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Public Interest Organizations

# Exhibit 46

# FERC Energy Primer

# Energy Primer

A Handbook for Energy Market Basics



FEDERAL ENERGY REGULATORY COMMISSION  
**Office of Energy Policy and Innovation**

# Energy Primer

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A Handbook for Energy Market Basics



FEDERAL ENERGY REGULATORY COMMISSION  
**Office of Energy Policy and Innovation**  
**December 2023**

This report is a product of the staff of the Federal Energy Regulatory Commission (Commission or FERC). The opinions and views expressed in this paper represent the preliminary analysis of the Commission staff. This report does not necessarily reflect the views of the Commission, its Chairman, or individual Commissioners, and is not binding on the Commission.

# ACKNOWLEDGMENT

The Energy Market Primer was originally issued in 2012 and has been updated several times since its first issuance. This update to the Energy Market Primer is the result of the combined efforts of many dedicated individuals throughout the Federal Energy Regulatory Commission (FERC or Commission). The team consisted of individuals from the Commission's Office of Energy Policy and Innovation, Office of Enforcement, Office of Energy Market Regulation, and Office of External Affairs. We specifically wanted to recognize the primary contributors to each chapter.

**Chapter 1: Wholesale Natural Gas Markets – Eric Primosch**

**Chapter 2: Wholesale Electricity Markets – Patricia Schaub**

**Chapter 3: Gas-Electric Interdependency – Thomas Pinkston**

**Chapter 4: U.S. Crude Oil and Petroleum Products Markets – Eric Primosch**

**Chapter 5: Trading and Capital Markets – Astrid Rapp and Gareth Jones**

**Chapter 6: Market Manipulation – Thomas Olson**

## IN MEMORIAM



### Lance Hinrichs

*Federal Energy Regulatory Commission  
Office of Energy Policy and Innovation*

Lance was instrumental in the creation and publication of the Energy Market Primer. He will forever be remembered as a dedicated public servant whose knowledge of energy markets was unsurpassed.



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# INTRODUCTION

Natural gas, electricity, and crude oil are forms of energy that are of particular interest to the Federal Energy Regulatory Commission (FERC) pursuant to its authority under the Natural Gas Act, the Federal Power Act, and the Interstate Commerce Act. This primer explores the workings of the wholesale markets for these forms of energy, as well as energy-related financial markets.

Energy markets consist of both physical and financial elements. The physical markets contain the natural resources, infrastructure, institutions and market participants involved in producing energy and delivering it to consumers. The financial markets include the buying and selling of financial instruments that derive value from the price of the physical commodity. These financial markets have their own set of market structures and institutions, market participants, and traded products which have their own drivers of supply and demand. In general, physical and financial markets can be distinguished by the products and by the intentions of the market participants involved.

Much of the wholesale natural gas and electric power industry in the United States trades competitively, while some markets and their prices are established through administrative processes based on the cost of providing service. In competitive markets, prices are largely driven by the economic concepts of supply and demand. Underlying the supply and demand for energy are physical fundamentals - the physical realities of how markets produce and deliver energy to consumers and how they form prices. These physical fundamentals will be covered in Chapter 1 (Wholesale Natural Gas Markets), Chapter 2 (Wholesale Electricity Markets), and Chapter 4 (U.S. Crude Oil and Petroleum Products Markets).

The significant shift in the U.S. fuel mix has heightened the importance over the past decade of the interdependence of the natural gas and electric systems. Given the importance of natural gas in electricity

generation, integration of market operations between the natural gas and electricity industries is critical. The primer provides an overview of natural gas and electric system interdependencies in Chapter 3, Gas-Electric Interdependency.

Market participants buy and sell energy based financial contracts for a number of reasons. Physical market participants, such as producers and large consumers, usually use financial contracts to manage price risk and to protect against price volatility. That is, financial contracts can serve as a tool for managing risk akin to insurance. Other market participants use the energy markets to speculate, or to assume a market risk in hope of profiting from market fluctuations. Additionally, companies turn to the capital markets if they need to raise or invest money. This primer explores the market participants, products, market mechanisms and trading at work for natural gas and electricity in the financial markets in Chapter 5, Financial Markets and Trading.

Where there are markets, there will be those who attempt to manipulate the markets for their own benefit. These practices undermine the market's ability to operate efficiently, reduce other market participants' confidence in the markets and distort market outcomes, including prices. Some of these practices are discussed in Chapter 6, Market Manipulation.

This primer is written to be used either as a traditional text – read front to back – or as a reference guide. Consequently, some material is repeated in different sections and references are provided to other parts of the primer where a concept is addressed in greater detail.

Further information about various aspects of energy markets and FERC regulation can be found at [www.ferc.gov](http://www.ferc.gov); then navigate to the Market Oversight tab. You can find the market oversight pages here: <https://www.ferc.gov/market-assessments>.



# Chapter 2

## Wholesale Electricity Markets

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## WHOLESALE ELECTRICITY MARKETS

Electricity is a physical product – the flow of electrical power. It is a secondary energy source, in that it results from the conversion of other energy forms such as natural gas, coal or uranium, or the energy inherent in wind, sunshine or the flow of water in a river. Electricity is not visible or directly observable, but it can be turned on and off and measured.

### **Quick Facts:** *Measuring Electricity*

A key measure of electricity used in industry is the rate at which it is produced, transferred, or consumed – how much energy per unit of time a generator produces, with the units of electricity called watts. Similar measures are kilowatts (kW) – 1,000 watts, and megawatts (MW) – 1,000 kilowatts. A watt, kilowatt, or megawatt is a unit of power.

The amount of electric energy generated, transmitted, or used over time is measured as the number of watt-hours (also expressed as kilowatt-hours, megawatt-hours, or gigawatt-hours).

The amount of electricity a generator can produce in an hour is its capacity, which is typically noted as megawatts. For example, a generator with a capacity of 100 MW can produce 100 MW in an hour. The amount of power consumed at any location is the demand at that point.



Electricity markets have retail and wholesale components. Retail service involves the sales of electricity to consumers and may involve retail markets; wholesale markets typically involve the sales of electricity among electric utilities and electricity traders before it is eventually sold to consumers. Because the Federal Energy Regulatory Commission (FERC) has jurisdiction over wholesale electric rates and not retail electric rates, this document focuses on wholesale electricity markets, although it does address retail demand and other instances where retail markets strongly influence wholesale markets.

Most wholesale electric markets rely upon competitive markets to set prices, but some prices are based on the service provider's cost of service. For wholesale markets, FERC either authorizes jurisdictional entities to sell at market-based rates or at cost-based rates.

Both market-based and cost-of-service prices are affected by physical factors or conditions that drive electric supply and demand – these factors are known as physical fundamentals. For example, weather affects both supply and demand. Fuel costs, capital costs, transmission capacity and constraints, and the operating characteristics of power plants affect the cost at which supply can be provided. The actual price for power is determined by the interaction of supply and demand. For example, extreme heat can drive up demand and require grid operators to activate less-efficient, more-expensive power plants, and consequently drive prices up.

# Electric Power Industry

## ELECTRICITY ON DEMAND

In the United States and other developed countries, consumers expect electricity to be available whenever they need it. Electricity use has grown as consumers integrate various devices and amenities such as lighting, refrigerators and computers into their everyday lives. Consumers also expect to pay reasonable prices for the electricity that they use.

Meeting these customer expectations requires substantial effort and activity. While technology continues to develop and advance, electric markets can only store a portion of the electricity required to serve electric loads. Thus, the vast majority of electricity must be produced instantaneously as needed. Further, unlike most other markets, electricity's historically inelastic demand does not move with prices. To provide electricity on demand, electric system operations have to be planned and conducted with that goal in mind. In the absence of significant amounts of storage and price responsive demand, operators must plan and operate power plants and the transmission grid so that demand and supply exactly match, every moment of the day, every day of the year, in every location.

## ECONOMIES OF SCALE

Electric power is one of the most capital-intensive industries. Generation, transmission and distribution require significant investment in capital intensive equipment, the costs of which are fixed. Spreading these significant fixed costs over more customers helps bring down the cost that each customer pays.

Thomas Edison's first street lighting project in the 1880s grew to electrifying whole neighborhoods, towns, and cities. Providing service over larger areas allowed utilities to take advantage of economies of scale and the cost per unit of production dropped as power plants grew larger and larger. The companies building these facilities were generally self-contained and not connected to each other. They owned and operated generation, transmission, and distribution facilities and were vertically integrated.

While successful for launching the electric utility industry, this market structure had limitations. The larger generating units were difficult to replace if they experienced unexpected shutdowns. As a result, the utilities held and maintained excess capacity in reserve (reserves) to ensure reliable electric service. These reserves were able to quickly replace electricity lost due to an unexpected shutdown or an unexpected increase in electric loads.

## RESERVE SHARING

The solution to high reserve costs was to share reserves with adjacent utilities. Instead of building and maintaining all of the capacity required to provide energy and sufficient reserves, utilities were able to pool their reserves and could buy power from their neighbors in times of need cutting their costs significantly as a result. To facilitate reserve sharing, utilities built interconnecting transmission lines between their transmission systems to deliver electricity in the event of a generator outage or some other system disruption. Today's bulk power grid began as a way to maintain reliable service while lowering costs. The value of reserve-sharing agreements led to the formation of power pools, the forerunners of today's regional transmission organizations.

Coordinating exchanges of energy and reserves also led to closer coordination of other utility functions, such as the process of determining which generating units to use to serve electric loads. Operators want to commit just enough capacity to ensure reliability, but no more than is needed. Over time, this coordination ultimately led to the creation of regional transmission organizations that use markets to determine the set of resources to reliably serve electric loads at least cost. These wholesale electricity markets operate over large regions of the country.

Regional coordination also was spurred by special circumstances, particularly in the West. Large federally owned dams on the Columbia and Colorado river systems generate power from the spring runoff of melting mountain snow. When the reservoirs are full and hydroelectric plants are generating plentiful amounts

of power, there is not enough local demand to use the available supply. Since hydropower was cheaper than any alternative, long distance transmission lines were built to deliver the excess power from the Northwest and Southwest to load centers in California. With these transmission interconnections in place, northwestern utilities found that they could get cheaper power from southern power generation at other times of the year. These seasonal and regional disparities in availability and price introduced a lively bilateral trading market.

In the 1960s, the electric power industry created an informal, voluntary organization of operating staff to aid in coordinating the reliable operation of the bulk electric system. Then, in 1965, the largest power blackout until that time hit the northeastern United States and southeastern Ontario, Canada, affecting 30 million people. The blackout led to the development of the National Electric Reliability Council in 1968, shortly thereafter renamed the North American Electric Reliability Council (NERC), and nine regional reliability councils.<sup>74</sup> Rather than serving as a power pool or other entity for sharing reserves, NERC focused on reliability. In 2006, using authority granted in the Energy Policy Act of 2005 (EPAct 2005), FERC certified NERC as the electric reliability organization for the United States, and reliability standards became mandatory and enforceable.

## ECONOMY ENERGY TRADE

Transmission interconnections between adjacent utilities were originally built for the primary purpose of delivering reserves in emergencies. However, this created excess transmission capacity, since these events were rare. The interconnections allowed utilities to trade power, which became profitable when the marginal cost of operating their generation was higher or lower than that of their neighbors. Transmission availability provided opportunities for utilities to save money by buying energy when it was cheaper than generating and

selling energy to utilities with higher costs. This is called economy energy trading.

## EVOLVING PUBLIC POLICIES

Evolving public policies, regulatory constructs and organizational structures shaped the electric power industry over its history. Five concepts that helped shape the electricity industry and markets are outlined below, and still affect the industry today.

## REGULATED MONOPOLIES

In the early years of the industry, investors provided funds and took ownership shares in the power stations and electric distribution systems. These utilities became regulated – typically by state agencies – to overcome concern they were natural monopolies in the areas they served, lacking competition, and to bring stability to a capital-intensive industry. Stability came from granting exclusive service territories (or franchises), transparent financial statements, and the formulaic setting of electricity rates that were subject to regulatory oversight and approval. Over time, many of the utilities issued stock, which gave stockholders a share of the company's ownership, commonly referred to as investor-owned utilities (IOUs). The regulatory model for setting electricity rates was almost exclusively cost of service-based until about 30 years ago. Today, retail electric rate regulation is largely still based on cost-of-service, while wholesale electric rate regulation has become increasingly market-based. State regulators are responsible for approving retail rates, as well as utilities' investments in generation and distribution facilities. Some states eventually developed elaborate integrated resource planning (IRP) processes to determine what facilities should be built.<sup>75</sup>

## NOT-FOR-PROFIT UTILITIES

Another approach to serving customers emerged in the form of nonprofit electric providers. In the early years of the industry, electrification started in towns and cities

74 In 2006, the North American Electric Reliability Council changed its name to the North American Electric Reliability Corporation (also referred to as NERC).

75 For additional background and context on the early years of the electrification of the U.S., National Museum of American History, *Powering a Generation of Change, Emergence of Electrical Utilities in America* (2002), <http://americanhistory.si.edu/powering/past/h1main.htm>.

where utility service was provided by municipal power agencies or city governments. The federal government also stepped in to develop and market electricity from the nation's significant hydroelectric resources. Finally, the Depression-era rural electrification program promoted customer-owned rural electric cooperatives and low-interest government loans. There are currently more than 1,700 municipal and almost 900 cooperative utilities in the United States.

## **POWER POOLS**

Power pools are multilateral arrangements with members ceding operational control over their generating units and transmission facilities to a common operator. Members provide incremental cost data about their units and system status data to the operator. The operator then runs an energy management system that uses the unit cost data to optimize the overall unit commitment and economic dispatch.

The first of the power pools was PJM, which began in 1927 for utilities to share their generating resources. The Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP) formed in 1941 to pool resources for the war effort. Later, the New York Power Pool was formed in 1966 and the New England Power Pool in 1971, in response to the 1965 Northeast blackout.

## **COMPETITION, PART 1: COMPETITIVE GENERATION AND OPEN ACCESS**

Environmental policy and initiatives to open the airline and trucking industries to competition helped shape the energy industry in the 1970s. A provision in President Carter's energy plan led to passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), which ushered in the next era.

PURPA established a program implemented by states and overseen by FERC to encourage the use of efficient cogeneration (using the heat from industrial or other processes to generate electricity) and small-scale renewable generation. FERC's role was to issue regulations for the program and certify that qualifying facilities (QFs)

met statutory requirements. States administratively set the price to be paid to these generators at the cost the utilities would avoid by purchasing the power rather than generating it themselves. Such prices are referred to as avoided-cost rates.

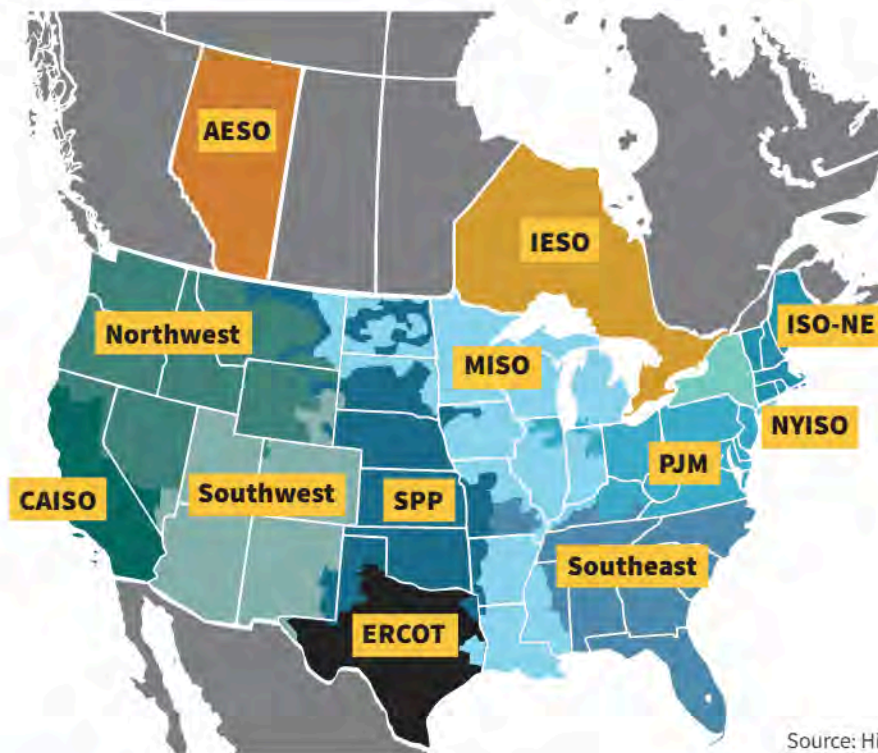
Most states set their avoided-cost rates so low that they got little QF capacity. However, California, Texas, and Massachusetts set relatively generous avoided-cost rates, and were overwhelmed with QF capacity, much of which received prices that turned out to be higher than the actual costs avoided by the purchasing utilities. The rapid growth and size of the QF industry surprised many policymakers and entrepreneurs and got them thinking about the viability of generation independent of regulated monopolies.

Under the original regulated monopoly model, utilities owned and operated the transmission lines with no obligation to allow others to use them. This posed a significant barrier to the development of an independent power industry. FERC started conditioning approval in merger cases on the utility's voluntary provision of open transmission access. The Energy Policy Act of 1992 gave FERC the authority to grant transmission access on request. These approaches to open access resulted in a patchwork of transmission access.

By the mid-1990s, support for opening the transmission grid to all users encouraged FERC to pursue a generic solution. FERC issued Order No. 888 in 1996 and required mandatory open transmission access by all transmitting utilities and a reciprocity provision successfully extended open access to non-jurisdictional entities (municipal, cooperative and federal utilities).

Order No. 889 addressed matters needed to implement open access. The rule established the Internet-based Open Access Same-Time Information System (OASIS) for posting available transmission capacity and reserving transmission capacity. These rules required significant changes to utility control room operations and limited the ability of companies to share transmission-related information with their own power marketing operating units.

**Figure 2-1: North American Regional Transmission Organizations, Independent System Operators and Bilateral Regions**



Source: Hitachi Energy, Velocity Suite

## COMPETITION, PART 2: INTEGRATING MARKETS AND OPERATIONS – ISOS AND RTOS

While the industry had historically traded electricity through bilateral transactions and power pool agreements, Order No. 888 promoted the concept of independent system operators (ISOs). Along with facilitating open access to transmission, an ISO would operate the transmission system independently of wholesale market participants and foster competition for electricity generation. Several groups of transmission owners formed ISOs, some from existing power pools.

In Order No. 2000, FERC encouraged utilities to join regional transmission organizations (RTOs) which, like ISOs, would operate the transmission systems and develop innovative procedures to manage transmission equitably. FERC’s proceedings in Order Nos. 888 and 2000, along with the efforts of the states and the industry, led to the voluntary formation of ISOs

and RTOs. Each of the ISOs and RTOs subsequently developed full-scale energy and ancillary service markets in which buyers and sellers could bid for or offer generation. Both organizations use bid-based markets to determine economic dispatch. Throughout the subsequent sections of the primer, when referring to the organized RTO and ISO markets generally and collectively, the term RTO/ISO is used.

Major parts of the country operate under more traditional market structures, notably the West (excluding California) and the Southeast. Two-thirds of the nation’s electricity load is served in RTO/ISO regions.

## Electricity Demand

Americans consume electricity for an ever-increasing range of uses. While consumption has grown over the years, it varies annually based on many influences, such

as weather, economic activity, and other factors. Total generation at utility-scale facilities reached 4,108,303 gigawatt hours in 2021.<sup>76</sup>

Vertically-integrated IOUs, federal entities, municipally owned, and electric cooperatives sell the majority of electric generation to retail consumers. Additionally, some retail consumers generate all or part of the power that they consume. The rest of the electricity ultimately consumed by customers is bought and sold through wholesale electricity markets.

## DEMAND CHARACTERISTICS

The amount of electricity consumed (demand) is continuously varying and follows cycles throughout the day and year. Regionally, electric demand may peak in either the summer or the winter. Spring and fall are considered shoulder months, with lower peak demand. Seasonal peaks vary regionally, although the highest levels of power load in almost all regions of the United States occur during summer heat waves, in the late afternoon. However, a minority of regions reach their peak load when the weather is extremely cold. These are primarily areas with significant space-heating requirements and little summer air conditioning load, such as the far northern areas of the United States.

Throughout the year, and in most locations, daily demand typically peaks in the late afternoon, as commercial and domestic activities peak, and in the winter, when lighting needs grow. Electricity use also varies between weekdays and weekends. Commercial and industrial activities are lower on weekends and peoples' noncommercial activities change with their personal schedules. The load on different weekdays can also show distinct usage. For example, Mondays and Fridays, being adjacent to weekends, may have different loads than Tuesday through Thursday. This is particularly true in the summer.

Since supply must rise and fall to provide exactly the amount of electricity customers need, the cost of

providing power typically rises as demand grows and falls as demand declines. This is because higher levels of demand require activation of increasingly expensive sources of power generation, and reductions as demand declines. As a result, power prices are typically highest during periods of peak demand.

## DEMAND DRIVERS

The amount of electricity demanded is insensitive to prices in the short-term. Electricity is a necessity to most people and businesses. While they may be able to reduce their demand in the short-term – by turning down the thermostat or turning off lights, for example – electricity consumers find it difficult to do without electricity altogether. Further, most customers – especially smaller customers – do not get price signals to which they can respond. A vast majority of residential customers are billed monthly on a preset rate structure. Large industrial customers, on the other hand, may receive real-time price signals.

In the longer-term, options for reducing electricity use include installing insulation and implementing other energy efficiency measures. Larger consumers may also consider building their own generation facilities.

As discussed below, utilities, at the direction of government, have developed demand-response programs, which can provide reduced rates or other compensation to customers who agree to reduce load in periods of electric system stress.

## Climate and Weather

Weather is one of the primary factors affecting demand. General climatic trends drive long-term consumption patterns and therefore the infrastructure needed to ensure reliable service.

Weather also can have extreme short-term effects on electricity usage. A sudden cold snap can drive heating use up quickly and a heat wave can push up air conditioning loads. Other, less obvious weather patterns affect demand

76 Derived from EIA, *Electric Power Annual*, Table 3.1.A (released November 8, 2022), [www.eia.gov/electricity/annual/html/epa\\_03\\_01\\_a.html](https://www.eia.gov/electricity/annual/html/epa_03_01_a.html).

– rain and wind, for example, may result in sudden cooling, affecting heating or air conditioning usage.

### **Economic Activity**

The overall level of economic activity affects power demand. During periods of robust activity, loads increase. Conversely, loads drop during recessions. These changes are most evident in the industrial sector, where businesses and plants may close, downsize, or eliminate factory shifts. In addition to reducing overall demand, these changes affect the pattern of demand; for example, a factory may eliminate a night shift, cutting off-peak use but continue its use of power during peak hours. In some cases, these effects can be significant. For example, the COVID-19 pandemic changed how consumers used electricity as communities and companies implemented social distancing and stay-at-home measures to combat the spread of COVID-19 in the spring of 2020. Electricity demand shifted from commercial and industrial uses to residential consumption. Overall, electricity demand in the U.S. dropped about 4% in 2020, as commercial and industrial demand dropped 6% and 8%, respectively, and residential demand rose 1%.<sup>77</sup>

### **Energy Policies and Regulations**

State regulatory agencies, such as public utility commissions, oversee retail electric rates and set policies affecting retail customer service. Some states allow utilities to offer retail rate structures that enable customers to receive more accurate price signals. They include, among other things, rates that vary with the time of day and the cost of providing electricity.

Efforts to reduce overall demand by improving energy efficiency are also supported by governmental and utility programs. These include rebates for the purchase of energy efficient appliances and home improvements, as well as capacity market payments for load reductions, also known as demand response, that are made available in certain markets.

### **Quick Facts: Heating and Cooling Degree Days**

In the United States, engineers developed the concept of heating and cooling degree days to measure the effects of temperature on demand. Average daily temperatures are compared to a 65°F standard - those in excess of 65° yield cooling degree days; those below 65° yield heating degree days. For example, a day with an average temperature of 66° would yield one cooling degree day.



### **Retail Customer Mix**

Most electric utilities serve three distinct classes of customers: residential, commercial, and industrial. Each class uses electricity differently, resulting in a differing load profile, or the amount of energy each customer class uses throughout the day. If a consumer uses electricity consistently throughout the day and seasons, the load shape is flat. Another consumer may use more at some times than others. More variable demand is typically more expensive to serve, especially if the peak occurs at the same time as other customers' use peaks. Consequently, the mix of customer types affects a region's overall demand and costs.

<sup>77</sup> EIA, *Short-Term Annual Outlook*, at 3 (January 2020).

**Residential consumers** form one of the top two customer segments in the United States at approximately 39 percent of electricity demand in 2021. Residential consumers use electricity for air conditioning, refrigerators, space and water heating, lighting, washers and dryers, computers, televisions, and other appliances. Prices for residential service are typically highest, reflecting both residential customers' load shape and their service from lower-voltage distribution facilities, meaning that more power lines and related assets are needed to provide service to them.

**Commercial use**, the next largest customer segment, represented approximately 35 percent of electricity demand in 2021.<sup>78</sup> This customer segment includes office buildings, hotels and motels, restaurants, street lighting, retail stores, wholesale businesses, and medical, religious, educational, and social facilities. More than half of commercial consumers' electricity use is for heating and lighting.

**Industrial consumers use** about 26 percent of the nation's electricity.<sup>79</sup> This customer segment includes manufacturing, construction, mining, agriculture and forestry operations. Industrial customers often see the lowest rates, reflecting their relatively flat load profile and their ability to take service at higher voltage levels.

**Transportation demand** for electricity stems primarily from trains and urban transportation systems. This is less than 1 percent of total electricity demand.<sup>80</sup> However, state and federal policies that advance electrification of the transportation fleet are expected to increase electric load growth in the near future.

## LOAD FORECASTING

Demand is constantly changing, which challenges grid operators and suppliers who are responsible for ensuring that supply will meet demand at all times. Consequently, they expend considerable resources to forecast demand.

Load forecasting uses mathematical models to predict demand across a region, such as a utility service territory or an RTO/ISO footprint. Forecasts can be divided into three categories: short-term forecasts, which range from one hour to one week ahead; medium-term forecasts, usually a week to a year ahead; and long-term forecasts, which are longer than a year. It is possible to predict the next-day load with an accuracy of approximately one to three percent of what will actually happen. The accuracy of these forecasts is limited by the accuracy of the weather forecasts used in their preparation and the uncertainties of human behavior.

The forecasts for different time horizons are important for different operations within a utility company. Short-term load forecasting can help to estimate transmission system power flows and to make decisions that can prevent overloading of transmission systems. Timely implementation of such decisions leads to the improvement of network reliability and to reduced occurrences of equipment failures and blackouts. Forecasted weather parameters are the most important factors in short-term load forecasts, with temperature and humidity as the most commonly used load predictors.

The medium- and long-term forecasts take into account historical load and weather data, the number of customers in different customer classes, appliances used in the area and their characteristics, economic and demographic data, and other factors. For the next-year peak forecast, it is possible to provide an estimated peak load based on historical loads and weather conditions. Long-term forecasts extending 10 to 20 years into the future are used for system infrastructure planning and are meant to ensure that there are sufficient resources available to meet the needs of the expected future peak demand.

Forecasts are necessary for the variety of actions that must occur to ensure that sufficient supply is available in the immediate and long term. These include the

78 Derived from EIA, *Electric Power Annual*, Table 2.5 (November 7, 2022), [www.eia.gov/electricity/annual/html/epa\\_02\\_05.html](http://www.eia.gov/electricity/annual/html/epa_02_05.html).

79 *Id.*

80 *Id.*

planning of long-term infrastructure, purchasing fuel and other supplies, and ensuring adequate staffing of specific personnel. Load forecasts are also extremely important for suppliers, financial institutions, and other participants in electric energy generation, transmission, distribution, and trading. Missed forecasts, when actual demand differs significantly from the forecast, can cause wholesale prices to be significantly higher or lower than they otherwise might have been.

## DEMAND RESPONSE

Electricity demand is generally insensitive to price, meaning that demand does not typically fall when prices rise. This occurs for several reasons, including that most end-use consumers of electricity are not exposed to real-time electricity prices. However, some utilities and grid operators have developed ways to stimulate a response from consumers through demand-response programs.

Demand response is the reduction in consumption of electricity by customers from their expected consumption levels, in response to either reliability needs or price signals. Customers will forego power use for short periods, shift some energy use from peak periods to other times, or use on-site generation in response to price signals or incentives for load reduction. The signals to respond to electric power system needs or high market prices may come from a utility or other load-serving entity, an RTO/ISO, or an independent provider of demand response. Both retail and wholesale entities administer these programs. Demand response has the potential to lower system-wide power costs and assist in maintaining reliability. It can also mitigate system stress and allow operators to resolve shortages, avoid operating inefficient power plants, or relieve transmission congestion. There can also be environmental benefits, such as lower levels of power plant-related emissions that result from not operating peaking units.

Measuring and verifying the amount of reduced consumption during a demand response activation requires development of consumers' baseline usage, against which their actual use is measured.

## Demand-Response Programs

Programs generally fall into three categories: curtailing, shifting, or on-site generation.

**Curtailing**, or forgoing, involves reducing power use (load) during times of high prices or threats to reliability without making up the use later. For example, residential customers might turn off lights or raise thermostats during hot weather. Commercial facilities may turn off office equipment, lower building lighting or change thermostat settings by a few degrees.

**Shifting** involves moving or rescheduling high energy-use activities in response to high prices or demand response program events to off-peak periods – evenings, nights, or weekends. Industrial customers might reschedule batch production processes to evening hours or the next day. Commercial establishments may delay high-energy operations. Residential customers may wait until evening or night to use high energy consuming appliances, such as clothes dryers or dishwashers. In shifting, the lost amenity or service is made up at a subsequent time.

**On-site generation** is when customers respond by turning on an on-site or backup emergency generator to supply some or all of their electricity needs. Although these customers may have little or no interruption to their electrical usage, their net load and requirements from the power system are reduced. The ability to use on-site generation is most common for institutional customers, such as hospitals, large schools, or data centers.

Demand response programs can be further distinguished by whether they are controlled by the system operator (dispatchable) or the customer (non-dispatchable). Dispatchable demand response refers to programs where the system operator can direct the customer to reduce its energy use, such as direct load control of residential appliances or directed reductions to industrial customers. Dispatchable demand response programs can be used for both reliability and economic reasons. Non-dispatchable demand response lets the retail customer decide whether and when to reduce

consumption in response to the price of power. This includes time-sensitive pricing programs that are based on rates that charge higher prices during high-demand hours and lower prices at other times.

As a result of technological innovations and policy directions, new types and applications of demand response are emerging that encompass the use of smart appliances that respond in near real-time to price or other signals. These models may allow customers to respond more easily, as they require little customer monitoring or interaction.

### **Retail Demand Response Programs**

Utilities and third-party aggregators offer a variety of demand response programs that include time-based rates and interruptible contracts. Also, some states mandate energy efficiency resource standards that include peak load reduction targets.

Time-based rates include time-of-use rates and dynamic pricing. Time-based rates depend on advanced meters at customer premises that can record usage over short increments, typically groupings of hours or individual hours. In time-of-use programs, customers are charged different prices at different times of the day, with hours on or near peak demand costing more than off-peak hours. Dynamic pricing is a category of programs where rates change frequently to better reflect system costs. The practice of adjusting prices as costs change provides an incentive for consumers to shift load to other periods or to reduce peak load. One form of dynamic pricing is termed real-time pricing. In these programs, customers are charged prices reflecting the immediate cost of power. Industrial or very large commercial customers are the most likely to choose real-time tariffs.

Another form of dynamic pricing is critical peak pricing. These programs use real-time prices at times of extreme system peak but are restricted to a limited number of hours annually. They feature higher prices than time-of-use prices during the critical peak. Consumers do not know in advance when a critical peak might be called. Critical peak programs for residential customers typically use rebates as an incentive to participate in the program, but customers take the risk of paying higher prices or reducing load during critical peak periods. These programs seek to have customers respond to price signals, as opposed to penalizing them, if they do not lower their use in the critical peak hours.

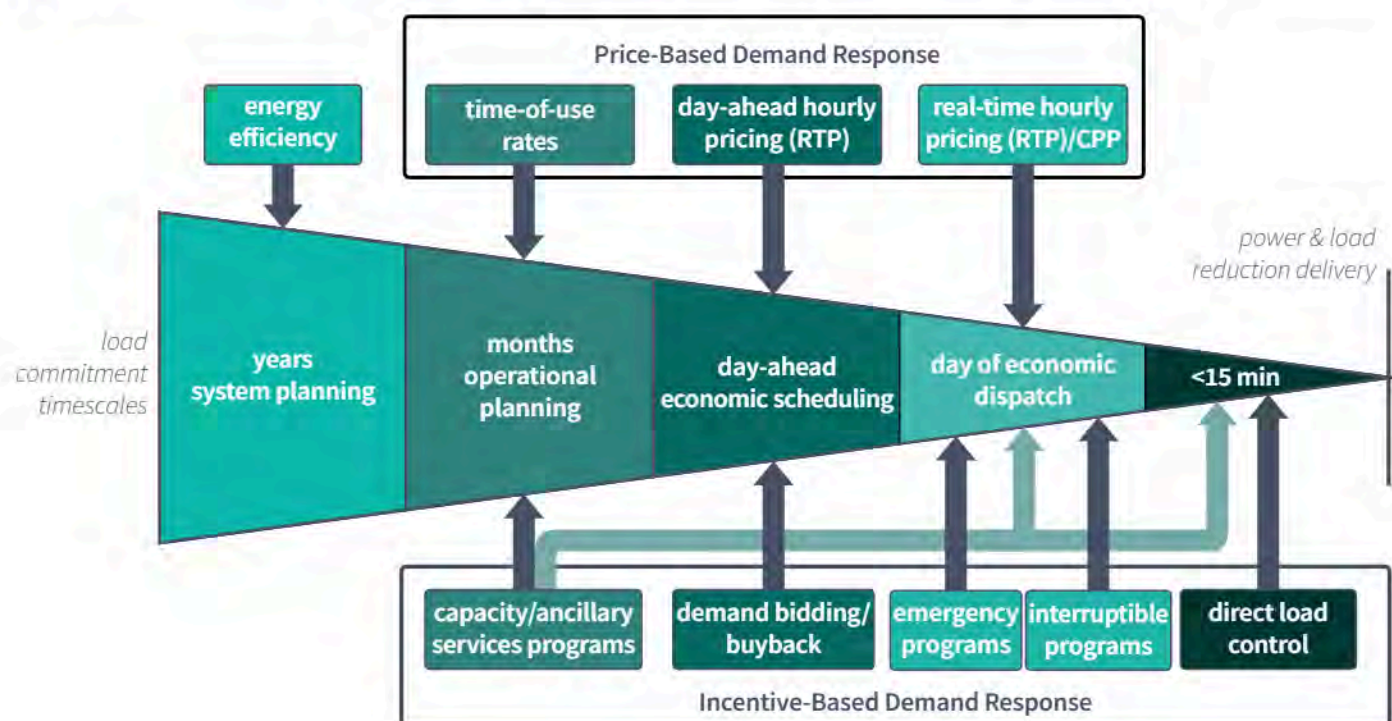
Interruptible contracts are used by utilities to control load and address potential reliability issues, such as reducing stress on the electric system during heat waves. The two primary forms of this category of demand response are direct load control and interruptible rates. Direct load control entails the utility curtailing a portion of customer load as described above. Under interruptible rates, customers agree to turn off equipment or switch their energy supply to an on-site generator.

Energy efficiency resource standards exist in 25 states, while five states and the District of Columbia, have energy efficiency goals.<sup>81</sup> The standards typically require utilities to achieve electric energy savings, and many include peak load reduction targets. These mandates provide incentives for utilities to reduce customers' energy consumption and include mechanisms that decouple profits from the amount of electricity sold or performance bonuses for utilities that meet or exceed reduction targets.

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81 DSIRE, N.C. Clean Energy Technology Center, *Energy Efficiency Resource Standards (and Goals) at 1* (September 2021), [https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2021/09/Energy-Efficiency-Resource-Standards\\_Sept-2021.pdf](https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2021/09/Energy-Efficiency-Resource-Standards_Sept-2021.pdf).

**Figure 2-2: Demand Response and Energy Efficiency in Electric System Planning and Operations**



Source: U.S. Department of Energy<sup>82</sup>

### Wholesale Market Demand Response Programs

On the wholesale level, market operators have some programs that dispatch the demand response resources. Other demand response programs are dispatched by the utilities or aggregators that sponsor the programs, rather than the market operator. Note that with most retail demand response programs, which can also aid wholesale markets, market operators may not be able to invoke them or even see the specific amount of response that occurs.

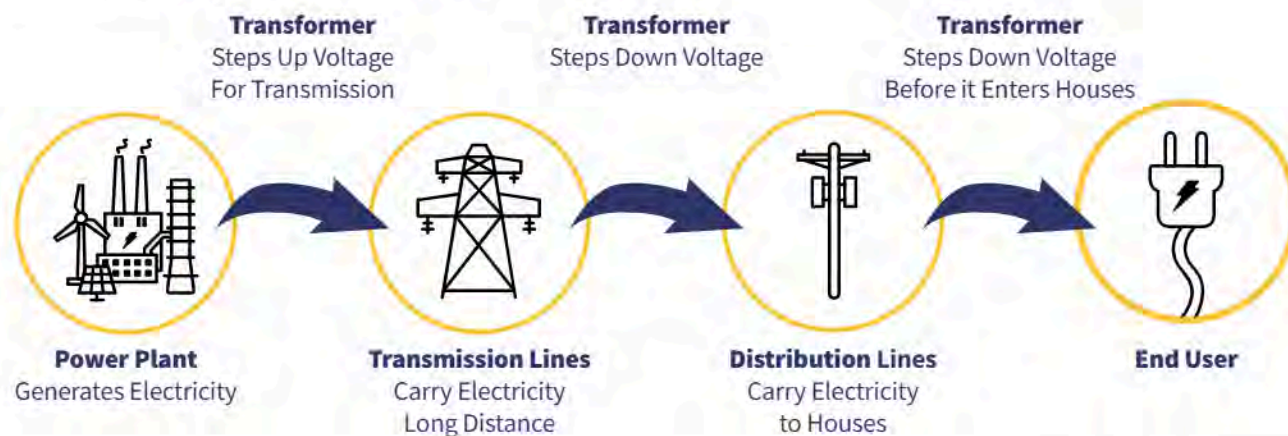
Demand response participation in RTO/ISOs has been encouraged in U.S. national energy policy and by various FERC orders.<sup>83</sup> Overall, approximately 30.8 GW of demand response participated in RTOs/ISOs in 2020.<sup>84</sup> These resources primarily participate in RTO/ISOs as capacity resources and receive advance reservation payments in return for their commitment to participate when called upon or activated. Additionally, demand resources may offer into the RTO/ISO day-ahead markets, specifying the hours, number of MWs and price at which they are willing to curtail.

82 U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005*, at 15, (2006), <https://www.energy.gov/oe/articles/benefits-demand-response-electricity-markets-and-recommendations-achieving-them-report>.

83 EPC Act 2005 included policy encouraging time-based pricing and other forms of demand response and the elimination of barriers to demand response participation in the energy, capacity, and ancillary services markets. Examples of FERC orders include Order No. 719, 128 ¶61,059, (July 16, 2009); Order No. 745, 134 ¶61,187 (March 15, 2011); and Order No. 2222, 174 ¶61,197, (March 18, 2021).

84 See FERC, *Assessment of Demand Response and Advanced Metering Staff Report*, at 3 (December 2021), <https://www.ferc.gov/media/2021-assessment-demand-response-and-advanced-metering>.

**Figure 2-3: Electricity Supply and Delivery**



Source: The NEED Project<sup>85</sup>

Some of the RTO/ISO demand response comes from individual entities; the rest is accumulated through third-party aggregators, or curtailment service providers, who recruit customers too small to participate on their own, such as schools, commercial chains or groups of residential customers. In aggregating small customers, curtailment service providers have increased customer participation in many wholesale reliability and emergency programs.

### **Demand Response and Energy Efficiency in Planning and Operations**

Different demand response programs can be used at various times to support planning and operations (see Figure 2-2). Energy efficiency programs that reduce baseload or peak demand over the long-term are incorporated into system planning. Dispatchable programs that are quickly implemented and targeted for short-term peak reductions – such as direct load control – lie on the other end of the spectrum and are used in the moment of operation.

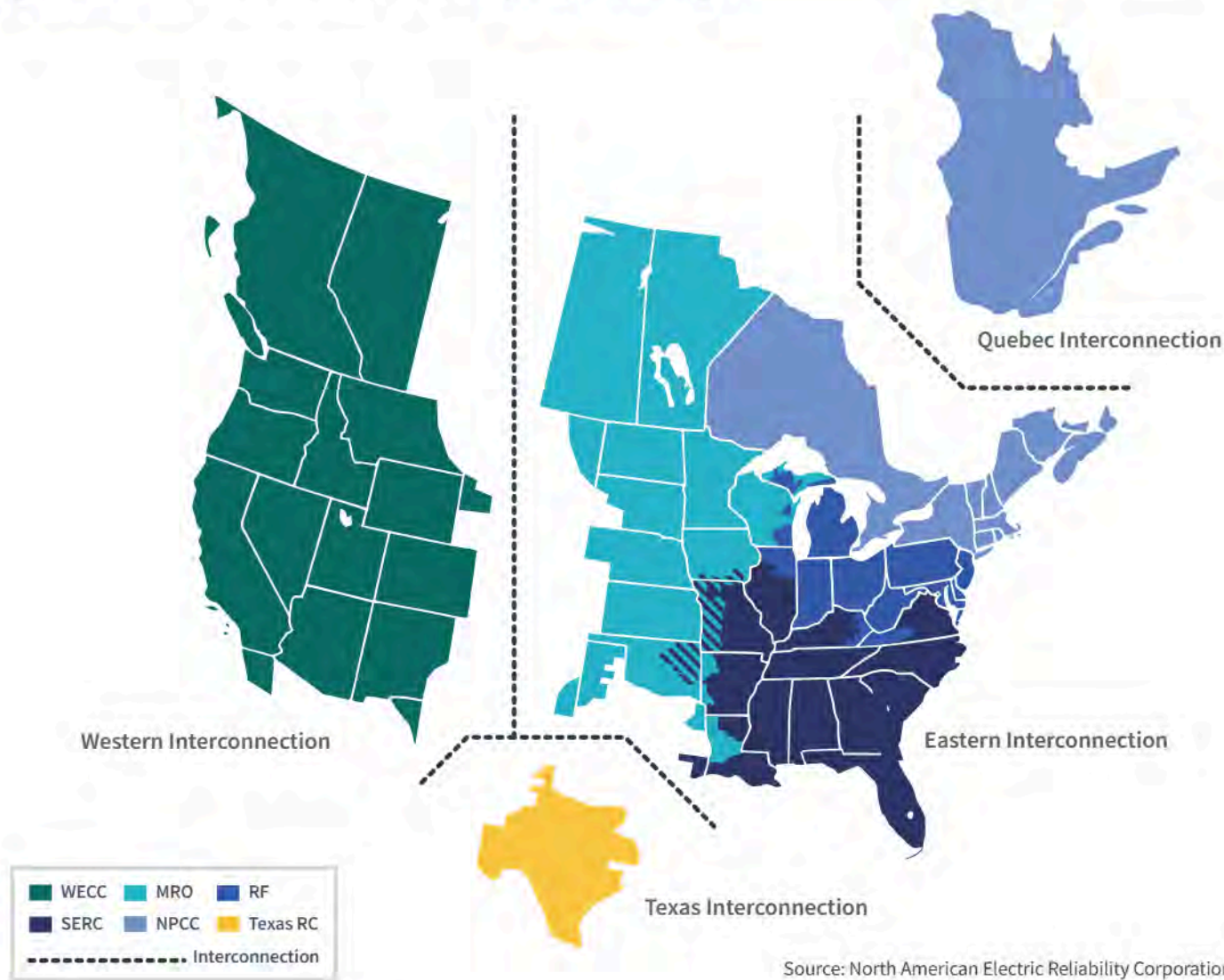
## **Electricity Supply and Delivery**

Unlike many other products, electricity cannot be stored in any appreciable quantity relative to the total consumed across the country each day. Further, electricity is a necessity for most consumers, whose use responds little to price changes. Finally, electric equipment and appliances are tuned to very specific standards of power, measured as voltage and frequency. For example, deviations in voltage can cause devices to operate poorly or may even damage them. Consequently, the supply side of the electricity market must provide and deliver exactly the amount of power customers want at all times, at all locations. This requires constant monitoring of the grid and close coordination among industry participants.

Electricity service relies on a complex system of infrastructure that falls into two general categories: generation and delivery services of transmission and distribution. Together, the power generation and high-voltage transmission lines that deliver power to distribution facilities constitute the bulk power system. Transmission and distribution facilities are also referred to as the power grid. These are coordinated, and at times operated by, a grid coordinator.

85 National Energy Education Development Project, *Electricity*, at 56 (2017), <http://www.need.org/Files/curriculum/infobook/Elec1S.pdf>.

**Figure 2-4: North American Electric Reliability Corporation Regions**



Nationally, the grid is geographically split into three main sections – the Western, Eastern and Texas Interconnections. These sections operate independently and have limited interconnections between them.

The nation, along with Canada and a small part of Mexico, is also divided into regional entities for reliability purposes. The regional reliability entities fall under the purview of North American Electric Reliability Corporations (NERC), which was designated by FERC as the nation’s electric reliability organization, and which develops and enforces mandatory reliability standards to better ensure the reliable operation of the nation’s bulk-

power system (the interconnected transmission grid). The reliability standards, once approved by FERC, must be met by applicable industry participants as designated in each reliability standard. Consequently, the grid is planned and operated to meet these standards.

NERC’s regions include:

- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability First Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Texas Reliability Entity (TRE)
- Western Electricity Coordinating Council (WECC)

## FERC JURISDICTION

Under the Federal Power Act (FPA), FERC regulates the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce. The FPA requires that every public utility file with FERC all rates and charges for any transmission or sale subject to the jurisdiction of FERC. Under Sections 205 and 206 of the FPA, 16 U.S.C. §§ 824d, 824e, FERC ensures that the 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 FERC, and all rules and regulations affecting, or pertaining to, such rates or charges are just and reasonable and not unduly preferential or unduly discriminatory.

## GENERATION

Power generators are typically categorized by the fuel that they use and subcategorized by their specific operating technology. In 2021, the United States had approximately 1,218 GW of total generating capacity.<sup>86</sup> The majority of power generation is produced from coal, natural gas, nuclear fuels, and renewables.

Power plants each have differing costs and operational characteristics, both of which determine when, where and how plants will be built and operated. Plant costs fall into two general categories: capital investment costs, which are amounts spent to build the plant, and operational costs, the amounts spent to maintain and run the plant. In general, there is a trade-off between these expenses: more capital-intensive plants tend to be cheaper to run – they have lower variable costs – and, conversely, the least capital intensive plants tend to be more expensive to run – they have higher variable cost. For example, nuclear plants produce vast amounts of power at low variable costs but are expensive to build. Conversely, natural gas-fired combustion turbines are far less expensive to

build but can be more expensive to run. Grid operators dispatch plants – or call them into service – with the simultaneous goals of providing reliable power at the lowest cost. Because various generation technologies have differing variable costs, plants are dispatched only when they are part of the most economic combination of plants needed to supply the customers on the grid. For plants operating in RTOs/ISOs, this cost is determined by the price that generators offer. In other areas, it is determined by the marginal cost of the available generating plants.

## CONVENTIONAL GENERATION

Generation is often described as conventional or renewable (described further in the Renewable Generation section below). Conventional generation typically includes natural gas-, oil-, coal- or nuclear-powered generation.

### Natural Gas-Fired Generation

Natural gas power plants consist of three major technologies, each with its distinct set of market advantages and limitations. They are steam boilers, gas turbines and combined cycle generators. Natural gas fuels nearly a third of U.S. electricity generation.

**Steam boiler** technology is an older design that burns gas in a large boiler furnace to generate steam at both high pressure and high temperature. The steam is then run through a turbine that is attached to a generator, which spins and produces electricity. Typical plant size ranges from 300 MW to 1,000 MW. Because of their size and the limited flexibility that is inherent in the centralized boiler design, these plants require fairly long start-up times to become operational and are limited in their flexibility to produce power output beyond a certain range. Furthermore, these plants are generally not as economical or easy to site as some newer technologies – which explains why few have been built in recent years.

<sup>86</sup> Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), <https://www.eia.gov/electricity/data/eia860m/>.

**Gas turbines (GT)** are small, quick-start units similar to an aircraft jet engine. These plants are also called simple cycle turbines or combustion turbines (CT). GTs are relatively inexpensive to build but are expensive to operate because they are relatively inefficient, providing low power output for the amount of gas burned, and have high maintenance costs. They are not designed to run on a continuous basis and are used to serve the highest demand during peak periods, such as hot summer afternoons. GTs also run when there are system-wide shortages, such as when a power line or generator trips offline. GTs typically have a short operational life due to the wear-and-tear caused by cycling. The typical capacity of a GT is 10-50 MW, and they are usually installed in banks of multiple units.

**Combined cycle power plants (CCPPs)** are a hybrid of the GT and steam boiler technologies. Specifically, this design incorporates a gas-combustion turbine unit along with an associated generator, and a heat recovery steam generator along with its own steam turbine. The result is a highly efficient power plant. They produce negligible amounts of SO<sub>2</sub>, and particulate emissions and their NO<sub>x</sub> and CO<sub>2</sub> emissions are significantly lower than a conventional coal plant. CCPPs, on average, require 80 percent less land than a coal-fired plant, typically 100 acres for a CCPP versus 500 acres for comparable coal plant, and CCPPs also use modest amounts of water compared to other technologies.

### Coal-Fired Generation

Coal plants produced approximately 22 percent of the electricity in the United States in 2021.<sup>87</sup> These facilities generate power by creating steam which is used to spin a very large turbine. These plants tend to be used as baseload units, meaning that they run continuously and are not especially flexible in raising or lowering their power output. They have high initial capital costs, with complex designs and operational requirements.

However, coal plants have low marginal costs and can produce substantial amounts of power. Most of the coal-fired plants in the United States are located in the Southeast and Midwest.

### Oil-Fired Generation

**Oil plants** generally produce only a small amount of the total electricity generated in the U.S. power markets. These facilities are expensive to run and also emit more pollutants than natural gas plants. They are frequently uneconomic and typically run at low-capacity factors. Like natural gas-fired generators, there are several types of units that burn oil; primarily, these are steam boilers and combustion turbines. Most dual-fuel power plants are located in the eastern half of the United States, especially on the East Coast.<sup>88</sup>

Generally, two types of oil are used for power generation: number 2 and number 6 (bunker) fuel oil. Number 2 is a lighter and cleaner fuel. It is more expensive, but because it produces fewer pollutants when burned, it is better for locations with stringent environmental regulations such as major metropolitan areas. Conversely, number 6 fuel oil is cheaper, but considered dirty because of its higher emissions. It is highly viscous (thick and heavy), and it comes from the bottom of the barrel in the refining process.

### Nuclear Generation

**Nuclear plants** provided roughly 19 percent of the nation's electricity in 2021, when 93 nuclear plants operated in the United States with a total capacity of approximately 100 GW.<sup>89</sup> Like generating units that use coal, nuclear plants tend to be large, baseload units that run continuously. Nuclear plants have high capital and fixed costs, but low variable costs, which includes fuel cost. They typically run at full power for 18 or 24 months, which is the duration of a unit's fuel cycle, and are then taken offline for refueling and maintenance. Outages

87 EIA, *Electric Power Annual* (November 7, 2022), *Generation at Utility Scale Facilities, Tables 3.1A. and 3.1.B.*, (accessed December 2022), [www.eia.gov/electricity/annual/html/epa\\_01\\_02.html](http://www.eia.gov/electricity/annual/html/epa_01_02.html).

88 Derived from Hitachi Energy, Velocity Suite data (Accessed March 28, 2023).

89 EIA, *Form EIA-860* (November 2022), [www.eia.gov/electricity/data/eia860/](http://www.eia.gov/electricity/data/eia860/).

typically last from 20 days to significantly longer, depending on the work needed. Of the 92 operating nuclear plants, most reside in the eastern United States. Only six are in the West, four in Texas. Illinois had the largest number of plants at 11, followed by Pennsylvania at eight, and South Carolina at seven.<sup>90</sup>

## RENEWABLE GENERATION

Renewable resources use fuels that are naturally replaced, such as wind, solar, hydroelectric and geothermal or which use fuels that are readily replaceable, such as biomass and biogas.

Such generation (generation termed renewable generation or renewables) is an increasingly important part of total U.S. supply, accounting for 29 percent of electric energy produced in 2021.<sup>91</sup> As total generation from all fuels has remained relatively constant in recent years, renewable generation's share has risen, spurred by technological advancements, state policy, and federal tax credits.<sup>92</sup>

Wind and solar capacity have grown faster than other renewable resources in recent years. Wind capacity grew substantially, from approximately 10 GW in 2006 to 193 GW in 2021.<sup>93</sup> Utility-scale solar capacity grew even faster, from approximately 0.1 GW to 61 GW over the same period.<sup>94</sup>

Additions of renewable generation capacity are usually reported in megawatts of nameplate capacity. Actual capability varies from the nameplate for any unit type due to such factors as age, wear, maintenance and ambient conditions. But as renewable resources are often weather-dependent, their capacity factors – the ratio of average generation to the nameplate capacity

for a specific period – have been lower (for example, approximately 30 percent), depending on the technology type, than for fossil-fuel generation. Grid operators pay close attention to the difference between nameplate and capacity factor values when they evaluate capacity available to cover expected load, however, capacity factors have risen with technological innovation and improved manufacturing processes.

### Wind

Wind generation is among the fastest-growing renewable resource, in part due to cost declines and technology improvements, as well as receipt of federal tax credits. Increases in average hub heights and rotor diameters have increased average wind turbine capacity. Because the best wind resources are often located far from load centers, obtaining sufficient transmission presents a challenge to delivering wind output. Other market challenges for future wind development include its variable output, which is often inversely correlated to demand (seasonally and daily); system operators' limited ability to dispatch wind resources to meet load increases; difficulties related to accurately forecasting its ramping; and the need for companion generation (usually fossil-fueled) or energy storage to be available to balance wind generation when the wind is not blowing.

### Solar

Solar generation transforms sunlight into electricity using one of two technologies: photovoltaic (PV) or concentrating solar power (CSP). PV modules, or panels, transform sunlight directly into power using cells made of silicon or thin-film materials. They can be installed on roofs of buildings or at ground-level PV farms. CSP plants use a two-step process to transform the sun's energy. First, mirrors direct sunlight towards a receiver that captures

90 EIA, *Form EIA-860M* (February 2023), [www.eia.gov/electricity/data/eia860M/](http://www.eia.gov/electricity/data/eia860M/).

91 Derived from EIA, *Electricity Annual* (September 2022), [www.eia.gov/electricity/annual/html/epa\\_01\\_01.html](http://www.eia.gov/electricity/annual/html/epa_01_01.html).

92 Lawrence Berkeley National Lab, *U.S. State Renewables Portfolio and Clean Electricity Standards: 2023 Status Update* (June 2023), [https://eta-publications.lbl.gov/sites/default/files/lbnl\\_rps\\_ces\\_status\\_report\\_2023\\_edition.pdf](https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2023_edition.pdf).

93 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), <https://www.eia.gov/electricity/data/eia860m/>.

94 *Id.*

the heat. CSP then employs a thermal process to create steam, driving an engine or turbine to produce electricity. CSP plants, which are dispatchable, can include low-cost energy storage that extends their availability later in peak hours. PV growth has increased greatly as a result of policy incentives and cost declines. Total PV generation for 2021 was 161.5 GW, with approximately two-thirds of that generation coming from utility-scale facilities and one-third from small-scale generation.<sup>95</sup>

By the end of 2021, 1.5 GW of CSP was operational – a decline from 2017 when CSP capacity was 1.8 GW.<sup>96</sup> Total CSP capacity is significantly lower than PV owing to PV's lower costs.<sup>97</sup> Seven western and southwestern states have extensive CSP potential: Utah, New Mexico, Arizona, Nevada, Texas, California and Colorado.<sup>98</sup> Developing that potential will require overcoming challenges of cost, siting, transmission, and the need for extensive water supplies to clean mirrors.

## Hydroelectric

Hydroelectric generation is powered by the kinetic energy of falling water that drives turbine generators, which convert the energy into electricity. There are two types of hydroelectric projects: conventional and pumped storage. Conventional projects, which use a dam in a waterway, can operate in a run-of-river mode, in which water outflow from the project approximates inflow, or in a peaking mode, in which the reservoir is mostly drained to generate power during peak periods when energy is more valuable. Pumped storage projects use bodies of water at two different elevations. Water is pumped into elevated storage reservoirs during off-peak periods when pumping energy is cheaper; the water is

then used to generate power during peak periods as it flows back to the lower elevation reservoir. In 2021, total U.S. hydro-electric capacity (including conventional and pumped-storage capacity) reached 246 GW. Conventional hydro-electric capacity was 285.3 GW and pumped storage hydro-electric capacity was 5.1 GW.<sup>99</sup>

## Geothermal

Geothermal generation taps into reservoirs of steam and hot water deep beneath the earth's surface to produce power. The majority of the plants are based in California and Nevada. Geothermal potential is determined by thermal conductivity, thickness of sedimentary rock, geothermal gradient, heat flow and surface temperature. Geothermal generation, which stood at 16 GW in 2021, increased from 0.6 GW in 2011, but has decreased as a portion of total renewable output, due to the growth of other renewables. California hosts about 76 percent of geothermal U.S. operating capacity.<sup>100</sup>

## Biomass

Biomass generation includes power production from many waste byproducts, such as agricultural residues, landfill gas, municipal solid waste, and wood resources. The largest biomass category is wood waste, burned for heat and power in the lumber, pulp and paper industries. Challenges to biomass production include impacts on food supplies (for example, converting corn into ethanol), conserving natural resources, and minimizing water pollution. In 2021, net utility-scale power generation using biomass fuel sources was 54.3 GWh - composed of 36.5 GWh from wood and wood-derived fuels as well as 17.8 GWh from other biomass sources.<sup>101</sup>

95 Derived from EIA, *Electric Power Annual, Tables 3.1.A. and 3.1.B* (released November 7, 2022 and accessed December 2022), [www.eia.gov/electricity/annual/html/epa\\_01\\_02.html](http://www.eia.gov/electricity/annual/html/epa_01_02.html).

96 Derived from EIA, See table 4.3 in *Electric Power Annual 2021 and Electric Power Annual 2017*, [www.eia.gov/electricity/annual/html/epa\\_04\\_03.html](http://www.eia.gov/electricity/annual/html/epa_04_03.html) and [www.eia.gov/electricity/annual/archive/pdf/03482017.pdf](http://www.eia.gov/electricity/annual/archive/pdf/03482017.pdf).

97 See National Renewable Energy Laboratory, *Annual Technology Baseline* (July 2018), <https://atb.nrel.gov/electricity/2018/summary.html>

98 EIA, *Form EIA-860*, (September 13, 2018), <https://www.eia.gov/electricity/data/eia860/>.

99 Derived from EIA, *Electric Power Annual* (November 7, 2022), *Generation at Utility Scale Facilities, Tables 3.1.A and 3.1.B* (accessed December 2022), [www.eia.gov/electricity/annual/html/epa\\_01\\_02.html](http://www.eia.gov/electricity/annual/html/epa_01_02.html).

100 Derived from EIA, *Form EIA-860* (accessed November 2017), <https://www.eia.gov/electricity/data/eia860/>.

101 *Id.*

## Biogas

Biogas energy is created through the anaerobic (without oxygen) bacterial decomposition of biodegradable waste, which is turned into a gas containing 60-70 percent methane. Biogas recovery is typically installed at farms and used to run farm operations and reduce methane emissions from natural manure decomposition.

## Renewable Energy Policies

Renewable generation development is frequently tied to policies promoting their use, which include tax credits, low-cost loans, rebates and production incentives. Federal funding of research and development has played an important role in lowering the costs or reducing the time it takes for renewable technologies to become commercially viable.

Congress has provided tax incentives to spur renewable resource investments. Originally enacted in 1992, federal production tax credits (PTC) are available for wind, biomass, geothermal, and other forms of renewable generation based on a facility's production. An inflation-adjusted credit, the PTC generally has a duration of 10 years from the date the facility goes online. The PTC has been revised several times, most recently in August 2022 under the Inflation Reduction Act, which extended the PTC for projects that begin construction before 2025, including solar projects that had previously been excluded from the PTC program.<sup>102</sup> After 2024, the PTC becomes technology neutral and emission based, and phases out starting in 2032, or when the U.S. electricity sector emissions are 75% below 2022 levels. If projects over 1 MW meet certain labor requirements, their PTC is 2.6 c/kWh; if the projects do not meet the labor requirements, the PTC would be 0.3 c/kWh. A further 10% adder on the PTC and ITC can be obtained if a project uses U.S. steel and roughly

half the of manufactured components (as measured by cost) are sourced in the United States.

Another form of tax credit for renewables, including solar and other types of projects, has been a federal investment tax credit (ITC). The ITC has generally been set at 30 percent of a project's equipment and construction costs. The Inflation Reduction Act also revised the ITC, with the same terms as for the PTC. Projects meeting labor requirements may receive a 30% ITC, otherwise the ITC drops to 6%. Projects may also receive a 10% increase in the ITC if they use U.S. components, as described for the PTC.

State renewable portfolio standards (RPS) and renewable energy standards (RES) have been significant drivers in the growth of investment in renewable generation. An RPS requires a certain percentage of energy sales measured by megawatt-hours (MWh) to come from renewable resources. Percentages usually increase incrementally from a base year to an ultimate target. Currently, 30 states plus Washington, D.C., have an RPS with financial penalties for non-achievement.<sup>103</sup> As utilities and independent developers build more renewable-powered generation, the markets in which they participate continue to address the integration of renewable output into their day-ahead and real-time operations, and incorporate the expected growth of renewable generation in their long-term transmission-planning processes.

Renewable energy certificates (RECs) allow state regulators to track compliance with mandatory RPS targets or verify progress in voluntary state renewable programs. They also allow compliance entities to purchase credits – subject to state-imposed limits on amount and price – if they have not generated or bought enough renewable energy to meet their annual requirements.

102 Congress.gov, *H.R. 5376-Inflation Reduction Act of 2022*, (became law August 4, 2022) <https://www.congress.gov/bill/117th-congress/house-bill/5376/text>.

103 Barbose, Galen. Lawrence Berkeley National Laboratory, *U.S. Renewables Portfolio Standards: 2021 Status Update: Early Release* (February 2021), [https://eta-publications.lbl.gov/sites/default/files/rps\\_status\\_update-2021\\_early\\_release.pdf](https://eta-publications.lbl.gov/sites/default/files/rps_status_update-2021_early_release.pdf).

## ELECTRIC STORAGE

Historically, utility-scale storage of electricity for later use had been limited to pumped-hydro storage facilities. Recent advances in technology have made other types of electric storage resources, including batteries and flywheels, more economically feasible. The lower costs and improved capabilities of electric storage, along with favorable state and federal policies, increased penetration of variable energy resources, and a continued focus on grid reliability have helped spur the development of electric storage resources.<sup>104</sup>

As of 2021, the combined capacities of utility-scale electric storage and battery storage represented less than 2 percent of total generating capacity in the United States.<sup>105</sup> The majority of storage capacity consists of pumped-hydro storage (21 GW in 2021), which has grown very slowly. Battery storage capacity, in contrast, has grown from 3 MW in 2016 to 4,482 MW in 2021.<sup>106</sup> EIA projects that total U.S. battery storage capacity could reach 30 GW by 2025.<sup>107</sup>

Electric storage projects are increasingly available to help balance supply and demand particularly during periods of high demand or excess supply. These resources can charge during periods of low demand or excess generation, when electricity is less expensive, and discharge when demand is high and electricity is more expensive. Batteries, flywheels, and other fast-acting electric storage technologies can also provide ancillary

services which help maintain grid reliability. The vast majority of battery storage capacity in the electricity markets is used to provide ancillary services or capacity, because these applications provide the most revenue for storage owners.<sup>108</sup>

Some states have passed legislation to incentivize investment in storage projects. In 2013, California adopted targets for utilities to procure 1,325 MW of energy storage capacity by 2024 and subsequently increased the capacity requirement target and compressed the timeline for reaching that target.<sup>109</sup> As of May 2021, five states besides California also set energy storage requirements or targets: Oregon, Massachusetts, New York, New Jersey and Virginia. Additionally, some states which do not have formal energy storage requirements offer financial incentives such as grants and tax incentives, while others have begun requiring utilities to include storage in integrated resource plans.

## DISTRIBUTED ENERGY RESOURCES

In Order No. 2222, the Commission defined Distributed Energy Resources (DERs) as any resource located on the distribution system, any subsystem thereof or behind a meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.<sup>110</sup> In most instances, these resources are located close to the

104 FERC has issued various orders to help remove barriers to the participation of electric storage resources in FERC-jurisdictional markets. See, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶61,127 (2018); *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020).

105 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), <https://www.eia.gov/electricity/data/eia860m/>.

106 *Id.*

107 EIA, *U.S. battery storage capacity will increase significantly by 2025* (December 8, 2022), <https://www.eia.gov/todayinenergy/detail.php?id=54939#:~:text=As%20of%20October%202022%2C%207.8%20GW%20of%20utility-scale,add%20another%2020.8%20GW%20of%20battery%20storage%20capacity>.

108 EIA, *U.S. Battery Storage Market Trends*, 13-15 (August 2021), [https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery\\_storage\\_2021.pdf](https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf).

109 California Public Utilities Commission, *Energy Storage* (accessed December 1, 2022), [www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-storage](http://www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-storage).

110 Order No. 2222, 172¶61,247, (September 17, 2020), at 4.

end user of power. While individual installations of DER tend to have capacities much smaller than that of central station power plants (for example DER installations may range from a fraction of a kW to systems producing less than 10 MW), the overall quantity of DER installations has grown tremendously, particularly in states with beneficial policies toward DERs.

One such policy is known as net metering, which is a system in which DERs are connected behind the meter to a distribution system and any surplus power is transferred onto the grid, allowing customers to offset the cost of power drawn from a distribution utility. Such surplus flow typically occurs during periods when the DER's production outstrips the customer's total demand. Under one measure of DER, as tracked by EIA, total net-metered capacity grew by approximately 277 percent between 2014 and 2020, from approximately 7.5 GW of capacity to 28.3 GW. The bulk of this capacity was solar PV, which made up 94 percent of net-metered capacity in 2020, with 62 percent of that capacity owned by residential customers.<sup>111</sup> In some cases, surplus power from a large DER or a set of net metered DERs may flow onto the transmission system.

## TRANSMISSION

The alternating current (AC) power grid operates like an interconnected web, where, with a few exceptions,

the flow of power is not specifically controlled by the operators on a line-by-line basis. Instead, power flows from sources of generation to consumers across any number of lines simultaneously, following the path of least resistance. There are also a limited number of direct current (DC) lines, which are set up as specific paths with definite beginning and end points for scheduling and moving power. These lines are controllable by operators and have other characteristics that make them attractive to grid planners and operators, such as providing greater grid stability and lower line losses. However, DC lines cost significantly more than AC lines to construct. Consequently, DC lines are typically built for certain specialized applications such as the movement of large amounts of power over long distances, for example the Pacific Intertie, which extends between the Northwest and California.

Transmission lines provide a certain amount of resistance to the flow of power as electricity travels through them. This resistance is not unlike the wind resistance that a car must overcome as it travels along a highway. The resistance in power lines creates losses: the amount of power injected into a power line diminishes as it travels through the line. The amount of these losses is contingent on many factors including the voltage of the transmission facilities.

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111 EIA, *Electric Power Annual* (December 2022), (March 2022), [www.eia.gov/electricity/annual/html/epa\\_04\\_10.html](https://www.eia.gov/electricity/annual/html/epa_04_10.html).

## Wholesale Electricity Markets and Trading

Electric markets encompass different organizational structures and different mechanisms for buying and selling power at the wholesale level. Electric systems for delivering power to consumers in the United States are split into two structures: traditional systems and those run by RTO/ISOs. Traditional systems are typically vertically integrated, rely on management to make operational decisions, and sell electricity to retail customers based on their cost of service. In general, RTO/ISOs use their markets to make operational decisions, such as generator dispatch, and to price the resulting electricity. Load-serving entities then buy the power through the RTOs/ISOs for resale to retail customers.

Both traditional systems and RTOs/ISOs conduct certain functions, although they may perform these functions in different ways. These include:

- Ensuring the electric grid operates reliably in a defined geographic footprint
- Balancing supply and demand instantaneously and maintaining sufficient operating reserves
- Dispatching system resources as economically as possible
- Coordinating system dispatch with neighboring balancing authority areas (BAAs)
- Planning for transmission in its footprint
- Coordinating system development with neighboring systems and participating in regional planning efforts
- Providing non-discriminatory transmission access

Buying and selling electricity in the wholesale markets – trading – occurs through bilateral and RTO/ISO transactions, as discussed below. Bilateral transactions occur in both traditional systems and in RTO/ISO regions. Pricing for bilateral transactions in both RTO/ISO and traditional regions incorporates both cost-based and market-based rates.

## SUPPLYING LOAD

Load serving entities (LSE) serve customer load through a combination of self-supply, bilateral market purchases and purchases from RTO/ISO markets. Self-supply means that the LSE generates power from plants it owns or operates to meet demand. With bilateral purchases, the LSE buys power from a supplier. RTO/ISO market purchases means the supplying company purchases power through the RTO's/ISO's markets.

LSEs' sources of energy vary considerably. In ISO-NE, NYISO, and CAISO, the LSEs have divested much or all their generation. In these circumstances, LSEs supply their customers' requirements through bilateral and RTO/ISO market purchases. In PJM, MISO, and SPP, LSEs may own significant amounts of generation, either directly or through affiliates, and therefore use self-supply as well as bilateral and RTO market purchases.

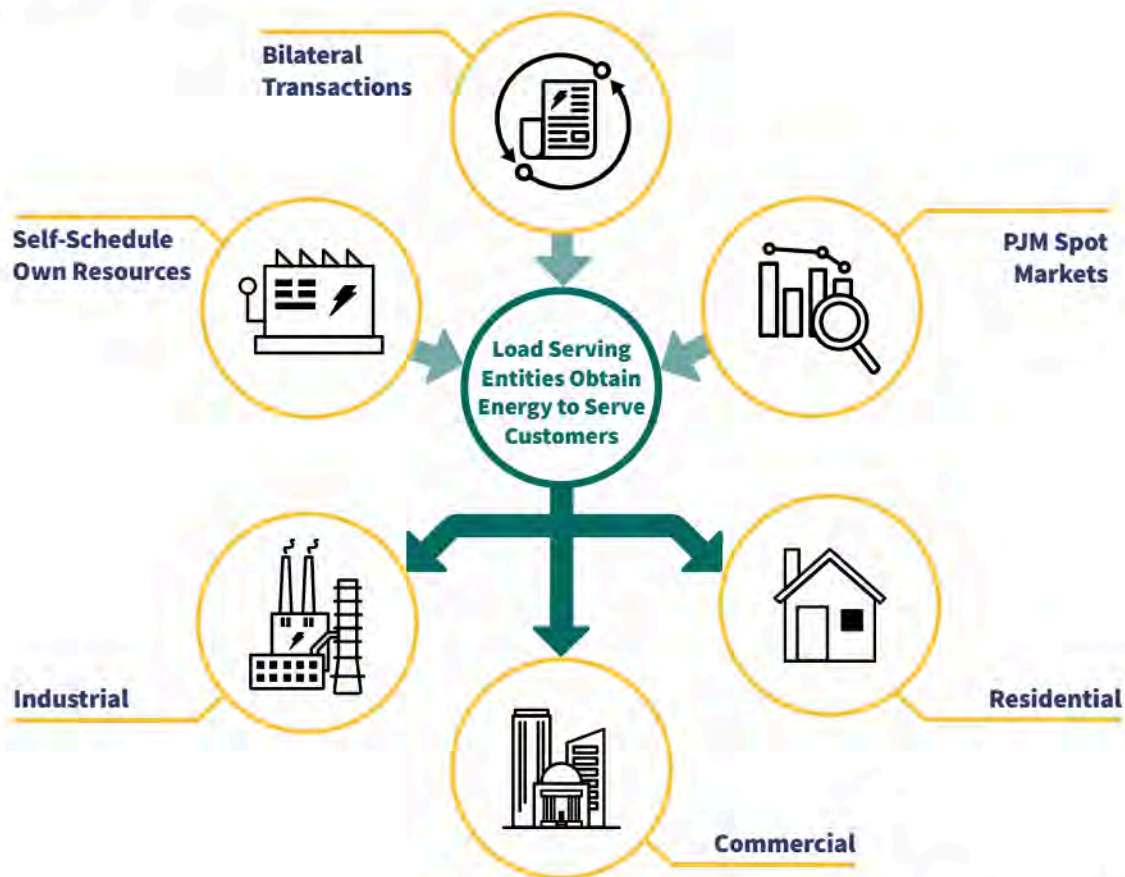
## BILATERAL TRANSACTIONS

Bilateral transactions between two parties do not occur through an RTO/ISO and can occur through direct contact and negotiation, through a voice broker or through an electronic brokerage platform, such as the Intercontinental Exchange (ICE). The deals can range from standardized contract packages, such as those traded on ICE, to customized, complex contracts known as structured transactions. In bilateral transactions, buyers and sellers know the identity of the party with whom they are doing business.

Whether the trade is done on ICE, directly between parties or through another type of broker, the trading of standard physical and financial products, such as next-day on-peak firm or swaps, allows index providers to survey traders and publish price indexes. These indices provide price transparency.

Physical bilateral trades involving the movement of energy from one point to another require the parties to reserve transmission capacity to move the power over the transmission grid. Transmitting utilities are required to post the availability of transmission capacity and offer

Figure 2-5: Options for Energy Supply



Source: PJM Traditional Wholesale Electricity Markets

service on an OASIS website. Traders usually reserve transmission capacity on OASIS at the same time they arrange the power contract.

Transfers of power between Balancing Authority Areas (BAAs) require one of the parties to the transaction to submit a request for interchange, also known as an eTag.<sup>112</sup> The receiving BAA (the entity to which the power is transferred or sinks), or its agent, will process the eTag, ensure a reliability assessment has been completed, and send it to all parties named on the eTag. This ensures an orderly transfer of energy and provides transmission system operators with the information that they need to

institute curtailments, as needed. Curtailments may be necessary when a change in system conditions reduces the capability of the transmission system to move power and requires some transactions to be reduced or cut.

Bilateral physical transactions that are conducted in RTO/ISOs are settled financially. Generators offer their power into the markets, and load is served through the power dispatched by the RTO/ISO. The RTO/ISO then settles bilateral transactions based on the prices in the contracts and the prices that occurred in their markets.

112 A BAA is a collection of generation, transmission, and loads within the metered boundaries of the entity (a Balancing Authority) that is responsible for balancing load, generation, and net interchange between other BAAs. Glossary of Terms Used in NERC Reliability Standards (March 2022), [https://www.nerc.com/files/glossary\\_of\\_terms.pdf](https://www.nerc.com/files/glossary_of_terms.pdf).

## COST-BASED RATES

Cost-based rates are used to price most transmission services and some electricity when FERC determines that market-based rates are not appropriate, or when an entity does not seek market-based rate authority. Cost-based rates are set to recover costs associated with providing service and give a fair return on capital. These rates are typically listed in a published tariff.

The following are major inputs to setting cost-based electricity rates:

- Determining used-and-useful electricity plant costs. This may include the cost of generation facilities, transmission facilities, distribution plants and office and related administration facilities.
- Determining expenses for the production, transmission and distribution of electricity, including fuel and purchased power, taxes and administrative expenses.
- Establishing a fair return on capital, known as the cost of capital. This includes determining the cost of debt, common equity, preferred stock and commercial paper and other forms of short-term borrowing, such as lines of credit used to finance projects and provide cash for day-to-day operations.
- Allocating electric plant and other expenses among various customer classes and setting the rate structure and rate levels.

## MARKET-BASED RATES

Under market-based rates, the terms of an electric transaction are negotiated by the sellers and buyers in bilateral markets or through RTO/ISO market operations. FERC grants market-based rate authority to electricity sellers that demonstrate that they and their affiliates lack, or have adequately mitigated, horizontal market power (typically based on whether the seller is a pivotal supplier and on the percent of generation owned by the seller relative to the total amount of generation available in a market). Sellers must also show that they lack, or have adequately mitigated, vertical market power (the ability to erect barriers to entry or influence the cost of production for competitive electricity suppliers). Wholesale sellers

who have market-based rate authority and sell into day-ahead or real-time markets administered by an RTO/ISO do so subject to the specific RTO/ISO market rules approved by FERC. Thus, a seller in such markets must have an authorization from FERC and must also abide by the additional rules contained in the RTO/ISO tariff.

## TRANSMISSION SERVICE

FERC requires that public utilities that own transmission lines used in interstate commerce offer transmission service on a nondiscriminatory basis to all eligible customers. The rates and terms of service are published in each utility's Open Access Transmission Tariff (OATT). Each utility's OATT specifies the transmission services available. Customers submit requests for transmission service through the OASIS. Utilities evaluate each transmission-service request using a model of the grid called a state estimator. Based on the model's estimation of the effects on the system, the request for transmission service is either approved or denied.

The two most common types of transmission service are network and point-to-point service. Network service allows a transmission customer the use of the entire transmission network to deliver generation from specified resources to specified loads. The price for service is cost-based and published in the OATT. Network service has higher priority than point-to-point service.

Point-to-point service involves paying for and reserving a fixed quantity of transmission capacity and moving power up to the reservation amount from one location, the point of receipt (POR), to another location, the point of delivery (POD). The POR and POD may be outside the transmission operator's footprint. Depending on availability, customers may purchase firm or non-firm point-to-point service for durations of one hour to multiple years.

Customers holding firm point-to-point transmission capacity may sell that capacity in a secondary market – such a sale is known as capacity reassignment. An entity holding transmission rights may want to resell

that capacity to another transmission customer in the secondary market because it is unneeded, or to make a profit. Resellers of transmission capacity are permitted to charge market-based rates for capacity reassignments, instead of the original cost-based rate at which they purchased the capacity. Most capacity reassignments are hourly, although capacity can also be reassigned on a daily, weekly, monthly, or yearly basis.<sup>113</sup>

If the market price of energy is greater at the POD than at the POR, the transmission has value. The transmission holder can capture this value by using the transmission – buying energy at the POR, moving it to the POD and selling it. Alternatively, the transmission holder can sell the transmission through a capacity reassignment. Thus, the price of a capacity reassignment should be consistent with, and rarely exceed, the expected price differential between the POD and the POR.

### **Transmission Planning**

Each transmission-operating utility must participate in regional planning processes that identify transmission system additions and improvements needed to maintain reliability. Studies are conducted to test the transmission system against mandatory national reliability standards, as well as regional reliability standards. Planning studies may look 10-15 years into the future to identify transmission overloads, voltage limitations, and other reliability problems.

## **GRID OPERATIONS**

Grid operators dispatch their systems using the least costly generation, consistent with the constraints of the transmission system and reliability requirements. The dispatch process occurs in two stages. For RTOs/ISOs, the market determines a day-ahead unit commitment, then updates the unit commitment and dispatches in real time. Grid operators in traditional utilities plan for the next day's dispatch, then update and implement that dispatch in real time.

### **Dispatch Planning**

Grid operators decide which generating units should be committed in advance of actual operations. For RTOs/ISOs, this is done, in part, through the day-ahead markets and forecasts. For operators in traditional utilities, this is done through various planning and forecasting processes. Planning dispatch in advance of real-time operations is needed because some generating units need to obtain fuel or require several hours of lead time before they are brought online. In selecting the most economic generators to commit, operators take into account forecast load requirements and each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels and the minimum time a generator must run once it is started. Operators must also take into account each generating unit's cost factors, such as fuel and nonfuel operating costs, and the cost of environmental compliance.

Forecast conditions can also affect how the transmission grid is optimally dispatched to reliably meet load. This is the security aspect of commitment analysis. The factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and weather conditions. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive generators may have to be called upon to replace less-expensive units.

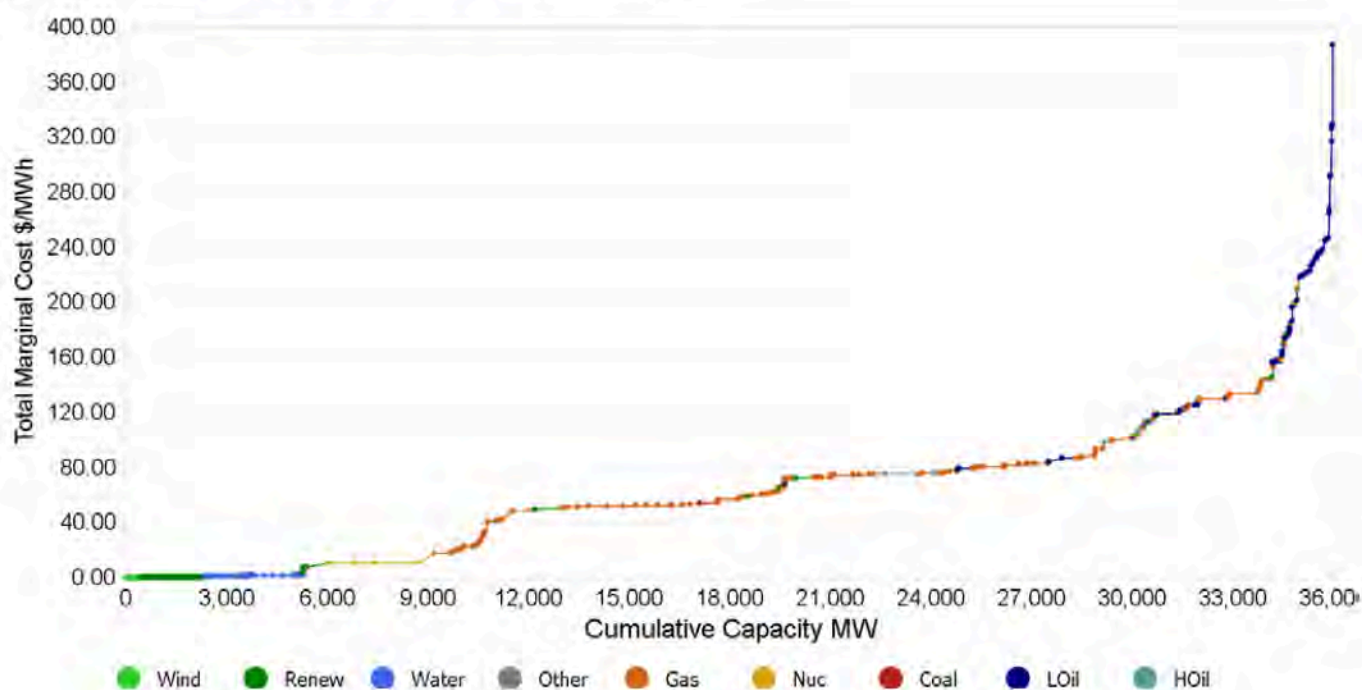
### **System and Unit Dispatch**

Grid operators must decide the actual level at which each available resource should be operated, given the actual real-time load and grid conditions, so that reliability is maintained and overall production costs are minimized. Actual conditions will vary from those forecast prior to real-time, and grid operators must adjust the dispatch accordingly. As part of real-time operations, demand, generation and interchange (imports and exports) must be continually kept in balance to maintain a system frequency of 60 hertz.

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113 FERC, *Electric Quarterly Reports, Downloads, Quarterly Filings* (2021), <https://eqrreportviewer.ferc.gov>.

**Figure 2-6: Market Supply Curve for NYISO (Illustrative)**



Source: Hitachi Energy, Velocity Suite<sup>114</sup>

This is typically done by automatic generation control (AGC) to change the generation dispatch as needed.

In general, dispatch occurs based on the cost of generation from given resources, with the lowest-cost resources dispatched first and the higher-cost resources dispatched last. The chart above is a depiction of the market supply curve for the New York Independent System Operator (NYISO). This is also commonly called the supply stack. In it, all the generating units in the New York market are shown, sorted according to their marginal cost of production. Their cost of production is shown on the vertical axis in terms of dollars per MWh. The cheapest units to run are to the left and the most expensive to the right.

Dispatch in New York, for example, first calls upon wind generating units, followed successively by hydroelectric, nuclear and coal-, gas- and oil-fired generating units.

This assumes that the generating units have sufficient resources – enough wind for the wind-powered generators or enough river flow for the hydroelectric plants, for example – and that sufficient transmission capability exists to deliver generator output and meet reliability needs.

In addition to these considerations, transmission flows must be monitored to ensure that the grid operates within voltage and reliability limits. If transmission flows exceed accepted limits, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch or shedding load. Operators may check conditions and issue adjusted dispatch instructions as often as every five minutes.

## ANCILLARY SERVICES

Ancillary services maintain electric reliability and support the transmission of electricity. These services

<sup>114</sup> Derived from Hitachi Energy, Velocity Suite, *Supply Curve Analyst, Form EIA 860, NERC Electric Supply and Demand database, FERC Form 1, FERC Form 714, ISO Load Data, Hitachi Energy Primary Research, et al* (February 2023).

are produced and consumed in real-time, or in the very near term. NERC and regional entities establish the minimum amount of each ancillary service that is required for maintaining grid reliability.<sup>115</sup>

**Regulation** matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal, typically every few seconds. The changes to output are designed to maintain system frequency at 60 hertz. Failure to maintain a 60-hertz frequency can result in systemic failure of an electric grid.

**Operating reserves** are needed to restore load and generation balance when a supply resource trips offline. Operating reserves are provided by generating units and demand resources that can act quickly, by increasing output or reducing demand, to make up a generation deficiency. There are three types: spinning reserves, non-spinning reserves and supplemental reserves.

**Spinning reserves** are provided by generators that are online (synchronized to the system frequency) with some unloaded (spare) capacity and capable of increasing its electricity output within a specified period, such as 10 minutes. During normal operation, these reserves are provided by increasing output on electrically synchronized equipment or by reducing load on pumped storage hydroelectric facilities. Synchronized reserve can also be provided by demand-side resources.

**Non-spinning reserves** are provided by generating units that are not necessarily synchronized to the power grid but can be brought online within a specified amount of time, such as 10 minutes. Non-spinning reserve can also be provided by demand-side resources.

**Supplemental reserves** are provided by generating units that can be made available within a specified

amount of time, such as 30 minutes and are not necessarily synchronized with the system frequency.

**Blackstart** generating units have the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the electric grid. Hydroelectric facilities and diesel generators predominately have this capability. These are the first facilities to be started up in the event of a system failure or blackout to restore the rest of the grid.

**Reactive power:** Electricity consists of current, the flow of electrons, and voltage, the force that pushes the current through the wire. Reactive power is the portion of power that establishes and maintains electric and magnetic fields in AC equipment. It is necessary for transporting AC power over transmission lines, and for operating magnetic equipment, including rotating machinery and transformers. It is consumed by current as it flows. As the amount of electricity flowing on a line increases, so does the amount of reactive power needed to maintain voltage and move current. Power plants can produce both real and reactive power and can change the output of both. Special equipment installed on the transmission grid is also capable of injecting reactive power to maintain voltage.

## WEATHER

Weather is the single most important factor affecting the level of electricity demand and, thus, is a major factor in grid operations. System operators therefore rely heavily on weather forecasts to ensure they have the right generation, in the right locations, to run the grid reliably.

Weather affects grid operations in other ways, as well. Primary among these is on the productivity of certain types of power generators: wind and hydroelectric. Wind turbines' power output changes

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115 For additional information on the definitions of ancillary services, NERC, *Glossary of Terms Used in NERC Reliability Standards*, (March 2022), [https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary\\_of\\_Terms.pdf](https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).

with wind availability and speed, which affects cost of wholesale power. Solar generation declines with cloud cover, which not only decreases available generation but can increase demand as behind-the-meter solar, such as residential and commercial installations, decrease their supply to retail users.

Hydroelectric plants rely on rain and snowfall to provide the river flow needed for their output. Geographically, this is most important in the Pacific Northwest, where seasonal hydroelectric plant output is a critical source of power. Rain and the melting of winter snowpack feed the Columbia and Snake

River systems. Surplus power from these generators is typically exported to California to help meet summer peak demand, increase reliability and lower prices.

Temperature can also affect the output of other power plants and capacity of transmission lines. Thermal plants that use a turbine – coal, gas, oil, and nuclear plants – become less efficient at higher temperatures. Additionally, the capacity of transmission lines is limited by heat because the conductive material used in fabrication becomes more electrically resistant as they heat up, limiting their throughput capability.

## Traditional Electricity Systems

Traditional wholesale electricity markets exist primarily in the Southeast and the West outside of California, where utilities are responsible for system operations and management, and, typically, for providing power to retail consumers. Utilities in these markets are frequently vertically integrated – they own the generation, transmission and distribution systems used to serve electricity consumers. They may also include federal systems, such as the Bonneville Power Administration (BPA), the Tennessee Valley Authority and the Western Area Power Administration. Wholesale physical power trading typically occurs through bilateral transactions. In addition to the responsibilities listed in the overview to this section, a utility in a traditional region has the following responsibilities:

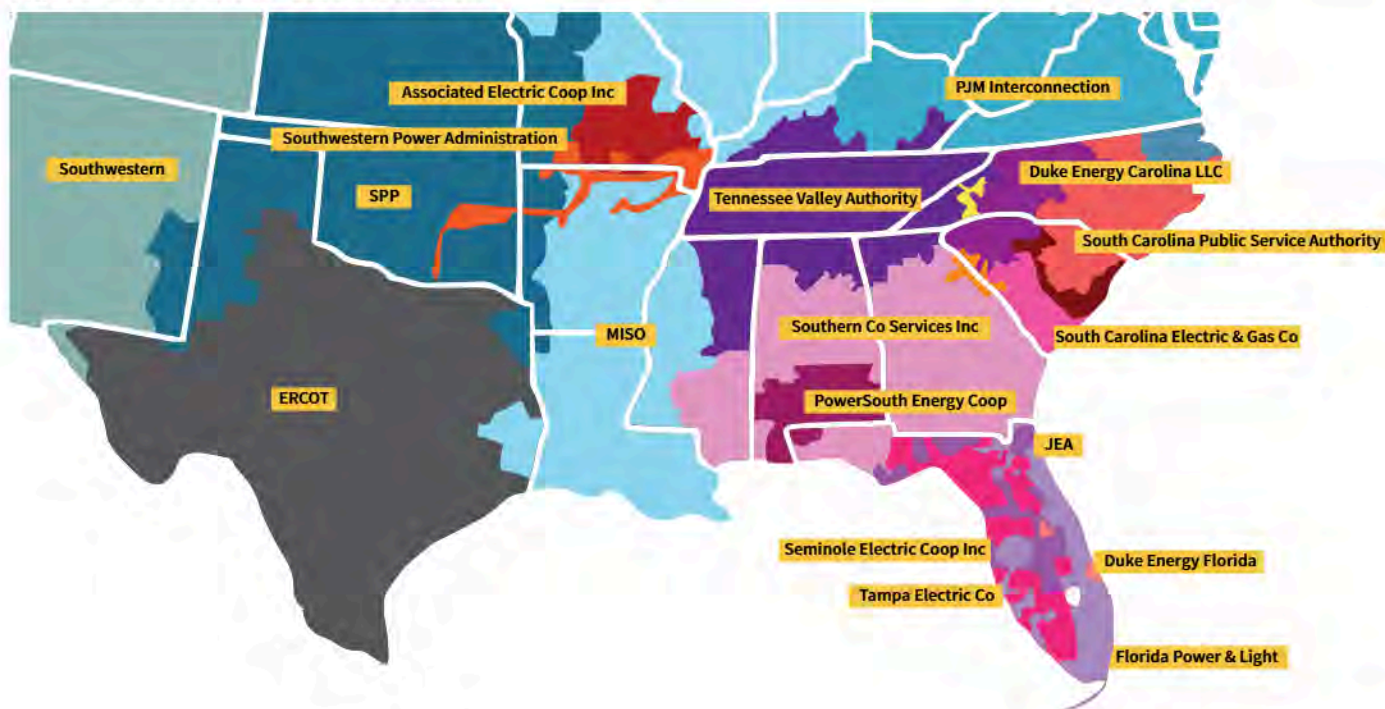
- Generating or obtaining the power needed to serve customers (this varies by state)
- Dispatching resources based on some cost minimizing algorithm

- Ensuring the reliability of the transmission grid

## Southeast Wholesale Market Region

The Southeast electricity market is a bilateral market that includes all or parts of Florida, Georgia, Alabama, Mississippi, North Carolina, South Carolina, Missouri, and Tennessee. It encompasses the Southeastern Electric Reliability Council (SERC) NERC region. Major hubs include Into Southern and the Tennessee Valley Authority (TVA). The Southeast region's hourly peak demand is greater than 203 GW.<sup>116</sup> While traditional bilateral trading continues in the Southeast, some utilities in the region have created a trading platform, the Southeast Energy Exchange Market (SEEM), discussed further below. Southern Company also conducts an auction for some of its available generation, also discussed further below.

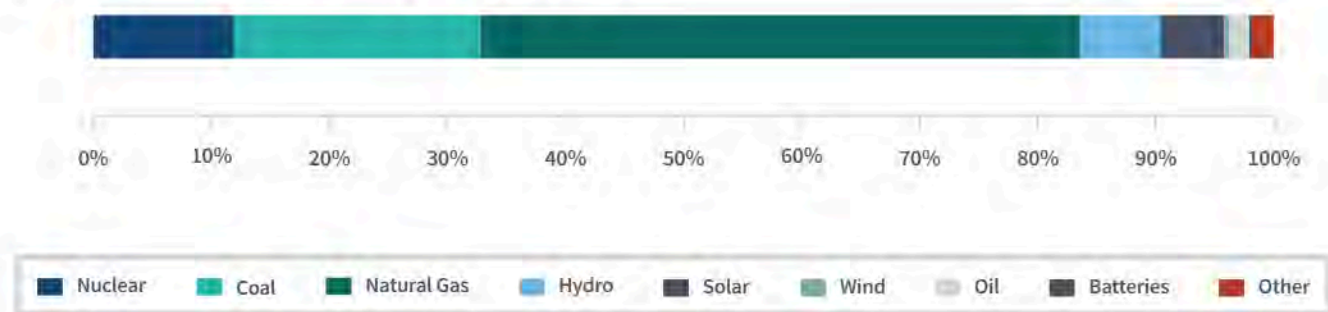
Figure 2-7: Southeast Electric Region



Source: Hitachi Energy, Velocity Suite

116 The hourly peak demand observed between 2000 and 2020. Based on FERC Form 714, Annual Electric Balancing Authority Area and Planning Area Report. Derived from the Balancing Authority Areas within the SERC NERC region, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

**Figure 2-8: Southeast Electric Region Capacity Mix**



Source: EIA Form 860-M<sup>117</sup>

## Supply Resources

The total generating capacity in the Southeast Electric Region is over 256 GW and is predominately composed of natural gas and coal-fired generators. Hydroelectric and nuclear capacity are also substantial resources in the region.

The Southeast generates most of its electricity from coal, nuclear, and natural gas-fired plants, as shown in the bar chart above.

The TVA sub-region has a majority of its capacity and output from coal and nuclear, while the Virginia-Carolina (VACAR) sub-region has the highest utilization of nuclear generation in the Southeast.

## TRADING AND MARKET FEATURES

Physical sales in the Southeast are done bilaterally and long-term energy transactions are particularly prominent, compared to short-term transactions. Many long-term agreements involve full-requirements contracts or long-term power purchase agreements. For example, Southern Company's short-term transactions account for around 30 percent of its total wholesale energy sales in 2021.<sup>118</sup>

Short-term energy is traded among various entities, including investor-owned utilities, municipal utilities, public utility districts, independent power producers, and marketers. Some of the largest sellers of short-term power include Southern Company, North Carolina Municipal Power Agency, Cargill, and Exelon.

Industry-referenced trading points for short-term bilateral transactions in the Southeast include the following locations: Into Southern, TVA, VACAR, and Florida. Volumes for short-term transactions can be low, particularly under normal weather conditions. Overall demand for short-term transactions tends to rise during periods of system stress, for example summer heat waves or winter cold snaps.

The Southeast has relatively low volumes of short-term trades compared to the Western regions. Thus, there is limited data on that price index publishers have on which to base their price reporting. Given the bilateral nature of wholesale power transactions in the Southeast, and a relatively small market for short-term transactions, interest in financial power products in the Southeast is weak.

117 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (released February 2022), <https://www.eia.gov/electricity/data/eia860m/>.

118 FERC, *Electric Quarterly Reports, Downloads, Quarterly Filings* (2021), <https://eqrreportviewer.ferc.gov>.

## SOUTHEAST ENERGY EXCHANGE MARKET

The Southeast Energy Exchange Market (SEEM) launched on November 9, 2022. However, on July 14, 2023, the U.S. Court of Appeals for the D.C. Circuit remanded to FERC orders addressing the Seem. Consequently, the SEEM proposal is now pending before the Commission once again.

## SOUTHERN COMPANY AUCTION

Southern Company has held daily and hourly auctions for power within its balancing area since April 2009 as a requirement of Southern Company's market-based rate tariff. This BAA encompasses the service territories of Southern Company utilities: Georgia Power, Alabama Power, Mississippi Power, and Gulf Power. The products included in the auction are day-ahead power and real-time power.

According to the auction rules, Southern Company must offer all of its available uncommitted thermal generation capacity into the auction, after regulation and contingency reserves are met. The auction is intended to mitigate the potential ability of Southern Company to exercise market power within its balancing authority area and certain adjacent balancing authority areas. In February 2017, Southern Company revised its market-based rate tariff to

cap all market-based sales of less than one year outside of the auction at a cost-based tariff rate.<sup>119</sup>

## Western Wholesale Market Regions

The power markets in the western United States are primarily bilateral markets. A key exception is most of California and portions of Nevada, which operate under CAISO. Further, several entities buy and sell electricity in a regional, short-term markets run by CAISO, called the Western Energy Imbalance Market (WEIM), and the SPP-run Western Energy Imbalance Service (WEIS). CAISO and SPP are discussed further in the RTO and ISO Markets section. The West includes the Western Power Pool (WPP), the Rocky Mountain Power Area, and the Arizona, New Mexico, Southern Nevada Power Area within the Western Electricity Coordinating Council (WECC), a regional entity. These areas contain over 30 balancing authority areas responsible for dispatching generation, procuring power, operating the transmission grid reliably, and maintaining adequate reserves.<sup>120</sup>

## NORTHWEST ELECTRIC REGION

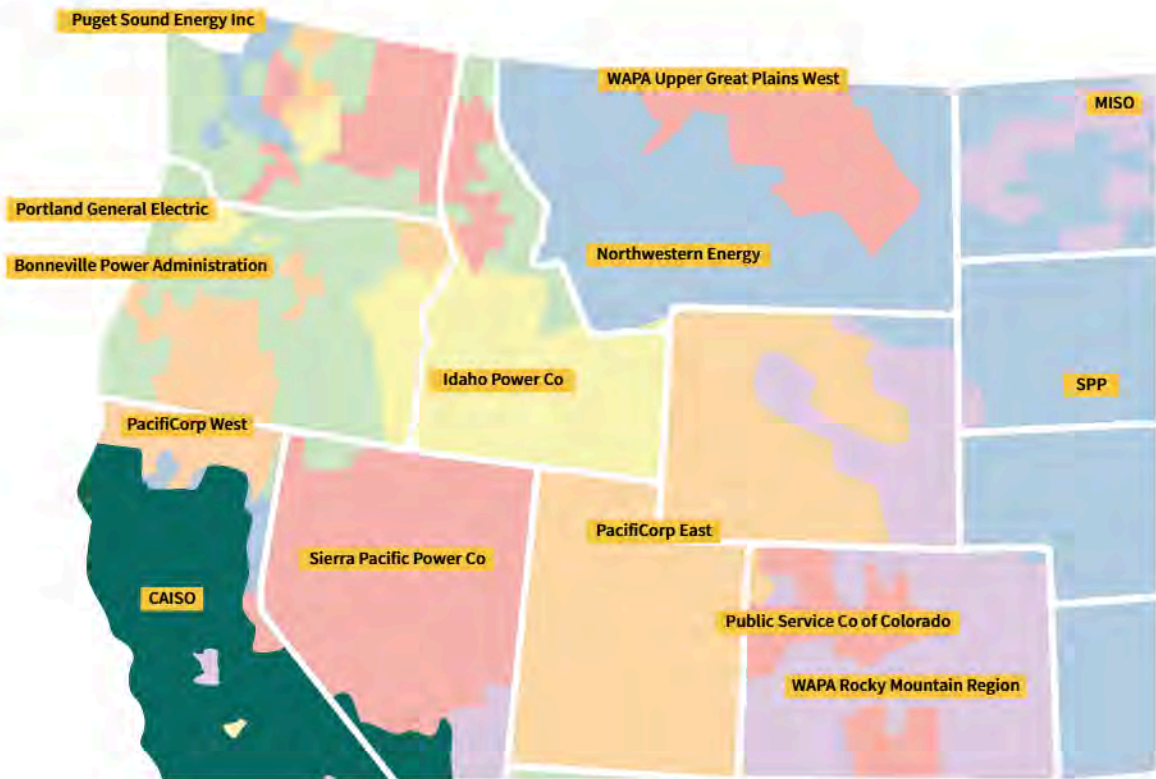
The Northwest Electric Region is composed of the Northwest Power Pool (NWPP) NERC region in the northwestern section of the Western Electric Coordinating Council (WECC) NERC region. The hourly peak demand is approximately 49 GW<sup>121</sup>

119 *Alabama Power Company*, 158 FERC ¶ 61,131 (2017) (February 2, 2017 Order) (order accepting market-based rate tariff revisions subject to condition).

120 Western Electricity Coordinating Council, *Western Interconnection Balancing Authorities* (accessed November 2022), [https://www.wecc.org/layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/Balancing\\_Authorities\\_JAN17.pdf&action=default&DefaultItemOpen=1](https://www.wecc.org/layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/Balancing_Authorities_JAN17.pdf&action=default&DefaultItemOpen=1).

121 The hourly peak demand observed in a given month between 2000 and 2020. Based on FERC Form 714, *Annual Electric Balancing Authority Area and Planning Area Report*. Derived from the Balancing Authority Areas within the NWPP NERC subregion, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

**Figure 2-9: Northwest Electric Region**



Source: Hitachi Energy, Velocity Suite

### Supply Resources

The total capacity in the Northwest Electric Region is approximately 79 GW and is primarily composed of hydroelectric, natural gas, and coal-fired generators, as shown in the bar chart below. Wind generator capacity is also a significant resource for the region.

The Northwest has a unique resource mix, as demonstrated in the bar chart below, with hydroelectric generation capacity comprising approximately 40 percent of the power supply, which is sourced from many dams that are in the Columbia River system. The largest dam, Grand Coulee, can produce up to as much power as six nuclear plants. Due to the large amount of hydroelectric generation, the Northwest typically has low-cost power during the spring and early summer. During these periods, the region exports power to neighboring regions, especially California, where power prices are typically higher.

The amount of hydroelectric power produced depends on a number of factors, some natural and some controllable. On a seasonal basis, the intensity and duration of the water flow is driven by snowpack in the mountains, the fullness of the reservoirs, and rainfall. On a short-term basis, the levels of hydroelectric power generation output are influenced by decisions to release water locally and upstream to generate power, as well as local water-use decisions that are independent of the economics of the power markets, based on recreation, irrigation, and wildlife considerations, for example. The peak hydroelectric power generation period begins in the spring, when the snow melts, and may last into early summer. When less water is available, the Northwest may rely more on its coal and natural gas generation, and occasionally import power from neighboring regions, including Canada, when loads are high.

**Figure 2-10: Northwest Electric Region Capacity Mix**

Source: EIA Form 860-M



## Trading and Market Features

Two Canadian BAAs, Alberta Electric System Operator

The water forecast affects the forward market for electricity in the Northwest. Similarly, the daily water flow conditions influence the prices in the daily physical market. When there is an abundance of hydroelectric generation, the Northwest will export as much as possible on the transmission lines leading into California and elsewhere in the West. Sometimes in off-peak hours, more electricity is available than can move through transmission lines or be used locally, so electric prices become negative.

The largest seller of wholesale power in the region is the BPA, a federal agency that markets the output from federally owned hydroelectric facilities, as well as a non-federal nuclear plant and several other smaller non-federal power plants. BPA meets approximately one-third of the firm energy supply in its service territory and owns 75 percent of the region’s high-voltage transmission.<sup>122</sup> BPA gives preference to municipal and other publicly owned electric systems in allocating and pricing its generation output.<sup>123</sup>

and British Columbia Hydro, are also substantial suppliers of energy to the United States via the Northwest Electric Region. These Canadian BAAs often import power to, and export power from, the United States, depending on market conditions. The Canadian BAAs generally import power from the United States when prices are low in order to save water in their hydroelectric reservoirs. The water is later released to generate and sell hydroelectric power during higher-priced periods<sup>124</sup>

The Northwest region trading points for bilateral transactions include Mid-Columbia (Mid-C), California-Oregon Border (COB), Nevada-Oregon Border (NOB), and Mona (Utah). Of these, Mid-C is the most actively traded location.

## SOUTHWEST ELECTRIC REGION

The Southwest electric market encompasses Arizona, New Mexico, and Southern Nevada in the WECC NERC region. The hourly peak demand is approximately 25 GW.<sup>125</sup>

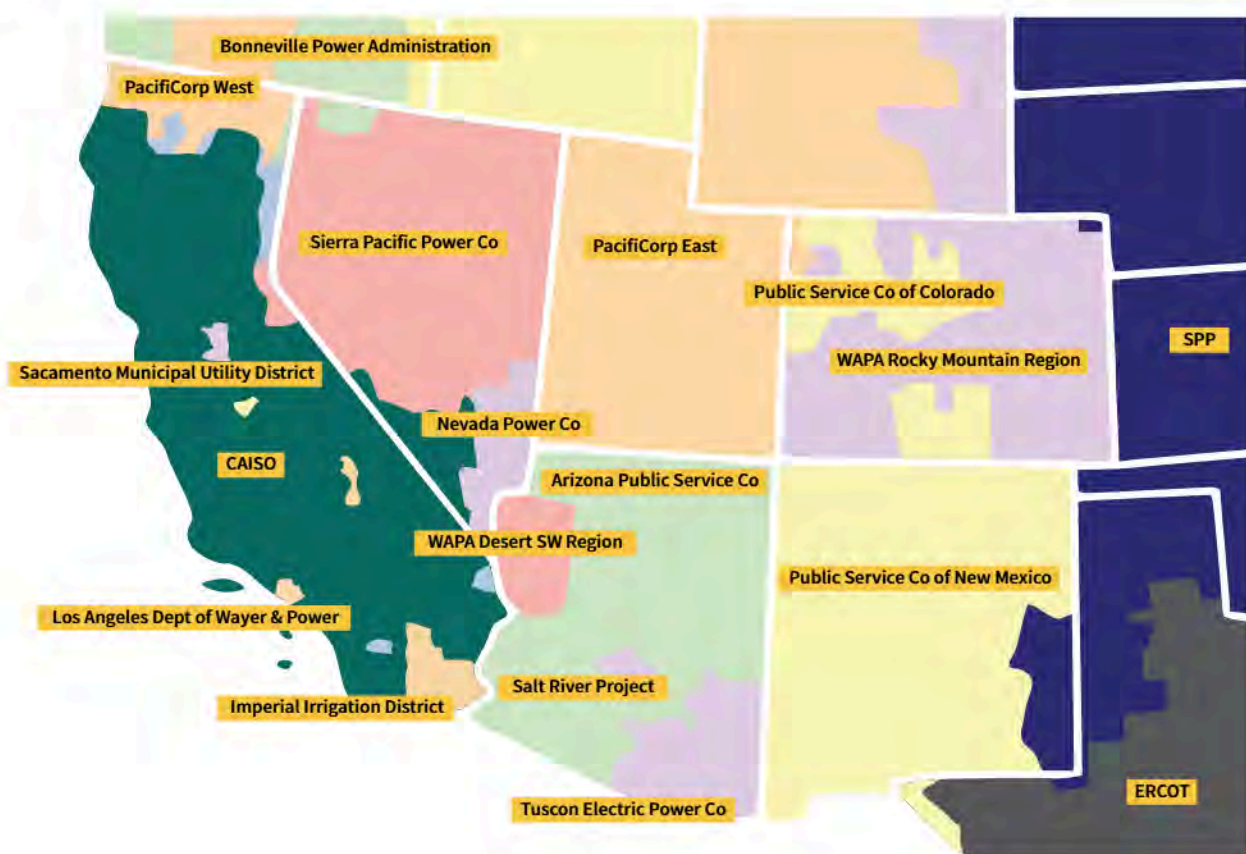
122 Bonneville Power Administration, *BPA Overview*, 45, [https://energy.gov/sites/prod/files/2016/01/f28/0911review\\_ikakoula.pdf](https://energy.gov/sites/prod/files/2016/01/f28/0911review_ikakoula.pdf).

123 Bonneville Project Act, 16 U.S.C. §§ 832-832m (2000).

124 National Energy Board, *Market Snapshot: Which states trade electricity with British Columbia?* (September 2022) <https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/>; National Energy Board, *Market Snapshot: Why Canada is one of the world’s largest electricity consumers* (August 2022), <https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/>

125 The hourly peak demand observed between 2000 and 2020, Based on *FERC Form 714, Annual Electric Balancing Authority Area and Planning Area Report*. Derived from the Balancing Authority Areas within the AZ/NM/SNV NERC subregion, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

**Figure 2-11: Southwest Electric Region**



Source: Hitachi Energy, Velocity Suite

### Supply Resources

The total capacity in the Southwest Electric Region is over 40 GW and is predominately composed of natural gas and coal-fired generators. Hydroelectric, wind, solar, and nuclear capacity account for the majority of the remaining capacity, as shown in the bar chart below.

The majority of generation in the Southwest is produced from natural gas and coal, as demonstrated in the bar chart above. The coal generators are generally located in close proximity to coal mines, resulting in low delivered fuel costs. Some generation is jointly

owned among multiple nearby utilities, including the Palo Verde nuclear plant, a plant with three units totaling approximately 4,000 MW,<sup>126</sup> which has owners in California and the Southwest.<sup>127</sup> The Southwest is also characterized by large amounts of solar capacity, as this region has the highest solar potential in the nation.<sup>128</sup>

### Trading and Market Features

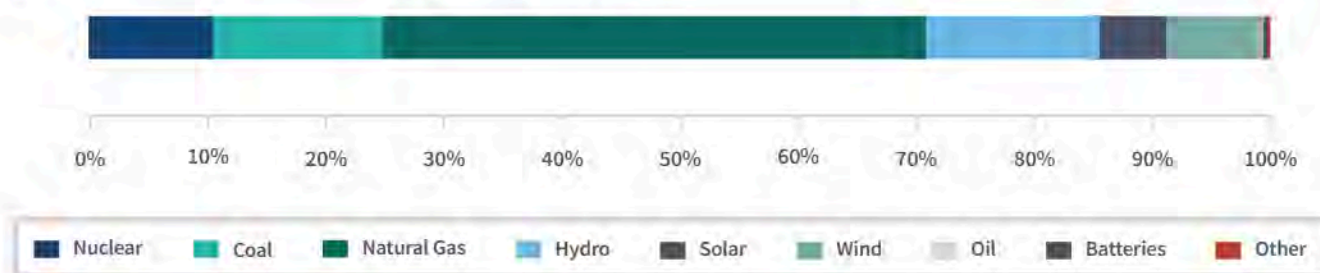
The Southwest region is summer-peaking and experiences peak loads coincident with air conditioning demand. The daily high temperature averages above 100 degrees from June through mid-September in Phoenix.

126 Derived from EIA, *Form EIA-860, 3-1-Generator\_Y2021 Report*, (2021), <https://www.eia.gov/electricity/data/eia860/>.

127 Plant Operating License, Palo Verde, Unit 1, Current Facility Operating License NpF-41, Tech Specs, Revised 08/18/2022, <https://www.nrc.gov/info-finder/reactors/palo1.html>.

128 Western Electricity Coordinating Council, *State of the Interconnection*, at 9 (September 2017), <https://www.wecc.biz/epubs/StateOfTheInterconnection/>.

**Figure 2-12: Southwest Electric Region Capacity Mix**



Source: EIA Form 860-M<sup>129</sup>

However, power prices tend to be the highest when there is also hot weather in Southern California, creating competition for the region's generation resources. The Southwest trading points include Palo Verde, Four Corners, and West Wing. Of these, Palo Verde is the most actively traded location.

## RTO and ISO Markets

Two-thirds of the population of the United States is served by electricity markets run by regional RTOs/ISOs. A key distinction between RTO/ISO markets and vertically integrated utilities, municipal utilities and co-ops is that RTO/ISO markets deliver electricity through competitive market mechanisms coordinated by a non-profit entity over a large geographic footprint. Further, RTOs/ISOs do not own or conduct maintenance on the transmission or other resources involved in providing electric service.

Currently, seven RTO/ISOs operate in the United States, listed below in order of the size of their all-time peak load.<sup>130</sup> FERC regulates all RTOs/ISOs except ERCOT. In addition to operating RTOs/ISOs, SPP and CAISO also operate regional short-term or imbalance energy markets, which, while not RTOs/ISOs, provide markets

for real-time energy sales and purchases. SPP operates the WEIS and CAISO runs the WEIM, which are discussed at the end of the SPP and CAISO sections below.

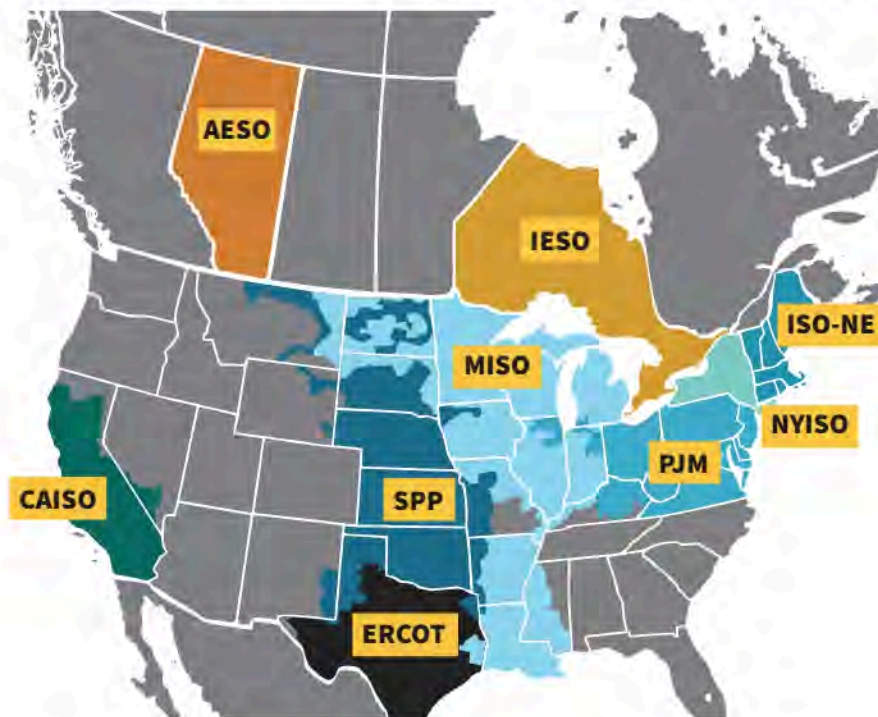
- PJM, 165 GW (summer of 2006)
- MISO, 127 GW (summer of 2011)
- ERCOT, 80 GW (summer of 2022)
- SPP, 53 GW (summer of 2022)
- CAISO, 52 GW (summer of 2022)
- NYISO, 34 GW (summer of 2013)
- ISO-NE, 28 GW (summer of 2006)

Unlike traditional electricity systems, RTOs/ISOs also operate competitive, nondiscriminatory electricity markets, which allow resource owners to offer resources and load-serving entities to submit bids for generation. These markets are the primary mechanism for dispatching resources, managing transmission congestion and pricing electricity. RTOs/ISOs work in conjunction with the resources and transmission-owning resources that participate in the RTO/ISO to maintain reliability. RTOs/ISOs also coordinate the maintenance of generation and transmission systems and oversee a transmission planning process to identify needed upgrades in both the near- and long-term.

129 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (February 2022), <https://www.eia.gov/electricity/data/eia860m/>.

130 For source information on the peak load statistics for PJM Interconnection, Midcontinent ISO, Southwest Power Pool, California ISO, New York ISO, and New England ISO, see the individual region's description later in this chapter. For ERCOT, see *ERCOT, Fact Sheet*, (October 2022), [https://www.ercot.com/files/docs/2022/02/08/ERCOT\\_Fact\\_Sheet.pdf](https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf).

Figure 2-13: North American Regional Transmission Organizations and Independent System Operators



Source: Hitachi Energy, Velocity Suite

## RTO/ISO FEATURES

All RTOs/ISOs function as non-profit entities that operate markets to dispatch and price electricity across a large, defined footprint. To do this, the RTOs/ISOs perform functions such as operating day-ahead and real-time markets, but also perform an array of functions not directly part of the markets, but essential to allow their efficient performance. For example, RTOs/ISOs manage the flow of payments between market participants. The next section discusses markets operated by RTOs/ISOs. The remainder of this section discusses key RTO/ISO support features or functions.

### Governance

RTOs/ISOs, resource owners and operators, investor-owned, public and cooperative utilities, marketers and financial entities participate in the RTO/ISO under a governance structure and rules determined through RTO/ISO-run processes.<sup>131</sup> RTO/ISO governance

typically involves a board of directors and stakeholder committees, which, among other things, review rule revisions. Rules underlying RTO/ISO functions are included in the RTO's/ISO's tariff and are subject to FERC's approval. Details on rule implementation can be found in RTO's/ISO's Business Practice Manuals.

### Financial Policies

Financial settlement is the process through which payments due from customers, and to generators, are calculated. Such settlements are based upon day-ahead schedules, real-time metering, interchange schedules, internal energy schedules, ancillary service obligations, transmission reservations, energy prices, Financial Transmission Rights (FTR) positions, and capacity positions. Each market participant's invoice of charges and credits includes the costs of services used to serve load and the costs for operating the RTO/ISO.

131 Order No. 2000, *Regional Transmission Organizations*, 89 FR 61,285, (December 20, 1999).

Generally, customers receive weekly or monthly invoices stating their charges and credits. Weekly invoices must be settled within a few days of being issued, while monthly invoices must be paid within either one or two weeks, depending on the policies of each RTO/ISO. All payments are made electronically.

While RTO/ISO energy and ancillary service markets operate to price electricity at a level that compensates resources for their energy supply and meet other requirements of their tariffs, instances do occur where additional cost recovery is needed – this is commonly known as uplift. The need for uplift may arise, for example, when unplanned transmission and generation outages occur, resulting in actual operations differing from the assumptions included in the market models underlying the energy and ancillary service markets.<sup>132</sup>

### **Credit Policies**

RTOs/ISOs settle the many financial charges that are paid by, or to, market participants. As RTOs/ISOs are non-profit entities with no financial interest in the markets they operate, any financial shortfall or over-collection goes to the various market participants. To protect the RTO/ISO and its market participants, each RTO/ISO has tariff provisions and other policies to ensure that market participants have the ability to pay, known as credit policies.<sup>133</sup> Defaults by market participants in RTOs/ISOs are rare and the costs have generally been spread across the market. Credit policies contain provisions related to credit evaluations, credit limits, forms of collateral, and the consequences of violations or defaults.

### **Transmission Planning**

RTO/ISOs coordinate transmission planning for their footprint as required under Order 1000, a comprehensive transmission rule issued by FERC in 2011.<sup>134</sup> Each of

the RTO/ISOs has system-wide or regional planning processes that identify transmission system additions and improvements that are needed to keep electricity flowing. Studies are conducted to test the transmission system against mandatory national reliability standards, as well as regional reliability standards. The RTO/ISO transmission planning studies may look 10-15 years into the future to identify transmission overloads, voltage limitations, and other reliability problems. RTO/ISOs then develop transmission plans in collaboration with transmission owners to resolve potential problems that could otherwise lead to overloads and blackouts. This process culminates in one recommended plan for the entire RTO/ISO footprint.

## **RTO/ISO MARKETS AND ASSOCIATED FUNCTIONS**

RTOs/ISOs operate several markets and functions that address the physical supply of electricity and its pricing – energy and capacity markets. To physically provide the supply of electricity at all times in all places, RTOs/ISOs operate energy markets that LSEs use to procure energy and ancillary services. Some RTOs/ISOs also operate capacity markets, which, along with underlying resource adequacy rules, ensure sufficient capacity is available. RTOs/ISOs also operate financial markets associated with the energy markets – financial transmission rights and virtual transactions.

RTOs/ISOs must define rules and operate programs needed to ensure efficient market operations. The operations of the markets are discussed further below. Underlying these market operations are an extensive list of detailed rules and functions. For example, these rules detail what types of resources can participate, at limits on what prices resources can offer, and the operation of an independent market monitoring program:

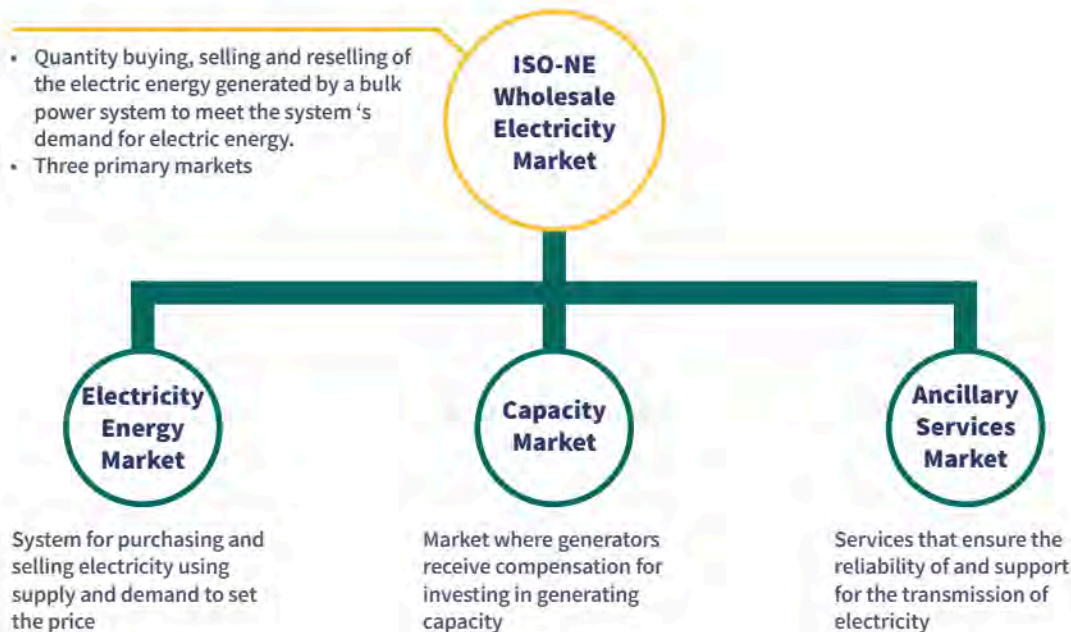
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132 Order No. 844, *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 163 FR 61,041, (April 19, 2018).

133 Order No. 741, *Credit Reforms in Organized Wholesale Electric Markets*, 133 FR 61,060, (October 21, 2010).

134 Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 135 FR 61,051, (July 21, 2011).

**Figure 2-14: ISO-NE Wholesale Electricity Market**



Source: ISO-NE

**Resource Participation** In addition to generation, demand response resources (DR), DER, energy efficiency and batteries may participate in RTO/ISO markets.<sup>135</sup>

**Offer Caps** Each RTO/ISO caps a resource's supply offer at \$1,000. If a resource's costs exceed \$1,000, they may request authority to offer at a higher price that reflects their verified costs. Offers up to \$2,000 may be used by the RTO/ISO to set the locational marginal price.<sup>136</sup>

**Market Monitoring** Each RTO/ISO must have independent market monitors which oversee various aspects of the RTO's/ISO's markets and performance, such as market power mitigation, assessment and referral of market manipulation and assessing and reporting on the competitiveness of market operations.<sup>137</sup>

### Energy Markets

All RTOs/ISOs have day-ahead and real-time markets. The day-ahead market schedules electricity production, ancillary services commitments and consumption before the operating day, whereas the real-time market reconciles any differences between the schedule in the day-ahead market and the real-time conditions. Both the day-ahead and real-time markets reflect reliability criteria and infrastructure conditions, such as transmission topology and limitations, resource outages, and resource operating limits.

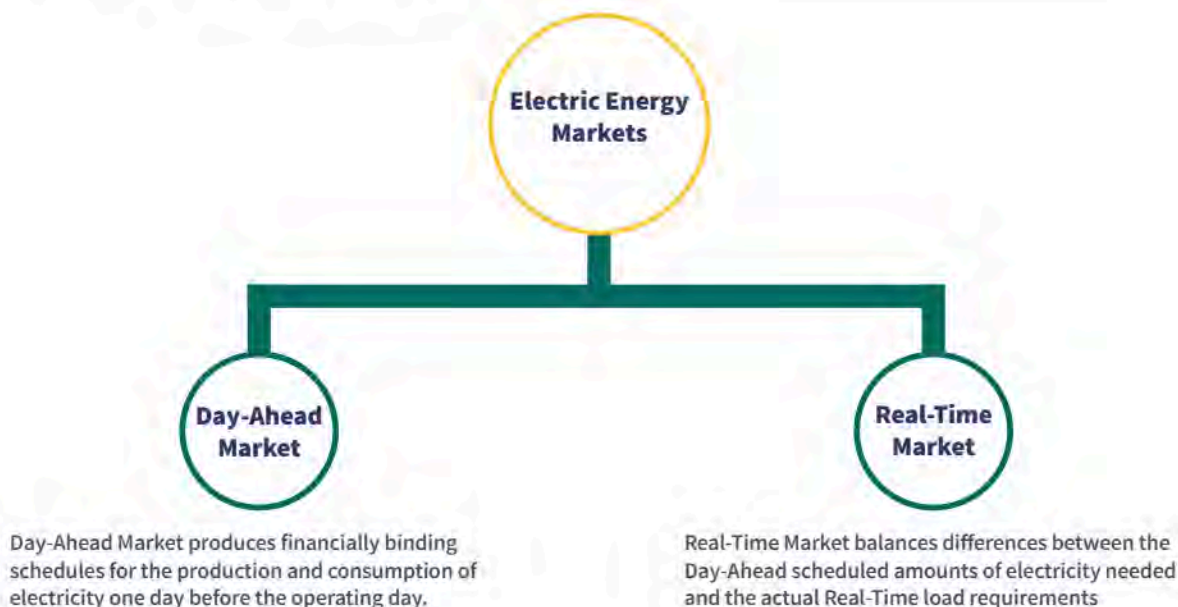
Energy markets operate to match the supply options offered by resource operators to the demand bid in by LSEs and RTO/ISO demand forecasts. The market models select the most economic supply offers available,

<sup>135</sup> Order No. 2222, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 ¶61,247; Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 162 ¶61,127 (2018); Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, 134 ¶61,187, (March 15, 2011).

<sup>136</sup> Order No. 831, *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 ¶61,115, (November 17, 2016).

<sup>137</sup> Order No. 719, *Wholesale Competition in Regions with Organized Electric Markets*, 125 ¶61,071.

**Figure 2-15: ISO-NE Wholesale Electricity Market**



Source: ISO-NE

recognizing physical resource and transmission limitation. The overall market price for electricity is determined by the highest offer accepted. However, transmission limitations may require the market to adjust the offers selected, which can change the price for different locations in the RTO/ISO – the locational marginal price (LMP). The RTO/ISO markets calculate the LMP at each location on the power grid. The LMP reflects the marginal cost of serving load at the specific location, given the set of resources that are being dispatched and the limitations of the transmission system. LMP has three elements: an energy charge, a congestion charge, and a charge for transmission system energy losses.

If there are no transmission constraints, known as transmission congestion, LMPs will not vary significantly across the RTO/ISO footprint. However, when transmission congestion occurs, LMPs will vary across the footprint because operators are not able to dispatch the least-cost generators across the entire region and some more expensive generation must be dispatched to meet demand in the constrained area.

When transmission is constrained, the highest variable

cost unit that must be dispatched to meet load within transmission-constrained boundaries will set the LMP in that area. All sellers receive the LMP for their location and all buyers pay the price for their location.

The primary means used for relieving transmission congestion constraints is by changing the output of generation at different locations on the grid. The market-based LMP sends price signals that reflect congestion costs to market participants. Thus, LMPs take into account both the impact of specific generators on the constrained facility and the cost to change (redispatch) the generation output to serve load. This process is known as security-constrained economic dispatch.

This redispatch could be implemented by using non-market procedures, such as transmission loading relief (TLR). NERC established the TLR process for dealing with reliability concerns when the transmission network becomes overloaded and power flows must be reduced to protect the network. A TLR is used to ration transmission capacity when the demand for transmission is greater than the available transmission capacity (ATC). The rationing is a priority system that cuts power flows

based on size, contractual terms and scheduling.

#### *Day-Ahead Energy Markets*

The day-ahead energy market produces financially binding schedules for the production and consumption of electricity one day before its production and use (the operating day). The purpose of the day-ahead market is to give generators and load-serving entities a means for scheduling their activities with sufficient lead time to procure fuel or bring up resources with longer start times. The day-ahead bids and offers are based on a forecast of loads and are consistent with resources' business strategies.

In day-ahead markets, offers of supply and demand bids are compiled hours ahead of the beginning of the operating day. The RTO/ISO then runs a computerized market model that matches demand and supply throughout the market footprint for each hour of the day. Additionally, the model must account for changing system capabilities that occur, based on weather and equipment outages, transmission and resource capabilities, and the rules and procedures that are used to ensure system reliability.<sup>138</sup> The market rules dictate that generators submit supply offers and that loads submit demand bids to the RTO/ISO by a deadline that is typically in the morning of the day-ahead scheduling. Typically, 95 percent of all load is scheduled in the day-ahead market and the rest is scheduled in real-time. Generation and demand bids that are scheduled in the day-ahead market are settled at the day-ahead market prices.

Inputs into setting a day-ahead market schedule include:

- Generators' offers to sell electricity for each hour
- Load-serving entities' bids to buy electricity for each hour
- Demand-response offers by customers to curtail usage of electricity
- Virtual demand bids and supply offers
- Operational information about the transmission

grid and generating resources, including planned or known transmission and generator outages, the physical characteristics of generating resources including minimum and maximum output levels and minimum run time, and the status of interconnections to external markets.

#### *Real-Time Energy Markets*

The real-time market is used to balance the differences between the day-ahead scheduled amounts of electricity cleared in the day-ahead market and the actual real-time load and supply. The real-time market is run in five-minute intervals and clears a much smaller volume of energy and ancillary services than the day-ahead market (some RTOs/ISOs also run hour-ahead and 15 minutes-ahead of the operating interval). The real-time market also provides supply resources additional opportunities for offering energy into the market. When the real-time generation and load are different from the day-ahead cleared amount, the difference is settled at the real-time price.

Real-time market prices are significantly more volatile than day-ahead market prices. This stems from demand uncertainty, transmission and generator forced outages, and other unforeseen events. Since the day-ahead market generally is not presented with these events, it produces more stable prices than in real-time. Also, because the volumes in the real-time market are much smaller, there is an increased likelihood of supply and demand imbalances, which can lead to both positive and negative price movements.

#### *Ancillary Services*

RTOs/ISOs procure ancillary services, which are described in the Electricity Supply and Delivery Section, through the day-ahead and real-time market dispatch. RTOs/ISOs primarily procure ancillary service through their market mechanisms, although they compensate blackstart and voltage service based on the cost of providing the service (cost-of-service). Changes in the

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<sup>138</sup> In evaluating which generators provide the power to meet hourly load, the market model assesses whether the power flows can travel without exceeding the physical capability of any transmission path. If the model shows such a violation of transmission capability, the combination of assigned generators will be changed in a process known as redispatch.

resources providing supply have necessitated changes in ancillary service procurement and compensation. For example, the advent of faster-ramping resources led to changes in compensation for frequency regulation.<sup>139</sup>

While not an ancillary service, ramping capacity is a service for which some RTOs/ISOs have developed products. The growth of renewable generation has increased the need for generation that can increase its production rapidly to offset swings in generation or load.

#### *Shortage Pricing*

RTO/ISO markets dispatch energy and ancillary services to meet demand and reserve requirements. However, the markets may find that not enough supply is available. If the RTOs/ISOs cannot procure sufficient generation to meet demand and reserve requirements in the real-time market, they trigger shortage pricing<sup>140</sup> to send price signals to incentivize resources to increase the supply offered. Shortage events can be caused by unexpectedly high electric loads, supply disruptions, or both.

The common method that RTO/ISOs employ to implement shortage pricing is through the use of an operating reserve demand curve. The demand curve specifies price levels for the degree of the shortages.<sup>141</sup> The price of the reserves, reflecting shortage as determined by the demand curves, sets the price for ancillary services and energy.

#### *Market Power Mitigation*

RTO/ISO energy and capacity markets are typically competitive, allowing the markets to set the price. However, situations may occur that result in certain resources being essential to serving demand, thus enabling those resources to increase prices in a specific area – in other words, the ability to exercise market power. Typically, this occurs when a transmission

constraint limits the amount of electricity that can flow into an area, rendering generation located inside that area essential to serving that local load. RTOs/ISOs have mechanisms for determining whether such market power may occur, and if appropriate, to mitigate the price at which affected resources may offer their supply. RTO/ISO market power mitigation typically examines whether a resource has the potential to exert market power; whether they actually offer in a way that could be an exertion of market power (conduct test); and whether any potential exertion of market power actually affected the market price (impact test).

### **RTO/ISO Capacity Markets and Resource Adequacy**

RTO/ISOs, like other electric systems, are required to maintain adequate generation and demand-resource capacity to meet load and reliability requirements. LSEs have typically satisfied their reserve obligations with owned generation or bilateral contracts with other suppliers. In general, LSEs are required to procure sufficient capacity to meet their load. Some RTOs/ISOs also have mechanisms through which LSEs can obtain capacity commitments, such as capacity auctions and capacity payments.

Most RTOs/ISOs run a capacity market that allows LSEs to satisfy their reserve obligation. The markets cover short-term capacity, such as a month, season or year. PJM and ISO-NE run capacity auctions up to three years prior to when the capacity is needed. The capacity markets are intended to provide more certainty for investment in new capacity resources while including an opportunity for all resources to recover their fixed costs over time.

Other ISOs/RTOs, such as SPP and CAISO, rely on resource adequacy programs, in which the RTO/ISO determines the capacity each LSE is required to provide

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139 Order No. 755, *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 F.161,064, (October 20, 2011).

140 Order No. 825, *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 155 F.161,276 (June 16, 2016).

141 RTO/ISOs apply shortage pricing in the LMP for all intervals in which the operating software indicates that there is insufficient available energy to provide system or localized demand and reserves. *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 81 Fed. Reg. 42,882 (June 30, 2016), FERC Stats. & Regs. ¶ 31,384 (2016).

at different times of the year. These programs require each LSE to show the RTO/ISO that it has procured the required capacity for different times of the year.

*Special Provisions for Essential Resource Retirements*  
Reliability must-run (RMR) units are generating plants that would otherwise retire but that the RTO/ISO has deemed necessary to ensure reliability. They can also be units that have market power due to their location on the grid. RTO/ISOs enter into cost-based contracts with these generating units and allocate the cost of the contract to transmission customers. In return for these payments to the generator, the RTO/ISO may call on the owner of an RMR generating unit to run the unit for grid reliability. The payment must be sufficient to pay for the cost of owning and maintaining the unit, even if it does not operate. Transmission upgrades can reduce the need for RMR units by increasing generation deliverability throughout the RTOs/ISOs.

### **Financial Transmission Rights**

Financial transmission rights (FTRs) are contracts that give market participants an offset, or hedge, against transmission congestion costs in the day-ahead market.

FTRs were originally developed in part to give native LSEs in the nascent RTOs/ISOs price certainty similar to that available to traditional vertically integrated utilities operating in non-RTO/ISO markets. This practice continues, as FTRs are allocated to load-serving entities, transmission owners, or firm transmission right holders in RTOs/ISOs, typically based on historical usage. Entities that fund the construction of specific new transmission facilities may also be eligible to receive FTRs. The details of the allocations vary by RTO/ISO.

FTRs allow customers to protect against the risk of congestion-driven price increases in the day-ahead market in the RTOs/ISOs. Specifically, FTRs grant their holders the right to day-ahead congestion revenues over specific paths and periods of time. Congestion costs occur as the demand for scheduled power over a transmission path exceeds that path's flow capabilities. This causes the price at the source to decline or the price at the sink to

increase, or both, causing the congestion cost of serving Point B from Point A to increase. By buying an FTR over the path from Point A to Point B, the FTR holder is paid the difference of the congestion price components at the sink and source, thus allowing it to hedge against the congestion costs incurred in the day-ahead market.

FTRs are acquired through allocations and purchases. Purchases take place in the RTO-administered auctions or in a secondary market. Allocations stem from a related product, the auction revenue rights (ARR). ARR provides the firm transmission capacity holders, transmission owners or LSEs with the rights to revenue from the FTR auctions. In general, ARRs are allocated based on historical load served and, in some RTO/ISOs, ARRs can be converted to FTRs. If ARRs are converted to FTRs, the holder receives revenue from congestion. If ARRs are kept as such, the holder receives revenue from the FTR auction.

The main method for procuring FTRs is through an auction, which typically includes an annual (or multiyear) auction of one-year FTRs and monthly (or semiannual) auctions of shorter-term FTRs provided by existing FTR holders or made available by the RTO/ISO. The auctions are scheduled and run by the RTO, which requires bidding parties to post credit to cover the positions taken. FTR auction revenues are used to pay the holders of ARRs and assist the funding of future congestion payments to FTR holders. There is also a secondary market for FTRs (such as PJM's eFTR), but historically only a small number of transactions have been reported.

The quantity of FTRs made available by the RTO/ISO is bounded by the physical limits of the grid, as determined by a simultaneous feasibility test across all potential flowgates. This test is performed by the RTO/ISO prior to making FTRs available at auction and takes into account existing FTR positions and system constraints. The resulting portfolio of FTRs allocated or offered at auction represents an absolute constraint on the size of the net positions that can be held by the market. Participants in FTR auctions can procure counterflow FTRs, which directly offset prevailing flow FTR capacity, thereby allowing the

value at risk on a given path to exceed the physical limits of the line. However, such bids are physically constrained, as the net position held on the path must always conform to the simultaneous feasibility test.

FTRs can also be purchased by a creditworthy entity seeking their financial attributes as a speculative investment. In this regard, FTRs are similar to financial swaps that are executed as a contract for differences between two day-ahead LMPs (swaps are explained in Chapter 5, Trading and Capital Markets). However, FTRs are substantially different from swaps in that the quantity of FTRs is linked to physical constraints in the transmission grid, while the quantity of swaps is not. Further, FTRs are procured by allocation or FTR auction, while swaps are procured through financial over-the-counter markets or exchanges.

All six FERC-jurisdictional RTOs/ISOs trade FTRs or FTR-equivalent products. However, the types and qualities of the rights traded across the organized markets vary, as do the methods used to allocate, auction, and transfer these rights. These attributes of the FTR markets are discussed below.

**Flow Type:** Prevailing Flow and Counterflow. A prevailing flow FTR generally has a source in a historical generation-rich location and a sink that is in a historical load-heavy location. Alternatively, the source of a prevailing flow FTR is on the unconstrained side of a transmission interface and the sink on the constrained side. Auction clearing prices for prevailing flow FTRs are positive. Conversely, a counterflow FTR often has a source in a historical load-heavy location and a sink in a historical generation-rich location. As a result, auction clearing prices for counterflow FTRs are negative; bidders are paid to take the counterflow FTR position.

**Peak Type:** On-peak, Off-peak, 24-hour. FTRs can be purchased for either 16-hour on-peak blocks, 8-hour off-peak blocks or around-the-clock. Only PJM offers all three peak-type products. NYISO offers only the 24-hour product. The other RTO/ISOs offer on-peak and off-peak products.

**Allocated Rights:** The RTO/ISOs allocate transmission rights to transmission owners or load-serving entities within their markets. In PJM, MISO, SPP, and ISO-NE, these are allocated as auction revenue rights (ARRs), which give their holders the right to receive a share of the funds raised during the FTR auctions. CAISO allocates congestion revenue rights (CRR), which provide their holders a stream of payments based on the actual congestion occurring on associated paths. NYISO allocates both auction-based and congestion-based rights through multiple instruments. PJM and MISO allow ARR holders to convert all these rights to FTRs; NYISO allows only a portion of ARR-equivalent instruments to be converted to its version of FTRs, called Transmission Congestion Credits (TCCs). ISO-NE does not allow such conversions, while CAISO's allocation is already in a form equivalent to an FTR. Converted ARRs are fully fungible in PJM, MISO, and NYISO; CAISO only allows the sale of allocated CRRs in its secondary market, and ISO-NE has no converted instruments to sell.

**Auctioned Rights:** All RTOs provide FTRs (or equivalent CRRs or TCCs) for sale to the public through two or more auctions held at various times of the year. The products vary by market and by auction, with some products made available only at specific auctions.

**Secondary Markets:** With the exception of NYISO, each of the markets that auction FTRs also operates a bulletin board or similar venue designed to enable a secondary trading platform for FTRs. However, none of these platforms has had significant volume. NYISO offered to create a bulletin board for its participants, if requested, but received no requests.

### Virtual Transactions

Virtual bids and offers (collectively, virtuals) are a form of financial trading used by market participants to hedge physical positions and by speculative traders to profit from differences between day-ahead and real-time prices. The quantity of MW purchased or sold in the day-ahead market is offset by a sale or purchase of an identical quantity of MW in the real-time, so that the net effect on the market quantity traded is zero. A virtual

trader pays (or is paid) the day-ahead price while being paid (or paying) the real-time price.

Although a trader does not have to deliver power, the transaction is not strictly financial as virtual transactions can set LMPs; the price is applied to physical as well as financial transactions. Virtual transactions can also affect the resource selection in the day-ahead market.

For each hour in the day-ahead market, virtual trades are added to the demand – day-ahead scheduled load – if virtual demand is greater than virtual supply. This has the effect of raising the price in the day-ahead market and, more importantly, increasing the amount of generation resources procured by the RTO/ISO. Since these generation resources will be available to the real-time market, the fact that virtual load does not carry forward into the real-time market will decrease the real-time demand below day-ahead scheduled load, thus placing downward pressure on real-time prices. The placement of virtuals affects the dispatch of physical capacity.

The primary benefits of virtual transactions are achieved through their financial impact on the markets. Virtuals sometimes are referred to as convergence bidding, as a competitive virtual market should theoretically cause the day-ahead and real-time prices to converge in each hour. The convergence of day-ahead and real-time prices within the RTOs/ISOs is intended to mitigate market power and improve the efficiency of serving load.

## ISO-New England (ISO-NE)

### MARKET PROFILE

ISO-NE serves the six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. As the RTO for New England, ISO-NE is responsible for operating wholesale power markets that trade electricity, capacity, transmission congestion

**Figure 2-16: New England Independent System Operator**



Source: Hitachi Energy, Velocity Suite

contracts, and related products, in addition to administering auctions for the sale of capacity.<sup>142</sup> ISO-NE operates the region's high-voltage transmission network and performs long-term planning for the New England system. ISO-NE operates its master control center in Holyoke, Mass.

### Peak Demand

New England's all-time peak demand was 28 GW in summer 2006.<sup>143</sup>

### Imports and Exports

ISO-NE is interconnected with the NYISO, TransEnergie (Québec), and the New Brunswick System Operator and imports around 15 percent of its annual energy needs. New England receives imports from Québec and New

142 ISO-New England Inc. Internal Market Monitor, *An Overview of New England's Wholesale Electricity Markets, A Market Primer* (June 5, 2023), <https://www.iso-ne.com/static-assets/documents/2023/06/imm-markets-primer.pdf>.

143 ISO New England, *Key Grid and Market Stats*, <https://www.iso-ne.com/about/key-stats/>.

Brunswick in most hours, and power flows in alternate directions between New England and New York, depending on market conditions.

### Market Participants

The ISO-NE participants consist of end-users, IOUs, publicly owned utilities, generators, transmission owners, and financial institutions.

### Membership and Governance

ISO-NE is a not-for-profit entity governed by a 10-member, independent, non-stakeholder board of directors. The sitting members of the board elect people to fill board vacancies.

NEPOOL is the principal stakeholder organization for the ISO-NE and is authorized to represent its more than 440 members in proceedings before FERC. It was organized in 1971 and its members include all the electric utilities rendering or receiving services under the ISO-NE Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users, and a merchant transmission provider.

### Transmission Owners

ISO-NE's largest transmission owners include:

- Central Maine Power Company

- Cross Sound Cable Company, LLC
- Emera Maine, Inc.
- Eversource Energy Service Company
- Maine Electric Power Company
- National Grid USA
- NSTAR Electric Company
- The United Illuminating Company
- VT Transco, LLC

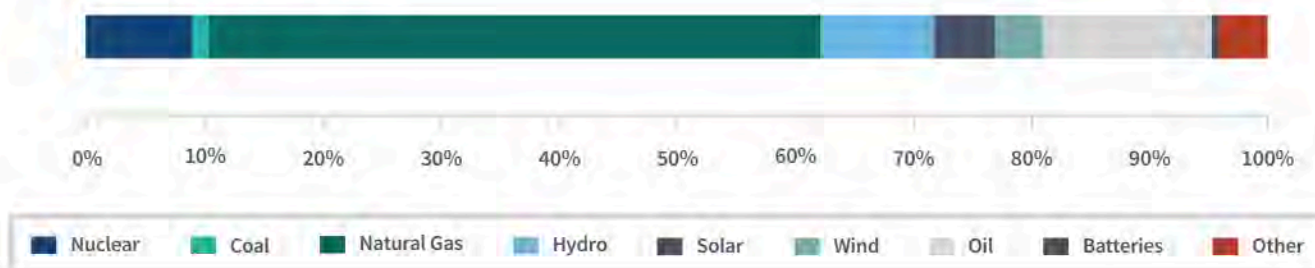
### Chronic Constraints

Overall, transmission upgrades have reduced transmission constraints in ISO-NE. Constraints in ISO-NE may occur in regions affected by intermittent resources (notably wind), or by major interconnections with New Brunswick, Hydro-Quebec, and New York.<sup>144</sup>

### Transmission Planning

Each year, ISO-NE prepares a comprehensive 10-year regional system plan (RSP) that reports on the results of ISO system planning processes. Each plan includes forecasts of future loads (the demand for electricity measured in megawatts) and addresses how this demand may be satisfied by adding supply resources; demand resources, including demand response and energy efficiency; and new or upgraded transmission facilities. The plans also summarize the region's overall needs, as well as the needs in specific areas, and includes solutions and processes required to ensure the

Figure 2-17: ISO-NE Capacity Mix



Source: EIA Form 860-M<sup>146</sup>

144 ISO-New England Internal Market Monitor, 2021 Annual Markets Report (May 26, 2022), <https://www.iso-ne.com/static-assets/documents/2022/05/2021-annual-markets-report.pdf>.

145 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M) (February 2022), <https://www.eia.gov/electricity/data/eia860m/>.

reliable and economic performance of the New England power system.

### Supply Resources

The total capacity in ISO-NE is over 38 GW and is predominately composed of natural gas-fired, oil-fired, and nuclear generators, as shown in the bar chart below. The region has a substantial proportion of oil-fired generation that is a particularly important resource to address potential power plant fuel shortages in the winter months during periods of local natural gas market stress.

### Demand Response

ISO-NE administers the following demand-response programs for the New England wholesale electricity market:

- Real-Time Demand Response Resources (RTDR): These resources are required to respond within 30 minutes of the ISO's instructions.
- Real-Time Emergency Generation Resources that the ISO calls on to operate during a 5-percent voltage reduction that requires more than 10 minutes to implement. They must begin operating within 30 minutes of receiving a dispatch instruction.
- Transitional Price-Response Demand: An optional program that allows market participants with assets registered as RTDRs to offer load reductions in response to day-ahead LMP. The participant is paid the day-ahead LMP for the cleared interruptions, and real-time deviations are charged or credited at the real-time LMP.
- Price Responsive Demand (PRD): In June 2018, ISO New England launched a new PRD structure that fully integrates active demand resources into the regional wholesale electricity marketplace. With PRD, ISO-NE deploys its active demand resources as part of the energy dispatch and reserve-designation process along with generating resources. PRD incorporates demand response into the energy market, the reserves market and the capacity market.<sup>146</sup>

## MARKET FEATURES

### Energy Markets

ISO-NE operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, ISO-NE uses 5-minute intervals. Market participants can offer imports or request exports of electricity from neighboring control areas with at least one hour's notice throughout the day.

### Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. ISO-NE procures and sets prices for ancillary services in the real-time and forward reserve markets.

### Market Power Mitigation

In ISO-NE, market power mitigation is applied for physical withholding, economic withholding, uneconomic production, certain types of virtual transactions and other conduct, if the activity has a material effect on prices or uplift payments. The market monitor uses defined thresholds to identify physical and economic withholding and uneconomic generation. Additionally, defined thresholds determine whether bids and offers would, if not mitigated, cause a material effect on LMPs or uplift charges.

### Capacity Markets

ISO-NE's capacity market is termed the Forward Capacity Market (FCM). The FCM includes annual Forward Capacity Auctions (FCA) where both generator and demand resources offer capacity three years in advance of the period for which capacity will be supplied. The three-year lead time is intended to encourage new resource entry by affording market participants additional time to plan and make decisions relative to the forward market prices. Resources whose capacity clears the FCA acquire capacity supply obligations (CSOs). ISO-NE held its first two FCAs in 2008 for the 2010-11 and 2011-12 delivery years. The first full year of

<sup>146</sup> ISO-NE, *Price-responsive demand explained: Q&A with Henry Yoshimura, ISO Director of Demand Resource Strategy* (June 6, 2018), <http://isonewswire.com/updates/2018/6/6/price-responsive-demand-explained-qa-with-henry-yoshimura-is.html>.

capacity market commitments began on June 1, 2010. The FCA process includes the modeling of transmission constraints to determine if load zones will be import- or export-constrained.

The FCM includes rules known as Pay-for-Performance, which mandate performance-based financial incentives for capacity resources during times of system stress.<sup>147</sup> Under Pay-For-Performance, resource owners are subject to charges or incentive payments, based on performance during shortage conditions. Those resources unable to fulfill their CSOs are penalized and compensate the overperforming resources that relieve the capacity shortfall. ISO-NE additionally requires the owners of capacity resources to offer into the day-ahead and real-time energy markets.

### **Special Provisions for Essential Resource Retirements**

When a resource owner requests to withdraw from the capacity market (termed a delist bid) or to retire the resource (termed a non-price retirement request), the ISO evaluates whether the resource is needed for reliability, such as when a resource's withdrawal could lead to a violation of a reliability requirement, such as inadequate reserve margins or a loss of electric system stability.

In New England, the resource owner has the option to retire the unit or continue to operate it while the ISO works with regional stakeholders to find alternate supply or engineering solutions that could allow the resource to retire and still maintain grid reliability. Alternative solutions might include obtaining emergency sources of generation or more expensive generation from outside the region. If no other alternative is available, the ISO may compensate the unit through certain payment provisions of the capacity market or by entering into a

cost-of-service agreement with the resource owner while other options are pursued.

### **Financial Transmission Rights**

New England FTRs are monthly and annual products that provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead energy market. An FTR is an instrument that entitles the FTR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pairs of locations on the grid. The FTR also requires its holder to pay a charge for those hours when congestion occurs in the opposite direction of the selected source-and-sink pair. The RTO holds FTR auctions to allow market participants the opportunity to acquire FTRs or to sell FTRs they currently hold. In New England, ARRs represent the right to receive revenues from the FTR auctions. ISO-NE allocates ARRs to both LSEs, in relation to historical load, and to entities who make transmission upgrades that increase the capability of the transmission system.

### **Virtual Transactions**

New England's market includes a virtual transaction feature, as generally described in the Virtual Transactions part of the RTO/ISO Features section.

### **Credit Requirements**

ISO-NE's tariff includes credit requirements for participants that assist in mitigating the potential effects of defaults that would otherwise be borne among all market participants. ISO-NE assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. ISO-NE then establishes a credit limit for each market participant in accordance with tariff formulas that include various creditworthiness-related specifications, such as tangible net worth and total amounts due to the ISO-NE market.

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<sup>147</sup> ISO-NE's Pay-For-Performance rules became effective June 1, 2018, for Forward Capacity Auction 9. ISO-NE, Internal Market Monitor, *2017 Annual Markets Report*, at 138 (2018), <https://www.iso-ne.com/static-assets/documents/2018/05/2017-annual-markets-report.pdf>.

**Figure 2-18: New York Independent System Operator**



Source: Hitachi Energy, Velocity Suite

## New York Independent System Operator (NYISO)

### MARKET PROFILE

The NYISO footprint covers the entire state of New York. Prior to restructuring of the electric industry in the 1990s, New York's private utilities and public power authorities owned and operated New York's electric system. Operation of the electric grid was coordinated by a voluntary collaboration of the utilities and power authorities known as the New York Power Pool (NYPP). The creation of the NYISO was authorized by FERC in 1998. The formal transfer of the NYPP's responsibilities to the NYISO took place on Dec. 1, 1999. NYISO operates its system from control centers in Rensselaer, NY, and Guilderland, NY.

NYISO is responsible for operating wholesale power markets that trade electricity, capacity, transmission congestion contracts, and related products, in addition to administering auctions for the sale of capacity. NYISO operates New York's high-voltage transmission network and performs long-term planning. NYISO also serves as the reliability coordinator for its footprint.

### Peak Demand

NYISO's all-time peak demand was 34 GW in summer 2013.<sup>148</sup>

### Imports and Exports

NYISO imports and exports energy through interconnections with ISO-NE, PJM, TransEnergie (Quebec) and Ontario.

### Market Participants

NYISO's market participants include generators, transmission owners, financial institutions, traditional local utilities, electric co-ops, and industrials.

### Membership and Governance

NYISO is governed by an independent 10-member board of directors, ISO management, and the business issues and operating committees. Each committee oversees its own set of working groups or subcommittees. These committees comprise transmission owners, generation owners and other suppliers, consumers, public power, and environmental entities. Tariff revisions on market rules and operating procedures filed with FERC are largely developed through consensus by these committees. The members of the board, as well as all employees, must not be directly associated with any market participant or stakeholder.

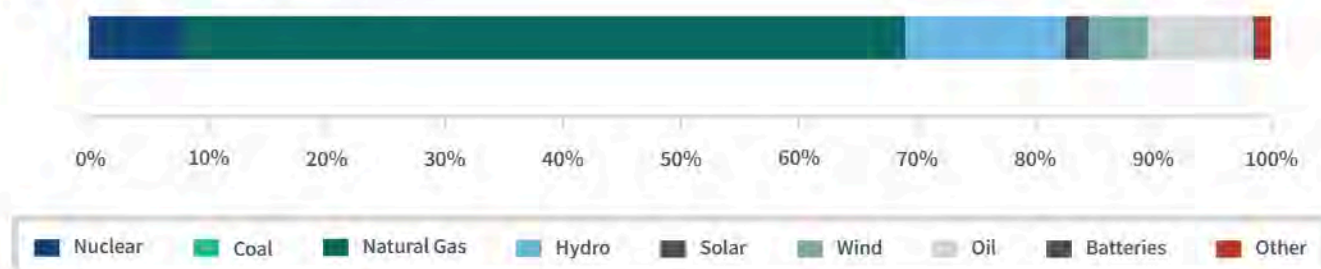
### Transmission Owners

NYISO's largest transmission owners include:

- Central Hudson Gas & Electric Corp.
- Consolidated Edison Co. of New York
- Long Island Power Authority (LIPA)

148 New York Independent System Operator, Gold Book, 2022 Load & Capacity Data Report 67 (April 2022), <https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf/cd2fb218-fd1e-8428-7f19-df3e0cf4df3e.pdf>.

**Figure 2-19: NYISO Capacity Mix**



Source: EIA Form 860-M<sup>149</sup>

- New York Power Authority (NYPA)
- New York State Electric and Gas Corp. (NYSEG)
- National Grid
- Orange & Rockland Utilities
- Rochester Gas and Electric Corp.

### Chronic Constraints

The chronic transmission constraints in NYISO are in the southeastern portion of the state, leading into New York City and Long Island. As a result of their dense populations, New York City and Long Island are the largest consumers of electricity. Consequently, energy flows from the west and the north towards these two large markets, frequently requiring transmission facilities to operate near their limits. This results in transmission constraints in several key areas, often resulting in higher prices in the New York City and Long Island markets.

### Transmission Planning

NYISO conducts a biennial transmission planning process with stakeholders that includes both short-term and long-term projects as part of its Comprehensive System Planning Process. This work evaluates the adequacy and security of the bulk power system in New York over a ten-year study period. Reliability needs are addressed through the development of a reliability plan. Planning focuses on congestion on the bulk power system and possible projects to alleviate the congestion.

A component of NYISO’s transmission planning includes evaluating proposals to meet transmission needs driven by public policy requirements identified by the New York Public Service Commission.

### Supply Resources

The total capacity in NYISO is over 43 GW and is predominately composed of natural gas-fired, hydroelectric, nuclear and oil-fired generators, as shown in the bar chart below. The region’s hydroelectric capacity is particularly important and includes the Niagara Falls and St. Lawrence facilities.

### Demand Response

NYISO has four demand-response programs: the emergency demand-response program (EDRP), the installed capacity (ICAP) special case resources program (SCR), the Day-Ahead Demand-Response Program (DADRP) and the Demand-Side Ancillary Services Program (DSASP).

Both the emergency and special case programs can be deployed in energy shortage situations to maintain the reliability of the bulk power grid. The participants in these programs are paid by NYISO for reducing energy consumption when asked to do so and reductions are voluntary for EDRP participants. However, SCR participants are required to reduce power usage as part of their agreement and are compensated for this obligation.

149 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), <https://www.eia.gov/electricity/data/eia860m/>.

NYISO's DADRP program allows energy users to bid their load reductions into the day-ahead market and offers that are determined to be economic are paid the market clearing price. Under day-ahead demand-response, flexible loads may effectively increase the amount of supply in the market and moderate prices.

The DSASP provides retail customers that can meet telemetry and other qualifications with the ability to bid their load curtailment capability into either the day-ahead market or real-time market to provide reserves and regulation service. Accepted offers are paid the market clearing price for the supplied reserves or regulation services.

## **MARKET FEATURES**

### **Energy Markets**

NYISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, NYISO uses 5-minute intervals. Market participants can offer imports or request exports of electricity from neighboring control areas with at least one hour's notice throughout the day. NYISO refers to LMPs as locational-based marginal prices, or LBMPs.

NYISO's real-time market also offers an hour-ahead feature. The hour-ahead market allows buyers and sellers of electricity to balance unexpected increases or decreases of electricity consumption after the day-ahead market closes. Bids and offers are submitted an hour ahead of time and prices are set based on those bids and offers, generally for use in matching generation and load requirements, but those prices are advisory only. Hour-ahead scheduling is completed at least 45 minutes prior to the beginning of the dispatch hour after NYISO reviews transmission outages, the load forecast, reserve requirements and hour-ahead generation and firm transaction bids, among other things.

### **Ancillary and Other Services**

NYISO co-optimizes ancillary services with the energy through its markets. Operating reserves and regulation are typically provided by generators, but NYISO also

allows demand-side providers to participate in these markets.

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load. RTOs procure or direct the supply of ancillary services to maintain the reliability of the transmission system.

### **Market Power Mitigation**

ISO-NE conducts automatic market power mitigation in its day-ahead and real-time markets. This automated mitigation performs conduct and impact tests and applies mitigation where it deems appropriate. The categories of conduct that may warrant mitigation by NYISO include physical withholding, economic withholding, and uneconomic production by a generator or transmission facility to obtain benefits from a transmission constraint. NYISO does not impose mitigation unless the conduct causes or contributes to a material change in prices, or substantially increases guarantee payments to participants.

Generators in New York City are subject to automated market power mitigation procedures because New York City is frequently separated by transmission congestion from other parts of New York. Additionally, generators in New York City have been deemed to have market power. These automated procedures determine whether any day-ahead or real-time energy bids, including start-up cost bids and minimum generation bids, but excluding ancillary services bids, exceed the tariff's thresholds for economic withholding. The protocols also determine whether such bids would cause material price effects or changes in guaranteed payments. If these two tests are met, mitigation is imposed automatically, and the applicable reference level is substituted for the entity's actual bid to determine the clearing price.

### **Capacity Markets**

NYISO's capacity market requires LSEs to procure capacity through installed-capacity (ICAP) auctions, self-supply or bilateral arrangements based on their forecasted peak

load plus a margin. New York has capacity requirements for four zones: New York City, Long Island, Lower Hudson Valley, and New York-Rest of State. NYISO conducts auctions for three time periods: the capability period auction (covering six months), the monthly auction and the spot market auction. The resource requirements do not change in the monthly auctions and spot market auctions relative to the capability period auction. The shorter monthly auctions are designed to account for incremental changes in LSEs' load forecasts.

Under the NYISO capacity auction rules, entities that offer capacity into an auction that is subsequently purchased by load are required to offer that amount of capacity into the day-ahead energy market. This rule ensures that capacity sold through the capacity auctions is actually delivered into the market.

Capacity for New York City is subject to offer caps and floors. Offer caps in New York City are based on the projected clearing price for capacity in the spot market.<sup>150</sup> Capacity from generators within New York City must be offered in each ICAP spot market auction, unless that capacity has been exported out of New York or sold to meet ICAP requirements outside New York City.<sup>151</sup>

### **Special Provisions for Essential Resource Retirements**

Generation owners within New York that seek to retire or suspend a generator must first obtain approval from state regulators. After an assessment, if the generator is found to be necessary for reliability purposes, the local transmission owner can be compelled to reach a contract with the generator that includes compensation

to support continued operation of the plant until the reliability need is resolved.

### **Financial Transmission Rights**

The NYISO refers to FTRs as Transmission Congestion Contracts (TCCs). A TCC is an instrument that entitles the holder to a payment for the costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations (or nodes) on the grid. The TCC also requires its holder to pay a charge for those hours when congestion is in the opposite direction of the selected source-and-sink pair. The payment, or charges, are calculated relative to the difference in congestion prices in the day-ahead market across the specified FTR transmission path.

### **Virtual Transactions**

NYISO's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual trading in NYISO takes place on a zonal level, not a nodal level.

### **Credit Requirements**

NYISO's tariff includes credit requirements that assist in mitigating the effects of defaults that would otherwise be borne among all market participants. NYISO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. NYISO must review the entity's request relative to various creditworthiness-related specifications such as investment grade or equivalency rating and payment history.

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150 New York Independent System Operator, Inc., *NYISO MST - Market Administration and Control Area Services Tariff (MST) - 23MST Att H - ISO Market Power Mitigation Measures - 23.2 MST Att H Conduct Warranting Mitigation at 625* (accessed October 6, 2022), <https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf>; New York Independent System Operator, Inc., *NYISO MST - Market Administration and Control Area Services Tariff (MST) - 23 MST Att H - ISO Market Power Mitigation Measures - 23.4.5 MST Att Installed Capacity Market Mitigation Measures - 23.4.5.2 MST Att H at 705* (accessed October 6, 2022), <https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf>.

151 New York Independent System Operator, Inc., *NYISO MST - Market Administration and Control Area Services Tariff (MST) - 23 MST Att H - ISO Market Power Mitigation Measures - 23.4.5 MST Att Installed Capacity Market Mitigation Measures - 23.4.5.4 MST Att H at 708* (accessed October 6, 2022), <https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf>.

# PJM

## MARKET PROFILE

PJM centrally dispatches generation and coordinates the movement of wholesale electricity in all or part of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia. PJM operates two fully functional dispatch centers at Valley Forge and Milford, Pennsylvania. The control rooms operate simultaneously with parallel operations. PJM operates a competitive wholesale electricity market and manages the reliability of its transmission grid. PJM provides open access to the transmission system it manages and performs long-term planning. PJM's markets include energy (day-ahead and real-time), capacity and ancillary services.

PJM was founded in 1927 as a power pool of three utilities serving customers in Pennsylvania and New Jersey. In 1956, with the addition of two Maryland utilities, it became the Pennsylvania-New Jersey-Maryland Interconnection, or PJM. PJM became a fully functioning ISO in 1996 and, in 1997, it introduced markets with bid-based pricing and locational market pricing. PJM was designated an RTO in 2001.

### Peak Demand

PJM's all-time peak demand was 165.6 GW in summer 2006.<sup>152</sup>

### Imports and Exports

PJM has interconnections with MISO and the NYISO. PJM also has direct interconnections with TVA, Progress Energy Carolinas and the VACAR, among other systems. PJM market participants import energy from, and export energy to, external regions continuously. PJM is a primarily a net exporter of electricity, but occasionally is a net importer during periods of system stress.

### Market Participants

PJM's market participants include power generators,

Figure 2-20: The PJM Interconnection



Source: Hitachi Energy, Velocity Suite

transmission owners, electric distributors, power marketers, large consumers, and financial traders.

### Membership and Governance

PJM has a two-tiered governance model consisting of a board of managers and the members committee. PJM is governed by a 10-member board, nine of whom PJM members elect. The board appoints the tenth, the president and CEO, to supervise day-to-day operations. The board is generally responsible for oversight of system reliability, operating efficiency and short- and long-term planning. The board ensures that no member or group of members exerts undue influence. The members committee, which advises the board, is composed of five voting sectors representing power generators, transmission owners, electric distributors, power marketers and large consumers.

### Transmission Owners

PJM transmission owners eligible to vote in PJM

152 PJM Interconnection, PJM 2021 Annual Report, Summer Performance by the Numbers, <https://services.pjm.com/annualreport2021/operations/>.

stakeholder proceedings include:

- Appalachian Power Company, AEP Subsidiary<sup>153</sup>
- AMP Transmission, LLC
- Dayton Power & Light Company, AES Subsidiary
- Duke Energy Business Services, LLC<sup>154</sup>
- Duquesne Light Company
- East Kentucky Power Cooperative, Inc.
- Exelon Business Services Company, LLC<sup>155</sup>
- ITC Interconnection LLC
- Linden VFT LLC
- Monongahela Power d/b/a Allegheny Power, First Energy Subsidiary<sup>156</sup>
- Neptune Regional Transmission System, LLC<sup>157</sup>
- PPL Electric Utilities Corporation, d/b/a PPL Utilities<sup>158</sup>
- Public Service Electric and Gas Company
- Rockland Electric Company
- Virginia Electric and Power Company

### Chronic Constraints

The most severe constraints occur on 230 kV transmission facilities moving power south from Pennsylvania and New Jersey to Maryland, Delaware, and Virginia. Local congestion also occurs on low-voltage lines near load centers in northern Illinois, New Jersey, eastern Pennsylvania, central and eastern Maryland, northern Virginia, the District of Columbia, and Delaware.

### Transmission Planning

PJM's Regional Transmission Expansion Plan identifies transmission system additions and improvements needed to keep electricity flowing within PJM. Studies are conducted to test the transmission system against

national and regional reliability standards. These studies look forward to identify future transmission overloads, voltage limitations, and other reliability standards violations. PJM then develops transmission plans to resolve violations that could otherwise lead to overloads and blackouts.

### Supply Resources

The total capacity in PJM is over 219 GW and is predominately comprised of natural gas, coal, and nuclear generators, as shown in the bar chart below. Much of PJM's gas-fired capacity is located near the Marcellus and Utica shale formations. Of note, 40.6 gigawatts of coal-fired capacity are projected to retire in PJM between 2011 and 2026.<sup>159</sup>

### Demand Response

End-use customers providing demand response have the opportunity to participate in PJM's energy, capacity, synchronized reserve, and regulation markets. PJM's demand response programs can be grouped into emergency or economic programs. The emergency program compensates end-use customers who reduce their usage during emergency conditions on the PJM system. Participation in the emergency program may be voluntary or mandatory and payments may include energy payments, capacity payments or both.

The economic program allows end-use customers to reduce electricity consumption in the energy markets and receive a payment when LMPs are high. Under this program, all hours are eligible and all participation is voluntary. Participation in the program takes three forms: submitting an offer into the day-ahead market

153 Transmission Companies represented: AEP Appalachian Transmission, AEP Energy Partners, AEP Energy, AEP Indiana Michigan Transmission, AEP Kentucky Transmission, AEP Ohio Transmission, AEP West Virginia Transmission, Appalachian Power, Indiana Michigan Power, Kentucky Power, Kingsport Power, Ohio Power, Ohio Valley Electric, PATH West Virginia Transmission, Transource Energy, Wheeling Power.

154 Transmission Companies represented: Duke Energy Kentucky, Duke Energy Ohio.

155 Transmission Companies represented: Commonwealth Edison, PECO Energy, Baltimore Gas and Electric.

156 Transmission Companies represented: American Transmission Systems, Jersey Central Power & Light, Mid-Atlantic Interstate Transmission, PATH Allegheny Transmission, Potomac Edison, Trans-Allegheny Interstate Line, West Penn Power.

157 Transmission Companies represented: Hudson Transmission Partners.

158 Transmission companies represented: Louisville Gas and Electric, Kentucky Utilities.

159 Monitoring Analytics, *2022 Quarterly State of the Market Report, January Through June*, Section 12, p. 673 ([https://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2022/2022q2-som-pjm-sec12.pdf](https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022q2-som-pjm-sec12.pdf)).

**Figure 2-21: PJM Capacity Mix**



Source: EIA Form 860-M<sup>161</sup>

that clears; submitting an offer into the real-time market that is dispatched; and self-scheduling load reductions while providing notification to PJM. End-use customers participate in demand response in PJM through members called curtailment service providers who act as agents for the customers. Curtailment service providers aggregate the demand of retail customers, register that demand with PJM, submit the verification of demand reductions for payment by PJM and receive the payment from PJM.

## MARKET FEATURES

### Energy Markets

Energy Markets: PJM operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, PJM uses 5-minute intervals. Generators that are available but not selected in the day-ahead scheduling may alter their offers for use in the real-time market during the generation rebidding period from 4 p.m. to 6 p.m.; otherwise, their original day-ahead market offers remain in effect for the real-time market.

### Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. PJM procures most ancillary services via its energy markets. Blackstart service and reactive power are compensated on a cost-of-service basis.

### Market Power Mitigation

PJM caps offers for any hour in which there are three or fewer generation suppliers available for redispatch that are jointly pivotal, meaning they have the ability to increase the market price above the competitive level. This is called the Three Pivotal Supplier Test. When this occurs, generator offers are adjusted to price levels reflecting short-run marginal cost.

### Capacity Markets

PJM's capacity market is called the Reliability Pricing Model (RPM). The RPM market was implemented in 2007 and is designed to ensure the future availability of capacity resources, including demand-resources and energy-efficiency resources that will be needed to keep the regional power grid operating reliably. The RPM market design is based on three-year, forward-looking annual obligations for locational capacity, under which supply offers are cleared against a downward-sloping demand curve, called the variable resource requirement (VRR) curve. The VRR curve establishes the amount of capacity that PJM requires its LSE customers to purchase, and the price for that capacity, in each capacity zone (locational deliverability area or LDA). Under RPM, when an LDA is transmission-constrained in the auction (limited in the amount of generation that can be imported into those areas), capacity prices generally rise in that area relative to the overall PJM footprint.

160 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), <https://www.eia.gov/electricity/data/eia860m/>.

Annual auctions are referred to as Base Residual Auctions (BRA). LSEs that are able to fully supply their own capacity needs can choose not to participate in the auctions. The largest amounts of capacity in PJM are procured through the BRA, with lesser quantities procured through self-supply and contracted (bilateral) resources.

Market power mitigation in PJM's capacity market includes rules delineating a must-offer requirement, offer caps, minimum offer prices, exceptions for competitive entry, among others. Demand resources and energy efficiency resources may be offered into RPM auctions and receive the clearing price without mitigation.

Specific RPM rules, termed Capacity Performance, provide performance incentives for power plants, demand response, and energy efficiency resources to provide electricity at peak demand regardless of extreme weather events and system emergencies. Capacity Performance rules provide performance bonus payments for resources that over-perform during system emergencies, and severe financial penalties for resources that do not perform during such events.

Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement option. The fixed resource option allows LSEs to meet their supply obligation outside PJM's capacity market, using, for example, resources they own.<sup>161</sup> Intermittent and capacity storage resources, including hydro, and demand response and energy efficiency, are also exempt from must-offer requirements. An administratively determined demand curve defines scarcity pricing levels and, with the supply curve derived from capacity offers, determines market prices in each BRA. Participation by load-serving entities is mandatory, except for those entities that elect the fixed resource requirement option. Also, any generator that has a commitment from the capacity market must submit an offer into the day-ahead energy market.

## Special Provisions for Essential Resource Retirements

A generator owner who wishes to retire a unit must request permission from PJM to deactivate the unit at least 90 days in advance of the planned date. The request includes an estimate of the amount of project investment necessary to keep the unit in operation. PJM, in turn, analyzes if the retirement would lead to a reliability issue. Additionally, PJM estimates the period of time it would take to complete transmission upgrades necessary to alleviate the reliability issue.

If PJM requests the unit to operate past the desired deactivation date, the generator owner may file with FERC for cost recovery associated with operating the unit until it may be deactivated. Alternatively, the owner may choose to receive avoided cost compensation calculated according to PJM's tariff.

## Financial Transmission Rights

PJM conducts auctions for selling and buying FTRs made available for the PJM transmission system. Proceeds from the auctions are paid to Auction Revenue Right (ARR) holders, where the ARRs are allocated to firm transmission service customers. PJM conducts its auctions on a long-term, annual, and monthly basis. In PJM, market participants are able to acquire financial transmission rights in the form of options or obligations. The RTO includes a secondary market for its FTRs, which facilitates bilateral trading of existing FTRs between PJM members through an internet-based computer application.

## Virtual Transactions

PJM's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. In addition to the types of transaction discussed above, PJM offers Up to Congestion (UTC) transactions, a spread bid. In a UTC transaction, a market participant submits an offer to simultaneously inject energy at a specified source and withdraw the same megawatt

161 PJM, *Securing Fixed Resources*, (accessed December 2, 2022), <https://pjm.com/-/media/about-pjm/newsroom/fact-sheets/securing-resources-through-fixed-resource-requirement-fact-sheet.ashx>.

quantity at a specified sink in the day-ahead market and specifies the maximum difference in locational marginal prices (LMP) at the transaction's source and sink that the market participant is willing to pay. PJM accepts the bid if the day-ahead LMP differential, i.e., the difference in day-ahead LMPs at the sink and the source, does not exceed the participant's UTC transaction bid. UTC positions are liquidated in the real-time energy market.

### Credit Requirements

PJM's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. The RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

## Midcontinent Independent System Operator (MISO)

### MARKET PROFILE

MISO operates the transmission system and a centrally dispatched market in portions of 15 states in the Midwest and the South, extending from Michigan and Indiana to Montana and from the Canadian border to the southern areas of Louisiana and Mississippi. The system is operated from three control centers: Carmel, Indiana; Egan, Minnesota; and Little Rock, Arkansas. MISO also serves as the reliability coordinator for additional systems outside of its market area, primarily to the north and northwest of the market footprint.

MISO was not a power pool before organizing as an ISO in December 2001. It began market operations in April 2005.

Figure 2-22: Midcontinent Independent System Operator



Source: Hitachi Energy, Velocity Suite

In January 2009, MISO implemented a market redesign that added auctioned and optimized ancillary services along with energy. As part of the market update, MISO combined its 24 separate balancing areas into a single balancing area. In 2013, the RTO began operations in the MISO South region, including the utility footprints of Entergy, Cleco, and South Mississippi Electric Power Association, among others, in parts of Arkansas, Mississippi, Louisiana, and Texas.

### Peak Demand

MISO's all-time peak demand was 127 GW in summer 2011.<sup>162</sup>

### Imports and Exports

MISO has interconnections with the PJM and SPP RTOs. It is also directly connected to Southern Company, TVA, the electric systems of Manitoba and Ontario, and several smaller systems. MISO is a net importer of power overall, but the interchange with some areas can flow

162 MISO, Corporate Fact Sheet, at 1 (June 2022), <https://www.misoenergy.org/about/media-center/corporate-fact-sheet>.

in either direction, depending on the relative loads and prices in the adjoining regions. Manitoba Hydro supplies a large part of MISO's load with its excess capacity, particularly in the summer.

### Market Participants

MISO includes approximately 56 transmission owners, whose assets define the MISO market area. MISO's market participants include generators, power marketers, transmission-dependent utilities and load-serving entities.<sup>163</sup>

### Membership and Governance

An independent board of directors of ten members, including the CEO, governs MISO. Directors are elected by the MISO membership from candidates provided by the board.<sup>164</sup>

MISO relies upon a stakeholder process that works to find collaborative solutions to problems faced by the RTO. These entities have an interest in MISO's operation and include state regulators, consumer advocates, transmission owners, independent power producers, power marketers and brokers, municipal and cooperative utilities and large-volume customers.

### Transmission Owners

MISO's largest transmission owners include:

- American Transmission Co.
- Ameren (Missouri and Illinois)
- American Transmission Systems
- Duke
- Cleco
- Entergy
- Indianapolis Power and Light
- ITC
- Michigan Public Power Agency
- NSP Companies (Xcel)
- Northern Indiana Public Service Co.

- Otter Tail Power
- MidAmerican Energy

### Chronic Constraints

MISO has certain pathways that are more likely to become congested, but the likelihood and pattern of congestion in any area is subject to weather patterns, wind production, and interchange with external regions. When load is high in the eastern part of MISO and to the east in PJM, constraints occur on pathways from the Minnesota and Wisconsin areas through Chicago and across Indiana. A particular congestion point with this pattern is northern Indiana. When colder weather occurs in Minnesota and the Dakotas, there is often congestion in the northern direction, particularly in Iowa. Higher wind production can cause localized constraints in some areas and can cause congestion in pathways from southern Minnesota and western Iowa moving eastward. New Orleans and East Texas are two constrained areas in MISO South. Additionally, constraints frequently arise between MISO Midwest and MISO South.

### Transmission Planning

The main vehicle MISO uses for transmission planning is the MISO Transmission Expansion Plan developed by the MISO planning department in collaboration with transmission owners and other stakeholders who form the planning advisory committee. The plan is updated annually. Once approved by the board, the plan becomes the responsibility of the transmission owners.

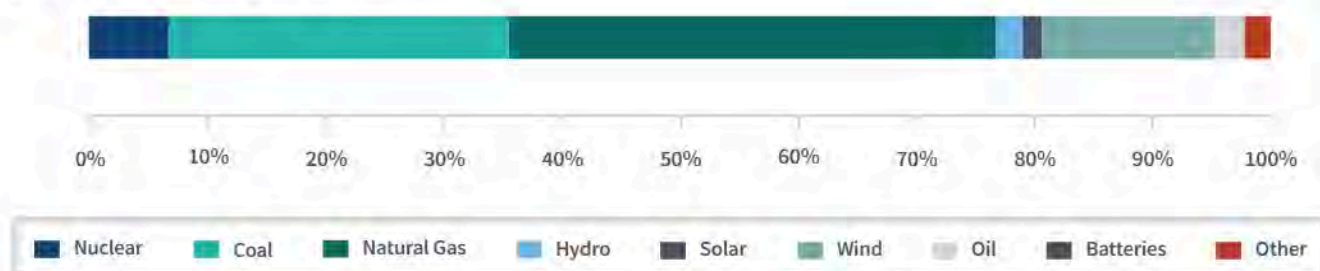
### Supply Resources

The total capacity in MISO is over 197 GW and is predominately composed of coal and natural gas-fired generators, providing roughly 70 percent of the total capacity combined, as shown in the bar chart below. Nuclear and wind are also important resources for the region.

163 *Id.*

164 MISO, *Principals of Corporate Governance*, at 3, <https://cdn.misoenergy.org/Principles%20of%20Corporate%20Governance110859.pdf>.

**Figure 2-23: MISO Capacity Mix**



Source: EIA Form 860-M<sup>165</sup>

## Demand Response

MISO has more than 12.2 GW of demand response resources, including behind-the-meter generation. A number of these resources are operated through local utility programs and are not under the direct control of MISO. MISO has provisions allowing demand-side resources to participate in the energy and reserve markets, but participation is a small part of demand response. Some of the demand response under MISO's direct control is only available under emergency conditions.<sup>166</sup>

## MARKET FEATURES

### Energy Markets

MISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. MISO's real-time market operates for 5-minute intervals.

### Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. MISO procures ancillary services via the co-optimized energy and ancillary services market.

In addition to ancillary services, MISO has implemented a ramping product that provides capacity that can

increase output rapidly to help offset shifts in generation or load, known as the Ramp Capability Product (RCP).

### Market Power Mitigation

When congestion occurs, there may be limits on the number of generators that can satisfy load in some areas, so that they may be able to exercise market power. In response, MISO may impose mitigation for those generators whose offers are significantly higher than their costs and have a significant impact on one or more LMPs. When these conditions are met, MISO reduces the generator's offer to an offer that is consistent with a competitive result.

### Capacity Markets

MISO maintains an annual capacity requirement on all LSEs based on the load forecast plus reserves. LSEs are required to specify to MISO what physical capacity, including demand-side resources, they have designated to meet their load forecast. This capacity can be acquired either through an annual capacity auction, bilateral purchase, or self-supply. For the capacity market, MISO is divided into 10 zones whose forecast demand must be met by internal generation, demand-side resources, or deliverable external capacity.

<sup>165</sup> Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), <https://www.eia.gov/electricity/data/eia860m/>.

<sup>166</sup> Potomac Economics, *2021 State of the Market Report for the MISO Electricity Markets*, at 100 (June 2022), [https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM\\_Report\\_Body\\_Final.pdf](https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf).

Resources used to meet LSEs' annual capacity requirements must offer that capacity into MISO's energy markets and, when qualified, into the ancillary services markets, for each hour of each day for the entire planning year. Must-offer requirements support MISO's mitigation process by providing an objective measure with which to identify physical withholding.

### **Special Provisions for Essential Resource Retirements**

Power plant owners that seek to retire or suspend a generator must first obtain approval from MISO. The RTO evaluates plant retirement or suspension requests against reliability needs, and System Support Resource (SSR) designations are made where reliability is threatened. Once an agreement has been reached, SSRs receive compensation associated with remaining online and available.

### **Financial Transmission Rights**

MISO holds FTR auctions to allow market participants the opportunity to acquire FTRs, sell FTRs that they currently hold, or to convert ARR to FTRs. ARRs provide LSEs, and entities who make transmission upgrades, with a share of the revenues generated in the FTR auctions. MISO allocates ARRs to transmission customers relative to historical usage, or upgraded capability, of the transmission system. MISO FTRs are monthly and annual products.

### **Virtual Transactions**

MISO's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual transactions allow for more participation in the day-ahead, price-setting process, allow participants to manage risk, and promote price convergence between the day-ahead and real-time markets.

These transactions are a component of the day-ahead market where the bids and offers are included in the determination of the LMP along with physical resource offers and actual load bids. Market participants, whose virtual transactions clear in the day-ahead market, have their positions cleared in the real-time market at the

real-time price. Virtual bids and offers are allowed in MISO at any pricing node or aggregate of pricing nodes.

### **Credit Requirements**

MISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. The RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

## **Southwest Power Pool (SPP)**

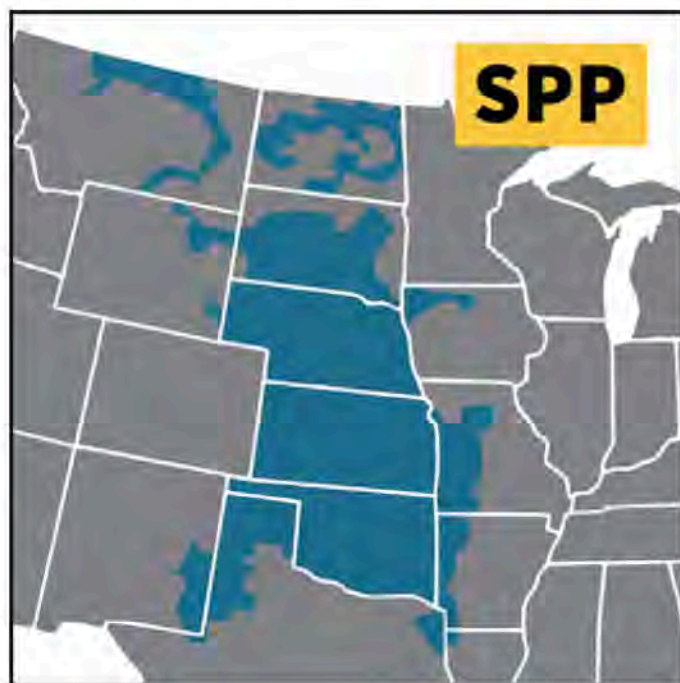
### **MARKET PROFILE**

SPP's RTO manages transmission in fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. Founded as an 11-member tight power pool in 1941, SPP achieved RTO status in 2004, ensuring reliable power supplies, adequate transmission infrastructure, and competitive wholesale electricity prices for its members. SPP operates through its control center in Little Rock, Ar.

SPP began operating its real-time Energy Imbalance Service (EIS) market in 2007. In the same year, SPP became a FERC-approved Regional Entity. The SPP Regional Entity serves as the reliability coordinator for the NERC region, overseeing compliance with reliability standards.

SPP implemented its Integrated Marketplace in March 2014 which includes a day-ahead energy market, a real-time energy market, and an operating reserve market. SPP's Integrated Marketplace also includes a market for Transmission Congestion Rights. The SPP Integrated Marketplace co-optimizes the deployment of energy and operating reserves to dispatch resources on a least-cost basis.

**Figure 2-24: Southwest Power Pool**



Source: Hitachi Energy, Velocity Suite

SPP expanded its footprint in 2015, incorporating the Western Area Power Administration – Upper Great Plains region, the Basin Electric Power Cooperative, and the Heartland Consumers Power District. The expansion nearly doubled SPP’s service territory by square miles, adding more the 5 GW of peak demand and over 7 GW of generating capacity.<sup>167</sup>

SPP also operates a real-time energy imbalance market in the Western Interconnect, which is described further below.

### **Peak Demand**

SPP’s all-time peak demand of 53 GW occurred in summer 2022.<sup>168</sup>

### **Imports and Exports**

SPP has interties with MISO, TVA, and other systems. Additionally, SPP has two DC interties with ERCOT

and seven DC interties to the Western Interconnection through New Mexico, Colorado, Nebraska, South Dakota and Montana. At times, SPP is both a net importer and net exporter of electricity at times.

### **Market Participants**

SPP’s market participants include investor-owned utilities, generation and transmission cooperatives, independent power producers, municipal utilities, state authorities, independent transmission companies, power marketers, financial participants, and a federal power marketing administration.

### **Membership and Governance**

SPP is governed by a board of directors representing and elected by its members. Supporting the board is the members committee, which provides non-binding input. The members’ committee is composed of representatives from each sector of SPP’s membership. The SPP Regional State Committee represents retail regulatory commissions from state agencies and provides input on matters of regional importance related to the development and operation of bulk electric transmission.

### **Transmission Owners**

SPP’s largest transmission owners include:

- American Electric Power
- Oklahoma Gas and Electric
- Westar Energy
- Southwestern Public Service (Xcel Energy)
- Great Plains Energy
- Kansas City Power & Light
- Omaha Public Power District
- Nebraska Public Power District
- Tri-State Generation and Transmission
- Empire District Electric
- Western Area Power Administration – Upper Great Plains
- Western Farmers Electric Cooperative

167 Southwest Power Pool, *Western, Basin, Heartland join Southwest Power Pool*, at 1 (October 2015), <https://www.spp.org/about-us/newsroom/western-basin-heartland-join-southwest-power-pool/>.

168 Southwest Power Pool, *Fast Facts*, <https://www.spp.org/about-us/fast-facts/>.

## Chronic Constraints

SPP has certain pathways that are more likely to become congested, based on the physical characteristics of the transmission grid and associated transfer capability, the geographic distribution of load, and the geographic differences in fuel costs. The eastern side of the SPP footprint has a higher concentration of load and congestion can occur when wind-powered generation from the west tries to travel across limited connections to the east. The most significant congestion has typically occurred in the Oklahoma and Texas Panhandle region.<sup>169</sup>

## Transmission Planning

SPP conducts its transmission planning according to its Integrated Transmission Planning process, which is a three-year planning process that includes 20-year, 10-year, and near-term assessments designed to identify transmission solutions that address both near-term and long-term transmission needs. The Integrated Transmission Planning process focuses on identifying cost-effective regional transmission solutions, which are identified in an annual SPP Transmission Expansion Plan report.

## Supply Resources

The total capacity in SPP is approximately 94 GW and is predominately composed of natural gas and coal-fired

generators, as shown in the bar chart below. Wind is an important and growing resource in the region.

## Demand Response

SPP allows demand response resources to register in its market.<sup>170</sup> As of December 31, 2021, 102 demand resources participated in SPP's markets, representing 176 MW of nameplate capacity. While the demand response resources can participate in SPP's markets, they are rarely dispatched.

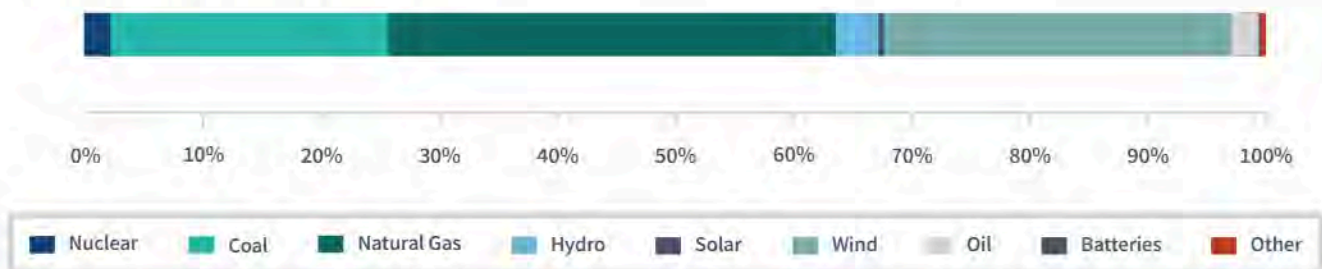
SPP allows Market Participants to register two types of demand response resources: Block Demand Response (BDR) resources and Dispatchable Demand Response (DDR) resources. BDR resources can participate in SPP's markets by providing energy and reserves in 60-minute blocks. DDR resources can participate in SPP's markets by providing energy, regulation, and reserves in 5-minute blocks.

## MARKET FEATURES

### Energy Markets

SPP operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. SPP's real-time market operates in 5-minute intervals.

Figure 2-25: SPP Capacity Resources



Source: EIA Form 860-M<sup>171</sup>

169 See Southwest Power Pool Market Monitoring Unit, *State of the Market 2022* (May 2022), at 202, <https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf>.

170 SPP Market Monitor, *State of the Market 2021* (May 10, 2021), at 49, <https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf>.

171 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), <https://www.eia.gov/electricity/data/eia860m/>.

## Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. SPP procures ancillary services via the co-optimized energy and ancillary services market. Separately, SPP has a ramping product to procure capacity that can quickly increase output to offset both anticipated and unforeseen future changes in generation or load within the hour, known as the Ramp Capability Product. SPP launched this ramp product in March 2022.

## Market Power Mitigation

SPP applies a set of behavioral and market outcomes tests to determine if the local market is competitive and if generator offers should be adjusted to approximate short-run marginal costs. SPP's mitigation test includes a local market power test, a conduct test, and a market impact test. Where mitigation measures are triggered by the tests, SPP generates a mitigated resource offer that the RTO then uses for dispatch, commitment, and settlement purposes.

## Capacity Markets

SPP does not offer a capacity market. However, it requires each Load Responsible Entity (LRE) to have sufficient energy supply (capacity) to cover its energy obligations. SPP develops and implements policies and processes necessary to ensure resource adequacy and determines the amount of capacity each LRE must have available to meet its energy obligations.<sup>172</sup>

## Special Provisions for Essential Resource Retirements

A generator owner who wishes to retire a unit must request that SPP study the retirement of the resource no less than one year from the expected retirement date. SPP will then conduct studies to examine the potential effects of the resource retirement including the need for transmission network upgrades, if any.

Otherwise, SPP prepares annual reliability studies as part of its system planning responsibilities. In the

event that the studies reveal a potential constraint on SPP's ability to deliver power to a local area on the transmission system, SPP works with regional stakeholders to find alternate transmission, operating procedure, or generation solutions for the constraint and thus maintain grid reliability. The SPP parties then determine an appropriate sharing of the costs, and, if unable to reach agreement, SPP will submit a proposed cost-sharing arrangement to FERC for approval.

## Financial Transmission Rights

SPP refers to FTRs as Transmission Congestion Rights (TCR). A TCR is an instrument that entitles the holder to receive compensation, or requires the holder to pay a charge, for costs that arise from transmission congestion over a selected path, or source-and-sink pair of locations on the grid. A TCR provides the holder with revenue, or charges, equal to the difference in congestion prices in the day-ahead market across the selected TCR transmission path. SPP TCRs include monthly and annual products, as well as a long-term instrument called Long-Term Congestion Rights.

A related product, ARRs, provide their holders with a share of the revenue generated in the TCR auctions. In general, ARRs are allocated based on firm transmission rights. As with TCRs, ARRs provide transmission owners and eligible transmission service customers an offset or hedge against transmission congestion costs in the day-ahead market.

## Virtual Transactions

SPP's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. In SPP, virtual bids are sometimes used in the day-ahead market as a placeholder or hedge for wind generation expected in the real-time market.

## Credit Requirements

SPP's tariff includes credit requirements that a market participant needs to meet in order to participate in the

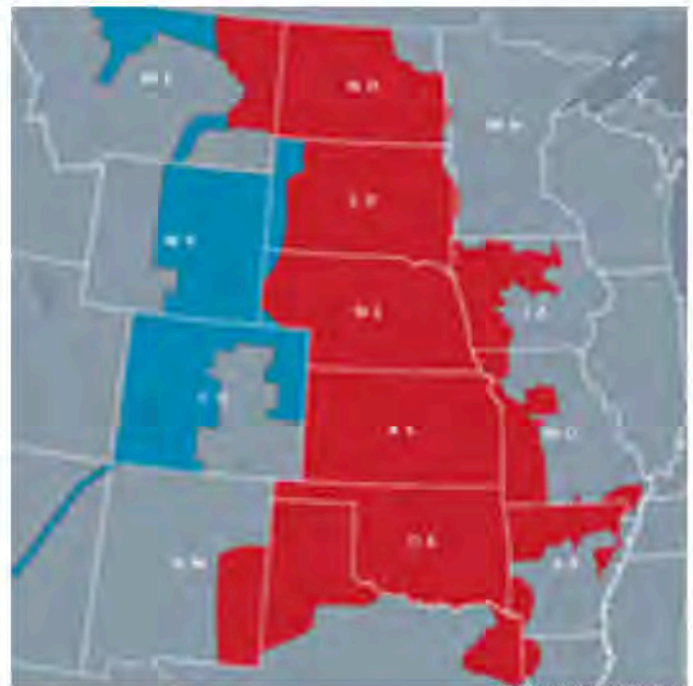
172 Southwest Power Pool Market Monitoring Unit, *State of the Market 2022 (May 2022)*, at 202, <https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf>

market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. SPP must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and various financial measures.

### Western Energy Imbalance Service (WEIS)

SPP launched its WEIS market in February 2021. The WEIS market balances generation and load regionally in real time for participants in the Western Interconnection. SPP's WEIS market centrally dispatches generation from participating resources every five minutes using the lowest-cost resource available to meet demand. As of August 2022, ten entities participate or plan to participate in the WEIS Market with three more anticipated to join in April 2023: Basic Electric Power Cooperative, BlackHills Energy (April 2023), Colorado Springs Utilities, Deseret Power Electric Cooperative, Guzman Energy, Municipal Energy Agency of Nebraska, Platte River Power Authority (April 2023), Tri-State Generation and Transmission Association, WAPA (Upper Great Plains West, Rocky Mountain, and Colorado River Storage Projects regions), and Xcel Energy (April 2023). The following map shows SPP's footprint in red and the WEIS in blue.

Figure 2-26: Western Energy Imbalance Service



Source: SPP website

## California Independent System Operator (CAISO)

### MARKET PROFILE

CAISO operates an ISO serving most of California and part of Nevada. CAISO is a California nonprofit public benefit corporation started in 1998 when the state restructured its electric power industry. CAISO manages wholesale electricity markets, centrally dispatching

electric generators. In managing the grid, CAISO provides open access to the transmission system and performs long-term transmission planning. It manages energy and ancillary markets in day-ahead and real-time markets and is responsible for regional reliability. CAISO also operates a real-time energy imbalance market, the Western Energy Imbalance Market (WEIM), which is discussed further below. CAISO operates its grid out of its main control center in Folsom, CA.

### Peak Demand

CAISO's all-time peak demand was 52 GW in summer 2022.<sup>173</sup>

### Imports and Exports

Up to about one-third of CAISO's energy is supplied by imports, principally from the Southwest (Arizona, Nevada, and New Mexico) and the Pacific Northwest (Oregon, Washington, and British Columbia). Imports from the Pacific Northwest generally increase in the

173 California ISO, *California ISO Peak Load History 1998 through 2022*, at 1 (n.d.), <http://www.caiso.com/documents/californiaisopeakloadhistory.pdf>.

late spring when hydroelectric production peaks from increases in winter snowmelt and runoff.

### Market Participants

CAISO's market participants include load-serving investor-owned utilities, load-serving municipal utilities, generators, power marketers, utility customers, and financial entities.

### Membership and Governance

The CAISO has a board of governors that consists of five members appointed by the governor and confirmed by the California Senate. The board provides corporate direction, reviews and approves management's annual strategic plans, and approves CAISO's operating and capital budgets.

CAISO uses an informal stakeholder process to propose solutions to problems that may ultimately require a filing at FERC. Unlike other RTOs, which have a formal committee structure, CAISO's stakeholder process generally consists of rounds of dialogue with stakeholders on major policy issues.

### Transmission Owners

CAISO's largest transmission owners include:

- Pacific Gas and Electric
- Southern California Edison
- San Diego Gas and Electric
- Valley Electric Association
- Municipal utilities such as Vernon, Anaheim, and Riverside

### Chronic Constraints

CAISO has several locally constrained areas, typically near population centers and where transmission lines have relatively low voltage (115 kV and below). The locally constrained areas that have local capacity requirements include the Greater Bay Area, Greater Fresno, Sierra, Humboldt, Los Angeles Basin, San Diego, and North Coast/North Bay.

### Transmission Planning

CAISO conducts an annual transmission planning

Figure 2-27: California Independent System Operator



Source: Hitachi Energy Velocity Suite

process with stakeholders that includes both short-term and long-term projects.

### Supply Resources

The total capacity in CAISO is over 70 GW and is predominately composed of natural gas-fired and hydroelectric generators, as shown in the bar chart below. CAISO also has substantial renewable resources, including roughly half of the installed solar capacity in the U.S.

### Demand Response

Demand response participation in the wholesale energy market includes programs entitled Proxy Demand Response, Reliability Demand Response Resources, and CAISO's Participating Load program. Proxy Demand Response allows for customer loads, aggregated by LSEs or third-party providers, to offer load reduction into CAISO's day-ahead, real-time, and ancillary services markets in return for compensation. Reliability Demand Response Resources allows customer loads, also aggregated by LSEs or third-party providers, to reduce load for compensation when triggered for

Figure 2-28: CAISO Capacity Mix



Source: EIA Form 860-M<sup>175</sup>

reliability-related events. Reliability Demand Response Resources can also offer into the day-ahead market. The Participating Load program allows the CAISO operators to directly curtail end-users' load, rather than through aggregators. This is a relatively small program that is primarily composed of the power demand from California's water pumping projects. Other demand response in California consists of programs for managing peak summer demands operated by the state's electric utilities. In general, activation of the utility demand response programs is based on criteria that are internal to the utility or when CAISO issues a Flex Alert. Flex Alerts also inform consumers of how and when to conserve electricity usage.

## MARKET FEATURES

### Energy Markets

CAISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. CAISO operates a 15-minute market to adjust schedules from those determined in the day-ahead market, then a 5-minute market to balance supply and load in real-time. Real-time bids can be submitted up to 75 minutes before the start of the operating hour.

CAISO also procures capacity in the real-time market to provide upward and downward ramping of generation in order to accommodate changes in net load with the Flexible Ramping Product.<sup>175</sup> This service provides compensation to the generators selected to provide the desired flexible ramping capability.<sup>176</sup>

### Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. CAISO procures ancillary services via its co-optimization of energy and ancillary services in its energy markets

In addition to ancillary services, CAISO has implemented a ramping product to procure capacity that can quickly increase output to offset changes in generation or load, known as the Flexible Ramping Product.

### Market Power Mitigation

CAISO applies a set of behavioral and market outcome tests to determine if the local market is competitive and if generator offers should be adjusted to approximate price levels that would be seen in a competitive market – close to short-run marginal costs.

174 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), <https://www.eia.gov/electricity/data/eia860m/>.

175 Net load in CAISO is total market demand minus generation output from solar and wind resources.

176 CAISO describes ramping capability as a resource's ability to move from one energy output to a higher (upward ramp) or lower (downward ramp) energy output; *California Independent System Operator Corp.*, 156 FERC ¶ 61,226, at P 2 (2016).

**Figure 2-29: Western Energy Imbalance Market**



Copyright © 2023 California ISO

## Capacity Markets

CAISO does not operate a formal capacity market, but it does have a mandatory resource adequacy (RA) requirement. The program requires LSEs to procure 115 percent of their aggregate system load on a monthly basis, unless a different reserve margin is mandated by the LSE's local regulatory authority. The program provides deliverability criteria that each LSE must meet, as well as system and local capacity requirements and flexibility requirements.

The CAISO market rules also include must-offer provisions pertaining to resources procured as RA resources. These resources must make themselves available to the CAISO day-ahead and real-time markets for the capacity for which they were counted.

## Special Provisions for Essential Resource Retirements

CAISO employs RMR contracts to assure that it has the ability to reliably serve load in local import-constrained areas. RMR contracts also help to mitigate any local market power that one or more units may have. Over time, CAISO has been able to significantly decrease its RMR designations in much of the system. Remaining generators with RMR contracts are located primarily near the San Francisco and Los Angeles areas.

## Financial Transmission Rights

In California, FTRs are referred to as Congestion Revenue Rights (CRR). A CRR is an instrument that entitles the CRR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. The CRR also requires its holder to pay a charge for those hours when congestion occurs in the opposite direction of the selected source-and-sink pair. CRRs are monthly or quarterly products. CRRs can be bought at auction or allocated by CAISO. Allocated CRRs receive the congestion value for a specific path, similar to a converted FTR. CAISO also allocates open market CRR auction revenues to LSEs, based on their physical participation in the market, similar to an ARR in other markets.

## Virtual Transactions

CAISO's market includes a virtual transactions feature, termed convergence bidding. CAISO's convergence bidding includes both virtual supply and virtual demand transactions.

## Credit Requirements

CAISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be absorbed by all market participants. CAISO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to

certain restrictions – CAISO must review the entity’s request relative to various creditworthiness-related specifications such as tangible net worth, net assets, and credit rating.

#### *Western Energy Imbalance Market (WEIM)*

On Nov. 1, 2014, CAISO began operation of an energy imbalance market (EIM) with PacifiCorp’s two BAAs, PacifiCorp East and PacifiCorp West. The EIM is an extension of the CAISO’s real-time market into other BAAs in the Western Interconnection. The market dispatches resources inside the participating entities’ BAAs to meet intra-hour changes in their energy demand and supply. The EIM’s imbalance energy helps the BAAs meet their energy demand in real-time. Overall, EIM energy represents about two to three percent of the energy used to meet load in the participating BAAs. With the balancing authorities in the Pacific Northwest, the EIM integrates low-cost hydroelectric power generation with the significant amount of solar and wind generation capacity in CAISO.

The EIM is a voluntary market where the participating balancing authorities can choose which resources to include in the market. The market participants have the flexibility to add and remove capacity from the EIM on an hourly basis. The transmission system operators for each participating BAA preserve the responsibility and flexibility to respond to events such as a sudden large imbalance between load and supply caused by a loss of a power plant or transmission line.

As of November 2022, the EIM consisted of the following LSEs and their respective BAAs: BPA, Puget Sound Energy, Portland General Electric, PacifiCorp West, PacifiCorp East, Idaho Power, NV Energy, Tucson Electric Power, Avista, NorthWestern Energy, Los Angeles Department of Water & Power, Public Service

Company of New Mexico, Turlock Irrigation District, Salt River Project, Seattle City Light, Balancing Authority of Northern California, Idaho Power Company, Portland General Electric, Puget Sound, NV Energy, Arizona Public Service, and CAISO. Additionally, Powerex (the marketing arm of the Canadian utility, BC Hydro) joined the EIM, providing contributions of generation and load imbalance (the difference between generation supply and demand schedules).<sup>177</sup> Other balancing authorities have expressed interest in becoming EIM Entities.

The EIM provides a market mechanism for dispatching generation resources to meet imbalance energy needs along with a limited amount of power flows between the participating BAAs. The market dispatches generation based on the relative cost of the resources, resulting in cost savings for the participants. Before the EIM, a balancing authority such as PacifiCorp West or PacifiCorp East resolved imbalances between energy demand and supply in real-time by dispatching its resources and using ancillary services (mainly regulation). Under the EIM, by contrast, the market automates the dispatch of enough resource capacity within the BAAs, along with transmission flows between BAAs, to resolve energy imbalances.<sup>178</sup> The automated EIM sets LMPs at both 15-minute and 5-minute intervals.

Along with dispatch cost savings, the EIM also helps integrate renewable generation resources. Prior to the EIM, CAISO imported power from outside its service territory to balance load throughout most hours of the day. However, with the growth of solar and wind generation, particularly in California, there were periods when these resources were forced to curtail because there was too much energy offered into the market. Now, with the EIM, any excess power can be exported throughout the participating BAAs. In some hours, this results in power exports from CAISO to other BAAs.<sup>179</sup>

177 Powerex (BC Hydro) also makes transmission rights available to the EIM, providing its power to the EIM at the British Columbia-U.S. border

178 The EIM software calculates dispatch solutions for the EIM market area as a whole. Consequently, participating balancing authorities need not maintain high levels of reserves.

179 See Department of Market Monitoring – California ISO, *2017 Annual Report on Market Issues & Performance*, at 118 (June 2018), <http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf>.

As the independent system operator of the EIM, CAISO addresses local market power mitigation at 5-minute and 15-minute intervals across the EIM area, which includes the non-CAISO balancing authority areas. CAISO also procures a Flexible Ramp Product to

provide upward and downward flexible capacity to meet energy ramp requirements. In these respects, CAISO's operator responsibilities have grown in the EIM as enhancements to the market design have been implemented.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) )  
Emergency Order: Midcontinent )  
Independent System Operator )  
(MISO) )  
\_\_\_\_\_ )

Order No. 202-26-16

Exhibit to  
Motion to Intervene and Request for Rehearing and Stay of  
Public Interest Organizations

Exhibit 47  
2024 Coal Ash Inspection  
Report



REPORT

**J.H. Campbell Generating Facility**  
**2024 Facility Inspection Report**  
*West Olive, Michigan*

*Pursuant to 40 CFR 257.84*

Submitted to:

**Consumers Energy Company**

1945 W. Parnall Road  
Jackson, Michigan 49201

Submitted by:

**WSP Michigan Inc.**

400 136<sup>th</sup> Avenue, Building 100, Suite B2  
Holland, Michigan 49424

US-WSP-31404348MI.7870

October 2024

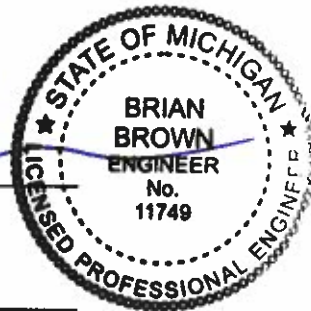


# Certification

## Professional Engineer Certification Statement [40 CFR 257.84]

I hereby certify that, having reviewed the attached documentation and being familiar with the provisions of Title 40 of the Code of Federal Regulations Section 257.84 (40 CFR Part 257.84), I attest that this Annual Inspection Report is accurate and has been prepared in accordance with good engineering practices, including the consideration of applicable industry standards, and with the requirements of 40 CFR Part 257.84.

WSP Michigan Inc.



Signature

October 6, 2024

Date of Report Certification

Brian A. Brown, PE

Name

6201311749

Professional Engineer Certification Number

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## **APPENDICES**

Appendix A – Visual Inspection Checklist

## 1.0 INTRODUCTION

On April 17, 2015, the United States Environmental Protection Agency (EPA) issued the Coal Combustion Residual (CCR) Resource Conservation and Recovery Act (RCRA) Rule (40 CFR 257 Subpart D) (“CCR RCRA Rule”). The CCR RCRA Rule requires owners or operators of existing CCR landfills to have those units inspected on an annual basis by a qualified professional engineer (QPE) in accordance with 40 CFR 257.84(b). The annual QPE inspections are required to be completed and the results documented in inspection reports per CFR 257.84(b)(2) for landfills.

WSP Michigan Inc. (WSP) was retained by Consumers Energy Company (CEC) to perform the QPE annual inspection of the Dry Ash Landfill at the J.H. Campbell Generating Facility (JH Campbell) to document, to the extent reasonable based on information provided by CEC and the limits of the visual inspection; that the design, construction, operation, and maintenance for the CCR unit is consistent with recognized and generally accepted good engineering standards. WSP reviewed available information regarding the status and condition of the CCR unit and performed an onsite visual inspection to identify signs of distress or malfunction of the CCR unit and visible leachate collection system features.

## 2.0 BACKGROUND AND DOCUMENT REVIEW SUMMARY

The Dry Ash Landfill serves as the facility’s primary disposal area for dry ash and currently consists of six dual lined landfill cells and two leachate storage ponds. Total permitted capacity of the landfill, per the most current Construction Permit Application (CPA) Number 4173 dated November 30, 2021, is 10,032,000 cubic yards (CY) with approximately 6,177,295 CY consumed at the time of the inspection, per Consumers reporting. It should be noted that the total permitted volume capacity will be achieved once the remaining permitted cells have been constructed and filled.

At the time of the 2024 inspection; Cells 1, 2, 3, 4, 5, and 6 had been constructed with active filling occurring in uncapped portions of Cell 4, Cell 5, and Cell 6. Phase 6 of closure construction was completed in 2019 on portions of Cells 3 and 4. A final cover system was in place on Cell 3, the eastern portion of Cell 4, the north and east slopes of Cell 2, and the north and west slope of Cell 1.

The applicable available information reviewed for this assessment is summarized in Table 1 below.

**Table 1: Summary of Background Document Review**

Document	Date	Author
Weekly inspections performed by CEC	July 2023 – July 2024	Dry Ash Landfill Qualified Personnel
J.H. Campbell Dry Ash Landfill 2023 Annual RCRA CCR Landfill Inspection Report	October 2023	WSP Michigan Inc.
J.H. Campbell Dry Ash Landfill 2022 Annual RCRA CCR Landfill Inspection Report	October 2022	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill Solid Waste Disposal Area Construction Permit	November 2021	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill 2021 Annual RCRA CCR Landfill Inspection Report	October 2021	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill 2020 Annual RCRA CCR Landfill Inspection Report	October 2020	Golder Associates Inc.

Document	Date	Author
J.H. Campbell Dry Ash Landfill 2019 Annual RCRA CCR Landfill Inspection Report	October 2019	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill 2018 Annual RCRA CCR Landfill Inspection Report	October 2018	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill Construction Permit Upgrade Request Cells 5 through 9	March 2018	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill 2017 Annual RCRA CCR Landfill Inspection Report	October 2017	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill 2016 Annual RCRA CCR Landfill Inspection Report	October 2016	Golder Associates Inc.
J.H. Campbell Dry Ash Landfill 2015 Initial Annual RCRA CCR Landfill Inspection Report	January 2016	Golder Associates Inc.
Surveillance Monitoring Programs (SMPs)	December 2010, Revised 2015	CEC
J.H. Campbell Ash Storage Facility Expansion	November, 1993	STS Consultants Ltd.

### 3.0 2024 VISUAL INSPECTION

WSP performed an onsite inspection of the Dry Ash Landfill on August 6, 2024 and August 7, 2024. WSP inspectors Brian Brown, PE and Scott Fulmer, were accompanied by two CEC representatives, as follows:

- Mr. George McKenzie, PE - CEC System Engineering Department
- Mr. Joseph Firlit, PMP - CEC Manager Engineering Support

The inspection checklist form is provided in Appendix A. The checklist includes observations and recommendations resulting from the visual inspection and also includes the following information as stipulated in 40 CFR 257.84(b):

- Any changes in geometry of the structure since the previous annual inspection.
  - At the time of inspection, the southern portion of the landfill (Cell 4, Cell 5, and Cell 6) was undergoing active filling.
- Approximate volume of CCR at the time of inspection.
  - The volume of airspace consumed within the Dry Ash Landfill at the time of inspection was estimated at approximately 6,177,295 CY.
- Appearances of an actual or potential structural weakness of the CCR unit, in addition to any existing conditions that are disrupting or have the potential to disrupt the operation and safety of the CCR unit and appurtenant structures.
  - None were observed or noted.

- Any other change(s) which may have affected the stability or operation of the CCR unit since the previous inspection.
  - None were observed or noted.

The checklist categorizes observed conditions of the impoundment or appurtenant structures as either acceptable, monitor/maintain, investigate, or repair, which are defined as follows:

- **Acceptable:** The condition was visually documented to be acceptable, requiring no action beyond periodic inspection in accordance with the SMP and typical maintenance.
- **Monitor/Maintain:** The condition was visually identified to exhibit the potential for or show existing degeneration that should either be monitored or maintained as detailed in the checklist.
  - Items identified in this category are not considered a deficiency or release as classified under 40 CFR 257.84(b)(5) requiring immediate action by CEC.
- **Investigate:** The limitations of the visual inspection did not allow for an opinion to be made on the condition of the item observed, and WSP recommends additional investigation to categorize the item.
- **Repair:** WSP recommends that items identified with a repair designation exhibited conditions that should initiate measures be taken to rectify the area of concern.
  - It should be noted that no items identified for repair were considered a deficiency or release as classified under 40 CFR 257.84(b)(5) requiring immediate action by CEC.

Based on a review of previous inspection reports listed in Table 1 compared to conditions noted during the inspection, the following changes were observed:

- Localized areas of sparse vegetation, and some undesirable woody vegetation observed in localized areas of the Dry Ash Landfill final cover;
- Small animal burrows, animal cover damage, and minor erosion noted along north, east, and south sides of the Dry Ash landfill along storm water berms and toe;
- Minor erosion in localized areas on the Dry Ash Landfill and active measures to address historical erosion were observed; and
- Area of leachate collection sand erosion causing exposure of geocomposite observed on the Dry Ash Landfill Cell 5/6 intercell berm.

## 4.0 LIMITATIONS OF ASSESSMENT

WSP has conducted the site inspection and prepared this report for the Dry Ash Landfill at J.H. Campbell. The factual data, assessment, interpretations, and recommendations provided herein are based on the results of field observations from site inspections performed by WSP and review of previous site inspection reports provided to WSP by CEC and pertain to the specific project as described in this report and are not applicable to any other project or site location.

WSP has prepared this report in a manner consistent with that level of care and skill ordinarily exercised by members of the engineering and science professions currently practicing under similar conditions and has

characterized the site conditions within the limitations of the scope of services as defined by CEC and subject to the time limits and physical constraints applicable to this report. No other warranty, expressed or implied, is made. Any change of site conditions, purpose, development plans, or operation may alter the validity of this report. WSP cannot be responsible for use of this report, or portions thereof, unless WSP is requested to review and, if necessary, revise the report.

## 5.0 CLOSING

This report has been prepared in general accordance with normally accepted civil engineering practices to fulfill the Resource Conservation and Recovery Act (RCRA) reporting requirements in accordance with 40 CFR 257.84(b)(2). WSP has reviewed the available information on the J.H. Campbell Dry Ash Landfill and performed an onsite visual inspection. WSP's assessment is limited to the information provided by CEC and to the aspects that could be inspected visually in a safe manner. WSP cannot attest to the condition of subsurface or submerged structures.

### WSP Michigan Inc.



Brian Brown, PE  
*Consultant, Geotechnical Engineer*



Blaine Litteral, PE  
*Vice President*

**APPENDIX A**

# Visual Inspection Checklist

## CCR LANDFILL VISUAL INSPECTION CHECKLIST

**Facility Name:** J.H. Campbell Dry Ash Landfill

**Owner:** Consumers Energy Company (CEC)

**Purpose of Facility:** Dry Ash Disposal

**County, State:** Ottawa County, Michigan

**Inspected By:** Brian Brown and Scott Fulmer

**Inspection Date:** August 6<sup>th</sup> & 7<sup>th</sup>, 2023

**Weather:** 72-degrees F, Cloudy.

ITEM					REMARKS
	Acceptable	Monitor/Maintain	Investigate	Repair	
1. General Conditions					
a. Current volume of CCR					Total Airspace Consumed: 6,177,295 CY Volume of leachate drainage layer: 140,355 CY Volume of CCR: 6,036,940 CY
b. Alterations	X				
c. Grass cover	X				
d. Settlement / misalignment / cracks	X				None observed.
e. Leachate Collection	X				.
2. Landfill Slope					
a. Erosion – liner exposed?		X			Exposed geocomposite on Cell 5/6 intercell berm, see note 3.
b. Rodent burrows		X			Burrows observed on final cover benches, adjacent to leachate vaults, and near toe of slope, see note 3.
c. Vegetation	X				Some localized areas of sparse vegetation, see note 3.
d. Cracks/settlement	X				None observed.
e. Riprap/other erosion protection	X				
f. Slide, Slough, Scarp	X				None observed.

ITEM	Acceptable	Monitor/Maintain	Investigate	Repair	REMARKS
g. Benches	X				
h. Final Cover		X			Localized areas of minor erosion on final cover slopes, see note 3.
i. Downchutes	X				
3. Crest					
a. Soil condition	X				
b. Comparable to design width or previous inspection	X				
c. Vegetation	X				
d. Rodent burrows	X				
e. Exposed to heavy traffic	X				
f. Damage from vehicles / machinery	X				None observed.
4. Toe					
a. Vegetation	X				
b. Rodent burrows		X			Small animal burrows observed near toe of slope, see note 3.
c. Settlement	X				None observed.
d. Drainage conditions	X				
e. Seepage	X				None observed.

**Notes:**

- 1) Leachate collection system inspection was limited by visual observation of surficial components of the system, i.e. condition of riser pipes.
- 2) Maintain erosion controls per the SMP. This is not a deficiency or release as classified under 40 CFR 257.84(b)(5).
- 3) Features observed and documented in this checklist were not considered a deficiency or release as classified under 40 CFR 257.84(b)(5) and required no immediate action beyond periodic inspection in accordance with the SMP and typical maintenance.

**wsp**

**wsp.com**

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) )  
Emergency Order: Midcontinent )  
Independent System Operator )  
(MISO) )  
\_\_\_\_\_ )

Order No. 202-26-16

Exhibit to  
Motion to Intervene and Request for Rehearing and Stay of  
Public Interest Organizations

# Exhibit 48

## 2021 CWA Permit

**PERMIT NO. MI0001422**



**STATE OF MICHIGAN**  
**DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY**

**AUTHORIZATION TO DISCHARGE UNDER THE  
NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM**

In compliance with the provisions of the Federal Water Pollution Control Act, 33 U.S.C., Section 1251 *et seq.*, as amended; Part 31, Water Resources Protection, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (NREPA); Part 41, Sewerage Systems, of the NREPA; and Michigan Executive Order 2019-06,

**Consumers Energy Company**  
One Energy Plaza  
Jackson, MI 49201

is authorized to discharge from the **Consumers Energy Company, J. H. Campbell Power Plant** located at

17000 Croswell St.  
West Olive, MI 49460

designated as **CECO-J H Campbell Power Plt**

to the receiving waters named Lake Michigan and the Pigeon River in accordance with effluent limitations, monitoring requirements, and other conditions set forth in this permit.

This permit is based on a complete application submitted on March 22, 2016, as amended through September 1, 2016; and a complete modification request submitted on January 11, 2021.

**This permit originally took effect on June 1, 2018. This modified permit takes effect on October 1, 2021.** The provisions of this permit are severable. After notice and opportunity for a hearing, this permit may be modified, suspended, or revoked in whole or in part during its term in accordance with applicable laws and rules. On its original effective date, the permit superseded National Pollutant Discharge Elimination System (NPDES) Permit No. MI0001422 (expiring October 1, 2016).

This permit and the authorization to discharge shall expire at midnight on **October 1, 2022**. In order to receive authorization to discharge beyond the date of expiration, the permittee shall submit an application that contains such information, forms, and fees as are required by the Michigan Department of Environment, Great Lakes, and Energy (Department) by **April 4, 2022**.

**Issued:** May 29, 2018. Modified (major) September 30, 2021.

Original signed by Christine Alexander  
Christine Alexander, Manager  
Permits Section  
Water Resources Division

## PERMIT FEE REQUIREMENTS

In accordance with Section 324.3120 of the NREPA, the permittee shall make payment of an annual permit fee to the Department for each October 1 the permit is in effect regardless of occurrence of discharge. The permittee shall submit the fee in response to the Department's annual notice. Payment may be made electronically via the Department's MiWaters system. The MiWaters website is located at <https://miwaters.deq.state.mi.us>. Payment shall be submitted or postmarked by January 15 for notices mailed by December 1. Payment shall be submitted or postmarked no later than 45 days after receiving the notice for notices mailed after December 1.

**Annual Permit Fee Classification:** Industrial-Commercial Major

In accordance with Section 324.3118 of the NREPA, the permittee shall make payment of an annual storm water fee to the Department for each January 1 the permit is in effect regardless of occurrence of discharge. The permittee shall submit the fee in response to the Department's annual notice. Payment may be made electronically via the Department's MiWaters system. The MiWaters website is located at <https://miwaters.deq.state.mi.us>. Payment shall be submitted or postmarked by March 15 for notices mailed by February 1. Payment shall be submitted or postmarked no later than 45 days after receiving the notice for notices mailed after February 1.

## CONTACT INFORMATION

Unless specified otherwise, all contact with the Department required by this permit shall be made to the Grand Rapids District Office of the Water Resources Division. The Grand Rapids District Office is located at State Office Building, Fifth Floor, 350 Ottawa Ave NW, Unit 10, Grand Rapids, Michigan, 49503-2341, Telephone: 616-356-0500, Fax: 616-356-0202.

## CONTESTED CASE INFORMATION

Any person who is aggrieved by this permit may file a sworn petition with the Michigan Administrative Hearing System within the Michigan Department of Licensing and Regulatory Affairs, c/o the Michigan Department of Environment, Great Lakes, and Energy, setting forth the conditions of the permit which are being challenged and specifying the grounds for the challenge. The Department of Licensing and Regulatory Affairs may reject any petition filed more than 60 days after issuance as being untimely.

**PART I**

**Section A. Limitations and Monitoring Requirements**

**1. Effluent Limitations, Monitoring Point 001A**

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 984.841 MGD of noncontact cooling water; intake screen backwash; low volume wastewater, which includes but is not limited to: boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, and water from floor drains; bottom ash transport water; chemical metal cleaning wastewater; coal pile runoff; storm water; leachate retention pond water; reverse osmosis backwash and reject water; and groundwater seepage from ash ponds and the recirculation pond from Monitoring Point 001A through Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

<u>Parameter</u>	<u>Maximum Limits for Quantity or Loading</u>			<u>Maximum Limits for Quality or Concentration</u>			<u>Monitoring Frequency</u>	<u>Sample Type</u>
	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>		
Flow	(report)	(report)	MGD	---	---	---	Daily	Report Total Daily Flow
Total Residual Oxidant (TRO) – See Part I.A.1.g.								
<u>During Chlorination – No Bromine Use</u>								
Total Residual Chlorine (TRC) Discharge Time	---	---	---	---	(report)	min/day	Daily	Report Total Discharge Time
Continuous (greater than 160 min/day)	---	---	---	---	38	ug/l	Daily	Grab
Intermittent (less than/equal to 160 min/day)	---	---	---	<u>Daily Average</u> 200	<u>Instantaneous Maximum</u> 300	ug/l	Daily	Grab
<u>During Bromination – Alone or With Chlorine</u>								
Intermittent (less than/equal to 120 min/day)	---	---	---	(report)	50	ug/l	Daily	Grab
TRO Discharge Time	---	---	---	---	<u>Maximum Daily</u> 120	min/day	Daily	Report Total Discharge Time
Total Phosphorus (as P)	---	(report)	lbs/day	---	(report)	mg/l	Quarterly	Grab
Total Copper, see Part I.A.1.i.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Iron, see Part I.A.1.i.	---	---	---	---	(report)	mg/l	Daily	Grab
EVAC (as amine)	---	---	---	---	78	ug/l	Every 2 Hrs During Discharge	Grab
Temperature								
Intake (Unit 3 intake)	---	---	---	(report)	(report)	°F	Daily	Continuous
Discharge	---	---	---	(report)	(report)	°F	Daily	Continuous
Outfall Observation	(report)	---	---	---	---	---	5X Weekly	Visual

**PART I**

**Section A. Limitations and Monitoring Requirements**

<u>Parameter</u>	<u>Maximum Limits for Quantity or Loading</u>			<u>Maximum Limits for Quality or Concentration</u>			<u>Monitoring Frequency</u>	<u>Sample Type</u>
	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>		
pH	---	---	---	<u>Minimum Daily</u> 6.5	9.0	S.U.	2X Monthly	Grab

- a. **Narrative Standard**  
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.
- b. **Monitoring Location**  
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to Lake Michigan. Intake temperature monitoring shall be taken at the Unit 3 intake.
- c. **Outfall Observation**  
Outfall observation shall be reported as "yes" or "no." The permittee shall report yes if this requirement was completed and no if this requirement was not completed. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended solids, or deposits) shall be reported within 24 hours to the Department followed with a written report within 5 days detailing the findings of the investigation and the steps taken to correct the condition.
- d. **Quarterly Monitoring**  
Quarterly samples shall be taken during the months of January, April, July, and October. If the facility does not discharge during these months, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "\*G" on the Discharge Monitoring Report (DMR).
- e. **Water Treatment Additives**  
This permit does not authorize the discharge of water treatment additives without approval. Approval of water treatment additives is authorized under separate correspondence. Water treatment additives include any material that is added to water used at the facility or to a wastewater generated by the facility to condition or treat the water. In the event a permittee proposes to discharge water treatment additives, including an increased discharge concentration of a previously approved water treatment additive, the permittee shall submit a request for approval in accordance with Part I.A.6. of this permit.
- f. **Analytical Methods and Quantification Levels for Total Phosphorus and Total Copper**  
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Phosphorus and Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Phosphorus and Total Copper, shall be 10 ug/l and 1.0 ug/l, respectively, unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

## PART I

### Section A. Limitations and Monitoring Requirements

- g. Total Residual Oxidant (Chlorine and Bromine) Requirements  
Total Residual Oxidant (TRO) shall be analyzed in accordance with Part II.B.2. of this permit. TRO monitoring is only required during periods of chlorine or bromine use and subsequent discharge. The limitations specified in Part I.A.1. for the intermittent discharge of chlorine alone apply only when the discharge of chlorine alone is less than or equal to 160 minutes per day, otherwise the limitations for continuous discharge of chlorine alone apply. Authorization to discharge bromine alone or with chlorine is limited to 120 minutes per day at the limitations specified in Part I.A.1., with the additional requirement that any discharge of chlorine is further restricted to a concurrent discharge with bromine (no additional discharge of chlorine is authorized for that day).

During the intermittent discharge of chlorine without bromine ("During Chlorination – No Bromine Use"), the daily average concentration reported for TRC shall be the average of the individual analytical results of a minimum of three (3) grab samples collected at equal intervals during a chlorine discharge event, with the additional limitation that no single sample may exceed 300 ug/l.

During the intermittent discharge of bromine alone or with chlorine ("During Bromination – Alone or With Chlorine"), the daily average concentration reported for TRO shall be the average of the individual analytical results of a minimum of three (3) grab samples collected at equal intervals during a bromine, or bromine plus chlorine, discharge event, with the limitation that no single sample may exceed 50 ug/l of TRO.

The permittee shall enter "\*"G" on the Discharge Monitoring Report for the TRO discharge modes not being used.

The permittee may use dehalogenation techniques to achieve the applicable TRO limitations, using sodium thiosulfate, sodium sulfite, sodium bisulfite, or other dehalogenating reagents approved by the Department. The quantity of the reagent(s) used shall be limited to 0.6 times the stoichiometric amount of TRO for sodium thiosulfate, 1.5 times the stoichiometric amount of TRO for sodium bisulfite, and 1.8 times the stoichiometric amount of TRO for sodium sulfite. The TRO samples taken to determine the amount of each chemical to add shall be taken upstream of dehalogenation.

- h. Zebra Mussel Control Requirements  
The discharge of EVAC (as amine) is restricted to no more than six (6) times per year, for no more than 12 hours per discharge event. The permittee shall notify the Department at least one (1) week prior to each discharge.

The sampling procedure, preservation and handling, and analytical protocol for compliance monitoring for EVAC (as amine) shall be in accordance with the Acid Orange Method. The quantification level shall not exceed 50 ug/l for EVAC (as amine), unless higher levels are appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Other methods may be used upon approval from the Department. The highest value measured during the discharge event shall be reported. If the concentration in all samples is less than the quantification level, report "<" the quantification level used by the analyzing laboratory on the DMR.

- i. Total Copper and Total Iron Monitoring  
The monitoring requirements for total copper and total iron apply only when a discharge from the chemical treatment facility occurs through Monitoring Point 001A.
- j. Temperature Monitoring  
When the continuous temperature monitoring system is inoperative, the effluent daily maximum temperature may be reported on a single daily reading.

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**Section A. Limitations and Monitoring Requirements**

- k. **Acid Cleaning**  
The periodic use of Muriatic acid for cleaning sodium hypochlorite injection systems nozzles is approved.
- l. **Power Plants – Polychlorinated Biphenyls (PCB) Prohibition**  
The permittee shall not discharge any PCBs to the receiving waters of the state of Michigan as a result of plant operations.

**2. Effluent Limitations, Monitoring Point 001B (Ash Pond System Discharge)**

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 7.77 MGD of bottom ash transport water; chemical metal cleaning wastewater; coal pile runoff; low volume wastewater, which includes but is not limited to: boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, reverse osmosis backwash and reject, and water from floor drains; storm water; leachate retention pond water; and groundwater seepage from ash ponds and recirculation pond from Monitoring Point 001B through Monitoring Point 001A and Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

<u>Parameter</u>	<u>Maximum Limits for Quantity or Loading</u>			<u>Maximum Limits for Quality or Concentration</u>			<u>Monitoring Frequency</u>	<u>Sample Type</u>
	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>		
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	30	50	mg/l	Monthly	Grab
Oil & Grease	---	---	---	15	20	mg/l	Annually	Grab
Total Copper, see Part I.A.2.a.	---	---	---	---	1.0	mg/l	Daily	Grab
Total Iron, see Part I.A.2.a.	---	---	---	---	1.0	mg/l	Daily	Grab

- a. **Total Copper and Total Iron Limits**  
The limits and monitoring requirements for total copper and total iron apply only to the discharge from the chemical treatment facility when operating. The chemical treatment facility effluent shall not be mixed with any other waste stream prior to sampling for compliance monitoring. All samples shall be taken prior to discharge to the recirculation pond.
- b. **Monitoring Location**  
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to the Unit 2 condenser discharge channel.
- c. **Annual Monitoring**  
Annual samples shall be taken during the month of April. If the facility does not discharge during this month, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "\*"G" on the Discharge Monitoring Report (DMR).

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**Section A. Limitations and Monitoring Requirements**

- d. **Analytical Methods and Quantification Levels for Total Copper**  
 The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Copper shall be 1.0 ug/l unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

**3. Effluent Limitations, Monitoring Point 001C (Plant Oil/Water Separator Discharge)**

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 9.65 MGD of noncontact cooling water; low volume wastewater, which includes but is not limited to: boiler blowdown, recirculating house service water, laboratory and sampling streams, and water from floor drains; treated coal pile runoff; and storm water from Monitoring Point 001C through Monitoring Point 001A and Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

<u>Parameter</u>	<u>Maximum Limits for Quantity or Loading</u>			<u>Maximum Limits for Quality or Concentration</u>			<u>Monitoring Frequency</u>	<u>Sample Type</u>
	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>		
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	25	40	mg/l	Monthly	Grab
Oil & Grease	---	---	---	---	10	mg/l	Monthly	Grab

- a. **Monitoring Location**  
 Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to Units 1 & 2 intake channel.
- b. **Monitoring Frequency Reduction for Oil & Grease**  
 After the submittal of 12 months of data, the permittee may request, in writing, Department approval for a reduction in monitoring frequency for Oil & Grease. This request shall contain an explanation as to why the reduced monitoring is appropriate. Upon receipt of written approval and consistent with such approval, the permittee may reduce the monitoring frequency indicated in Part I.A.3. of this permit. The monitoring frequency for Oil & Grease shall not be reduced to less than Annually. The Department may revoke the approval for reduced monitoring at any time upon notification to the permittee.

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**Section A. Limitations and Monitoring Requirements**

**4. Effluent Limitations, Monitoring Point 002A (Ash Pond Discharge)**

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 10.45 MGD of bottom ash transport water; economizer ash wastewater; chemical metal cleaning wastewater; coal pile runoff; low volume wastewater which includes but is not limited to: ion exchange wastewater, boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, reverse osmosis backwash and reject water, and water from floor drains; storm water; and groundwater seepage from ash ponds and the recirculation pond from Monitoring Point 002A through Outfall 002. Outfall 002 discharges to the Pigeon River at Latitude 42.90292, Longitude -86.196033. Such discharge shall be limited and monitored by the permittee as specified below.

<u>Parameter</u>	<u>Maximum Limits for Quantity or Loading</u>			<u>Maximum Limits for Quality or Concentration</u>			<u>Monitoring Frequency</u>	<u>Sample Type</u>
	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>		
Flow	(report)	(report)	MGD	---	---	---	2X Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	30	50	mg/l	Monthly	Grab
Oil & Grease	---	---	---	15	20	mg/l	Annually	Grab
Total Copper, see Part I.A.4.f.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Iron, see Part I.A.4.f.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Arsenic	---	(report)	lbs/day	---	(report)	ug/l	Quarterly	Grab
Total Phosphorus (as P)	---	(report)	lbs/day	---	(report)	mg/l	Quarterly	Grab
Total Selenium	0.47	(report)	lbs/day	5.3	(report)	ug/l	Quarterly	Grab
EVAC (as amine), see Part I.A.4.h.		---	---	---	78	ug/l	See Permit Requirements	Grab
Outfall Observation	(report)	---	---	---	---	---	5X Weekly	Visual
				<b>Minimum Daily</b>				
pH	---	---	---	6.5	9.0	S.U.	2X Monthly	Grab

- a. Narrative Standard  
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.
- b. Monitoring Location  
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to the Pigeon River.
- c. Outfall Observation  
Outfall observation shall be reported as "yes" or "no." The permittee shall report yes if this requirement was completed and no if this requirement was not completed. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended

**PART I****Section A. Limitations and Monitoring Requirements**

solids, or deposits) shall be reported within 24 hours to the Department followed with a written report within 5 days detailing the findings of the investigation and the steps taken to correct the condition.

d. Quarterly and Annual Monitoring

Quarterly samples shall be taken during the months of January, April, July, and October. Annual samples shall be taken during the month of April. If the facility does not discharge during these months, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "\*"G" on the Discharge Monitoring Report (DMR).

e. Water Treatment Additives

This permit does not authorize the discharge of water treatment additives without approval. Approval of water treatment additives is authorized under separate correspondence. Water treatment additives include any material that is added to water used at the facility or to a wastewater generated by the facility to condition or treat the water. In the event a permittee proposes to discharge water treatment additives, including an increased discharge concentration of a previously approved water treatment additive, the permittee shall submit a request for approval in accordance with Part I.A.6. of this permit.

f. Total Copper and Total Iron Monitoring

The monitoring requirements for total copper and total iron apply only when a discharge from the chemical treatment facility occurs through Monitoring Point 002A.

g. Analytical Methods and Quantification Levels for Total Arsenic, Total Copper, and Total Phosphorus

The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Arsenic, Total Copper, and Total Phosphorus shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Arsenic, Total Copper, and Total Phosphorus shall be 1.0 ug/l, 1.0 ug/l, and 10 ug/l, respectively, unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

h. Zebra Mussel Control Requirements

The discharge of EVAC (as amine) is restricted to no more than six (6) times per year, for no more than five (5) days per discharge event. The permittee shall notify the Department at least one (1) week prior to each discharge. Upon initiation of each EVAC treatment, samples shall be collected at Monitoring Point 002A at least once every three hours for a twelve (12) hour period. Once treatment is complete following the twelve (12) hour period, sampling will occur once daily the following day for five consecutive days to show that the concentration (as an amine) measured at Monitoring Point 002A is below detection (zero).

The sampling procedure, preservation and handling, and analytical protocol for compliance monitoring for EVAC (as amine) shall be in accordance with the Acid Orange Method. The quantification level shall not exceed 50 ug/l for EVAC (as amine), unless higher levels are appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Other methods may be used upon approval from the Department. The highest value measured during the discharge event shall be reported. If the concentration in all samples is less than the quantification level, report "<" the quantification level used by the analyzing laboratory on the DMR.

i. Power Plants – Polychlorinated Biphenyls (PCB) Prohibition

The permittee shall not discharge any PCBs to the receiving waters of the state of Michigan as a result of plant operations.

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**Section A. Limitations and Monitoring Requirements**

**5. Effluent Limitations, Monitoring Point 002C**

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 1.092 MGD of chemical metal cleaning wastewater from Monitoring Point 002C through Monitoring Point 002A and Outfall 002. Outfall 002 discharges to the Pigeon River at Latitude 42.90292, Longitude -86.196033. Such discharge shall be limited and monitored by the permittee as specified below.

<u>Parameter</u>	<u>Maximum Limits for Quantity or Loading</u>			<u>Maximum Limits for Quality or Concentration</u>			<u>Monitoring Frequency</u>	<u>Sample Type</u>
	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>	<u>Monthly</u>	<u>Daily</u>	<u>Units</u>		
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Copper, see Part I.A.5.a.	---	---	---	---	1.0	mg/l	Daily	Grab
Total Iron, see Part I.A.5.a.	---	---	---	---	1.0	mg/l	Daily	Grab

- a. **Total Copper and Total Iron Limits**  
 The limits and monitoring requirements for total copper and total iron apply only to the discharge from the chemical treatment facility when operating. The chemical treatment facility effluent shall not be mixed with any other waste stream prior to sampling for compliance monitoring. All samples shall be taken prior to discharge to the recirculation pond.
- b. **Monitoring Location**  
 Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to the Unit 2 condenser discharge channel.
- c. **Analytical Methods and Quantification Levels for Total Copper**  
 The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Copper shall be 1.0 ug/l unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

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### Section A. Limitations and Monitoring Requirements

#### 6. Request for Discharge of Water Treatment Additives

Prior to discharge of any water treatment additive, the permittee shall obtain written approval from the Department. Requests for such approval shall be submitted via the Department's MiWaters system. The MiWaters website is located at <https://miwaters.deq.state.mi.us>. Instructions for submitting such a request may be obtained at <http://www.michigan.gov/deqnpdes> (near the bottom of that page, click on one or both of the links located under the Water Treatment Additives banner). Additional monitoring and reporting may be required as a condition for the approval to discharge the additive.

A request to discharge water treatment additives shall include all of the following usage and discharge information for each water treatment additive proposed to be discharged:

- a. Safety Data Sheet (formerly known as Material Safety Data Sheet);
- b. the proposed water treatment additive discharge concentration with supporting calculations;
- c. the discharge frequency (i.e., number of hours per day and number of days per year);
- d. the outfall and monitoring point from which the product is to be discharged;
- e. the type of removal treatment, if any, that the water treatment additive receives prior to discharge;
- f. the product's function (i.e. microbiocide, flocculant, etc.);
- g. a 48-hour LC<sub>50</sub> or EC<sub>50</sub> for a North American freshwater planktonic crustacean (either *Ceriodaphnia sp.*, *Daphnia sp.*, or *Simocephalus sp.*); and
- h. the results of a toxicity test for one (1) other North American freshwater aquatic species (other than a planktonic crustacean) that meets a minimum requirement of R 323.1057(2) of the Water Quality Standards. Examples of tests that would meet this requirement include a 96-hour LC<sub>50</sub> for rainbow trout, bluegill, or fathead minnow.

#### 7. Cold Shock Prevention

Cessation of thermal inputs to the receiving water by this facility shall occur gradually so as to avoid fish mortality due to cold shock during the winter months (November through March). The basis for this requirement is to allow fish associated with the discharge-heated mixing zone for Outfall 001 to acclimate to the decreasing temperature. The Department acknowledges that the permittee meets this condition based on the equipment and practices implemented at Outfall 001 identified in the application.

#### 8. Intake Screen Backwash, Outfall 001

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge intake screen backwash from Outfall 001 to Lake Michigan. The permittee shall collect and remove debris accumulated on intake trash bars and dispose of such material on land in an appropriate manner.

#### 9. Periodic/Temporary Rerouting of Combined Plant Discharge

The permittee is authorized to divert the combined flow from Units 1 & 2 and Unit 3 offshore intake structure under the following conditions: (a) for deicing when the intake water temperature falls below 36° F and intakes are at risk of becoming partially or completely restricted because of icing, (b) when Unit 3 is off line during a scheduled or unscheduled outage and the deepwater discharge pumps are turned off, or (c) for thermal treatment or control of zebra mussels and asiatic clams. The permittee is not required to provide any additional monitoring of this discharge because the effluent limitations and monitoring requirements for Outfall 001, for

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### Section A. Limitations and Monitoring Requirements

which monitoring/reporting shall be continued as usual during the diversion, will determine compliance with the applicable water quality standards and any other requirements.

#### 10. Cooling Water Intake Structures – Interim Approval

The federal rules promulgated by the United States Environmental Protection Agency (USEPA) in 40 CFR Parts 122 and 125 establishing the requirements of section 316(b) of the Clean Water Act for Existing Facilities took effect October 14, 2014. Beginning October 14, 2014, any facility covered by the rules requesting permit reissuance shall submit an application in accordance with the rules and shall be subject to the best technology available (BTA) standards for impingement mortality and entrainment as defined in the rules. In accordance with 40 CFR 125.95(a)(2), the Department approved the permittee's March 10, 2016, request for an alternate schedule for submission of the information required in 40 CFR 122.21(r). The alternate schedule for submission of the reports identified in the request for is set for April 30, 2018 (received).

The cooling water intake structure operated by the permittee has been evaluated using all available information relating to its location, design, construction, and capacity. At this time, the Department has made an **interim** determination that the cooling water intake structure represents BTA to minimize adverse environmental impact in accordance with section 316(b) of the federal Clean Water Act (33 U.S.C. section 1326). The permittee shall at all times properly operate and maintain the cooling water intake structure and associated equipment to minimize adverse environmental impact. The permittee shall give advance notice to the Department of any planned changes in the location, design, operation, or capacity of the intake structure. If the Department determines that additional technologies or control measures are necessary to reduce the impact of impingement or entrainment, the Department may revise the requirements of this condition. Nothing in this permit shall either be construed to relieve the permittee from civil or criminal penalties for previous or future fish losses, or authorize take for the purposes of a facility's compliance with the Endangered Species Act.

#### 11. Facility Contact

The "Facility Contact" was specified in the application. The permittee may replace the facility contact at any time, and shall notify the Department in writing within 10 days after replacement (including the name, address and telephone number of the new facility contact).

- a. The facility contact shall be (or a duly authorized representative of this person):
  - for a corporation, a principal executive officer of at least the level of vice president; or a designated representative if the representative is responsible for the overall operation of the facility from which the discharge originates, as described in the permit application or other NPDES form,
  - for a partnership, a general partner,
  - for a sole proprietorship, the proprietor, or
  - for a municipal, state, or other public facility, either a principal executive officer, the mayor, village president, city or village manager or other duly authorized employee.
- b. A person is a duly authorized representative only if:
  - the authorization is made in writing to the Department by a person described in paragraph a. of this section; and
  - the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity such as the position of plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the facility (a duly authorized representative may thus be either a named individual or any individual occupying a named position).

Nothing in this section obviates the permittee from properly submitting reports and forms as required by law.

**PART I****Section A. Limitations and Monitoring Requirements****12. Discharge Monitoring Report – Quality Assurance Study Program**

The permittee shall participate in the Discharge Monitoring Report – Quality Assurance (DMR-QA) Study Program. The purpose of the DMR-QA Study Program is to annually evaluate the proficiency of all in-house and/or contract laboratory(ies) that perform, on behalf of the facility authorized to discharge under this permit, the analytical testing required under this permit. In accordance with Section 308 of the Clean Water Act (33 U.S.C. § 1318); and R 323.2138 and R 323.2154 of Part 21, Wastewater Discharge Permits, promulgated under Part 31 of the NREPA, participation in the DMR-QA Study Program is required for all major facilities, and for minor facilities selected for participation by the Department.

Annually and in accordance with DMR-QA Study Program requirements and submittal due dates, the permittee shall submit to the Michigan DMR-QA Study Program state coordinator all documentation required by the DMR-QA Study. DMR-QA Study Program participation is required only for the analytes required under this permit and only when those analytes are also identified in the DMR-QA Study.

If the permitted facility's status as a major facility should change, participation in the DMR-QA Study Program may be reevaluated. Questions concerning participation in the DMR-QA Study Program should be directed to the Michigan DMR-QA Study Program state coordinator.

All forms and instructions required for participation in the DMR-QA Study Program, including submittal due dates and state coordinator contact information, can be found at <http://www.epa.gov/compliance/discharge-monitoring-report-quality-assurance-study-program>.

**13. Schedule of Compliance for Bottom Ash Transport Water**

The permittee shall manage the discharge of bottom ash transport water (BATW) to surface waters of the state in accordance with EPA's Final Steam Electric Reconsideration Rule (Final Rule), effective October 13, 2020. This schedule of compliance (SOC) is based on two separate compliance pathways established by the Final Rule for BATW: the Cessation of Coal Burning Activities subcategory, and the implementation of an ELG-compliant technology. The permittee shall attain compliance with the Final Rule by completing the following requirements.

- a. On or before October 13, 2021, the permittee shall:
  - 1) submit a Notice of Planned Participation (NOPP) in the Cessation of Coal Burning Activities subcategory in accordance with 40 CFR §423.19 – if this compliance pathway is being considered, and/or
  - 2) submit an update on the feasibility evaluation to select an ELG-compliant technology – if this compliance pathway is being considered.
- b. On or before April 4, 2022, with the application for reissuance, the permittee shall submit a description of the ELG-compliant technology selected – if the ELG-compliant technology pathway is being considered.

**PART I****Section A. Limitations and Monitoring Requirements**

- c. On or before December 31, 2022, the permittee shall:
- 1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory – if this compliance pathway is being considered, and/or
  - 2) commence the engineering and design process for implementation of the selected ELG-compliant technology and submit a status report on this process – if this compliance pathway is being considered.
- d. On or before December 31, 2023, the permittee shall submit to the Department a report identifying the final pathway selected for compliance with the Final Rule: either the Cessation of Coal Burning Activities subcategory (including the annual progress report in accordance with 40 CFR §423.19), or the implementation of an ELG-compliant technology.
- e. On or before December 31, 2024, the permittee shall:
- 1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory – if this compliance pathway was selected, or
  - 2) continue construction of the selected ELG-compliant technology and submit a construction status report that includes a description of any impediments to final implementation by December 31, 2025 – if this compliance pathway was selected.
- f. On or before December 31, 2025, the permittee shall:
- 1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory – if this compliance pathway was selected, or
  - 2) submit an Initial Certification Statement in accordance with 40 CFR §423.19(c) and comply with the requirements set forth in Part I.A.14.b. of this permit – if the ELG-compliant technology pathway was selected.
- g. If the permittee selected the Cessation of Coal Burning Activities subcategory as the final pathway for compliance with the Final Rule, the permittee shall complete the following:
- 1) On or before December 31, 2026, the permittee shall submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory.
  - 2) On or before December 31, 2027, the permittee shall submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory.
  - 3) On or before December 31, 2028, the permittee shall comply with the requirements set forth in Part I.A.14.a. of this permit.

**PART I****Section A. Limitations and Monitoring Requirements****14. Bottom Ash Transport Water Discharge Prohibition**

- a. If the permittee has certified to the Department the intention to pursue the Cessation of Coal Burning Activities subcategory as set forth in Part I.A.13. of this permit, then the discharge of all BATW shall comply with the final effluent limitations set forth in Part I.A.2. and Part I.A.4. of this permit until no later than December 31, 2028, by which date the permittee shall cease discharge of newly generated BATW from any outfall and the discharge of previously generated BATW shall comply with the final effluent limitations set forth in Part I.A.2. and Part I.A.4. of this permit.
- b. Beginning December 31, 2025, the permittee is prohibited from discharging newly generated BATW from any outfall in accordance with 40 CFR 423.13(k)(1), except for those discharges to which paragraph (k)(2) applies. After December 31, 2025, any discharge volume of BATW shall be reduced or eliminated to the extent achievable using control measures that are technologically available and economically achievable in light of best industry practices. The total volume of BATW allowed to be discharged under (k)(2) shall be determined by the Department on a case-by-case basis and in no event shall such discharge exceed a 30-day rolling average of 10 percent of the primary active wetted bottom ash system volume. At least 180 days prior to the discharge of any newly generated BATW, the permittee shall submit to the Department all information required under 40 CFR 423.19(c) for reviews required under (k)(2).

The Department may modify or reissue this permit in accordance with applicable rules in order to establish the permit requirements set forth in the rules for 40 CFR Part 423, Steam Electric Power Generating Point Source Category.

**PART I****Section B. Storm Water Pollution Prevention****1. Final Effluent Limitations and Monitoring Requirements**

The permittee is authorized to discharge storm water associated with industrial activity, as defined under 40 CFR 122.26(b)(14)(i-ix), to the surface waters of the state. Such discharge shall be limited and monitored by the permittee as specified below.

- a. **Narrative Standard**  
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.
- b. **Visual Assessment of Storm Water Discharges**  
To ensure that storm water discharges from the facility do not violate the narrative standard in the receiving waters, storm water discharges shall be visually assessed in accordance with this permit.
- c. **Implementation of Storm Water Pollution Prevention Plan**  
The permittee shall implement an acceptable Storm Water Pollution Prevention Plan (SWPPP) as required by this permit.
- d. **Certified Operator**  
The permittee shall have an Industrial Storm Water Certified Operator who has supervision over the facility's storm water treatment and control measures included in the SWPPP.

## PART I

### Section B. Storm Water Pollution Prevention

*The Storm Water Pollution Prevention Plan (SWPPP) is a written procedure to reduce the exposure of storm water to significant materials and to reduce the amount of significant materials in the storm water discharge. An acceptable SWPPP shall identify potential sources of contamination and describe the controls necessary to reduce their impacts in accordance with Part I.B.2. through Part I.B.8. of this permit.*

#### 2. Source Identification

To identify potential sources of significant materials that can pollute storm water and subsequently be discharged from the facility, the SWPPP shall, at a minimum, include the following:

- a. A site map identifying:
  - 1) buildings and other permanent structures;
  - 2) storage or disposal areas for significant materials;
  - 3) secondary containment structures and descriptions of the significant materials contained within the primary containment structures;
  - 4) storm water discharge points (which include outfalls and points of discharge), numbered or otherwise labeled for reference;
  - 5) location of storm water and non-storm water inlets (numbered or otherwise labeled for reference) contributing to each discharge point;
  - 6) location of NPDES-permitted discharges other than storm water;
  - 7) outlines of the drainage areas contributing to each discharge point;
  - 8) structural controls or storm water treatment facilities;
  - 9) areas of vegetation (with brief descriptions such as lawn, old field, marsh, wooded, etc.);
  - 10) areas of exposed and/or erodible soils and gravel lots;
  - 11) impervious surfaces (e.g., roofs, asphalt, concrete, etc.);
  - 12) name and location of receiving water(s); and
  - 13) areas of known or suspected impacts on surface waters as designated under Part 201 (Environmental Response) of the NREPA.
- b. A list of all significant materials that could pollute storm water. For each material listed, the SWPPP shall include each of the following descriptions:
  - 1) the ways in which each type of significant material has been, or has reasonable potential to become, exposed to storm water (e.g., spillage during handling; leaks from pipes, pumps, and vessels; contact with storage piles, contaminated materials, or soils; waste handling and disposal; deposits from dust or overspray; etc.);

**PART I****Section B. Storm Water Pollution Prevention**

- 2) identification of the discharge point(s) and the inlet(s) contributing the significant material to each discharge point through which the significant material may be discharged if released; and
- 3) an evaluation of the reasonable potential for contribution of significant materials to storm water from at least the following areas or activities:
  - a) loading, unloading, and other significant material-handling operations;
  - b) outdoor storage, including secondary containment structures;
  - c) outdoor manufacturing or processing activities;
  - d) significant dust- or particulate-generating processes;
  - e) discharge from vents, stacks, and air emission controls;
  - f) on-site waste disposal practices;
  - g) maintenance and cleaning of vehicles, machines, and equipment;
  - h) areas of exposed and/or erodible soils;
  - i) Sites of Environmental Contamination listed under Part 201 (Environmental Response) of the NREPA;
  - j) areas of significant material residues;
  - k) areas where animals (wild or domestic) congregate and deposit wastes; and
  - l) other areas where storm water may come into contact with significant materials.
- c. A listing of significant spills and significant leaks of polluting materials that occurred in areas that are exposed to precipitation or that discharge to a point source at the facility. The listing shall include spills that occurred over the three (3) years prior to the effective date of a permit authorizing discharge. The listing shall include the date, volume, and exact location of the release, and the action taken to clean up the material and/or prevent exposure to storm water or contamination of surface waters of the state. Any release that occurs after the SWPPP has been developed shall be controlled in accordance with the SWPPP and is cause for the SWPPP to be updated as appropriate within 14 calendar days of obtaining knowledge of the spill or loss.
- d. A determination as to whether its facility discharges storm water to a water body for which an EPA-approved Total Maximum Daily Load (TMDL) has been established. If so, the permittee shall assess whether the TMDL requirements for the facility's discharge are being met through the existing SWPPP controls or whether additional control measures are necessary. The permittee's assessment of whether the TMDL requirements are being met shall focus on the effectiveness, adequacy, and implementation of the permittee's SWPPP controls.
- e. A summary of existing storm water discharge sampling data (if available), describing pollutants in storm water discharges at the facility. This summary shall be accompanied by a description of the suspected source(s) of the pollutants detected.

**PART I****Section B. Storm Water Pollution Prevention****3. Nonstructural Controls**

To prevent significant materials from contacting storm water at the source, the SWPPP shall, at a minimum, include each of the following nonstructural controls:

- a. Written procedures and a schedule for routine preventive maintenance. Preventive maintenance procedures shall describe routine inspections and maintenance of storm water management and control devices (e.g., cleaning of oil/water separators and catch basins, routine housekeeping activities, etc.), as well as inspecting and testing plant equipment and systems to uncover conditions that could cause breakdowns or failures resulting in discharges of pollutants to the storm sewer system or the surface waters of the state. The routine inspection shall include areas of the facility in which significant materials have the reasonable potential to contaminate storm water. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below.
- b. Written procedures and a schedule for good housekeeping to maintain a clean, orderly facility. Good housekeeping procedures shall include routine inspections that focus on the areas of the facility that have a reasonable potential to contaminate storm water entering the property. The routine housekeeping inspections may be combined with the routine inspections for the preventive maintenance program. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below.
- c. Written procedures and a schedule for **quarterly** comprehensive site inspections, to be conducted by the Industrial Storm Water Certified Operator. At a minimum, one inspection shall be performed within each of the following quarters: January-March, April-June, July-September, and October-December. The comprehensive site inspections shall include, but not be limited to, inspection of structural controls in use at the facility, and the areas and equipment identified in the routine preventive maintenance and good housekeeping procedures. These inspections shall also include a review of the routine preventive maintenance reports, good housekeeping inspection reports, and any other paperwork associated with the SWPPP. The permittee may request Department approval of an alternate schedule for comprehensive site inspections. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below, and the following shall be included on the comprehensive inspection form/report:
  - 1) Date of the inspection.
  - 2) Name(s), title(s), and certification number(s) of the personnel conducting the inspection.
  - 3) Precipitation information (i.e., a description of recent rainfall/snowmelt events).
  - 4) All observations relating to the implementation of control measures. Items to include if applicable:
    - a) updates on corrective actions implemented due to previously identified pollutant and/or discharge issues;
    - b) any evidence of, or the potential for, pollutants to discharge to the drainage system or receiving waters and the condition of and around the discharge point including flow dissipation measures needing maintenance or repairs;
    - c) any control measures needing maintenance or repairs; and
    - d) any additional control measures needed to comply with permit requirements.

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### Section B. Storm Water Pollution Prevention

- 5) Any required revisions to the SWPPP resulting from the inspection.
- 6) A written certification stating the facility is in compliance with this permit and the SWPPP, or, if there are instances of noncompliance, they are identified.
- 7) Written procedures and a schedule for **quarterly** visual assessments of storm water discharges. At a minimum, one visual assessment shall be conducted within each of the following quarters: January-March, April-June, July-September, and October-December. These assessments shall be conducted as part of the comprehensive site inspection within one month of control measure observations made in accordance with 4), above. If the Department has approved an alternate schedule for the comprehensive site inspection, the visual assessment may likewise be conducted in accordance with the same approved alternate schedule.

The following are the requirements of the visual assessment. The permittee shall develop and clearly document, in writing, procedures for meeting these requirements:

- a) Within six (6) months of the effective date of this permit, the permittee shall develop written procedures for conducting the visual assessment and incorporate these procedures into the SWPPP. If Qualified Personnel rather than an Industrial Storm Water Certified Operator will collect storm water samples, these procedures shall include a written description of the training given to these personnel to qualify them to collect the samples, as well as documentation verifying that these personnel have received this training. The first visual assessment shall be conducted in conjunction with the next occurring comprehensive inspection. If changes resulting in altered drainage patterns occur at the facility, the permittee shall modify the procedures for conducting the visual assessment in accordance with the requirements of Keeping SWPPPs Current, below, and these modifications shall be incorporated into the SWPPP prior to conducting the next visual assessment.
- b) A visual assessment shall be conducted of a representative storm water **sample** collected **from each storm water discharge point**. Storm water samples shall be visually assessed for conditions that could cause a violation of water quality standards as defined in Water Quality Standards, below. The visual assessment shall be made of the storm water sample in a clean, clear glass or plastic container. Only an Industrial Storm Water Certified Operator shall conduct this visual assessment. Visual assessment of the storm water sample shall be conducted within 48 hours of sample collection.

Representative storm water samples shall be collected:

- (1) from each storm water discharge point identified as set forth under Source Identification, above. These samples may be collected by one or more of the following: an Industrial Storm Water Certified Operator; and/or an individual who meets qualifications acceptable to the Department and who is authorized by an Industrial Storm Water Certified Operator to collect the sample ("Qualified Personnel"); and/or an automated sampling device; and
- (2) within the first 30 minutes of the start of a discharge from a storm event and on discharges that occur at least 72 hours (3 days) from the previous discharge. If it is not possible to collect the sample within the first 30 minutes of discharge, the sample shall be collected as soon thereafter as practicable, but not exceeding 60 minutes. In the case of snowmelt, samples shall be collected during a period with measurable discharge from the site.

**PART I****Section B. Storm Water Pollution Prevention**

- c) A visual assessment shall be conducted of the storm water **discharge at each storm water discharge point**. (If an automated sampling device is used to collect the storm water sample, this requirement is waived). Either an Industrial Storm Water Certified Operator and/or Qualified Personnel may conduct this visual assessment. This visual assessment may be conducted directly – by someone physically present at the storm water discharge at each storm water discharge point; or it may be conducted indirectly – through the use of a visual recording taken of the storm water discharge at each storm water discharge point. Direct visual assessment shall be conducted at the same time that the storm water sample is collected. Indirect visual assessment shall be conducted using a visual recording taken of the storm water discharge at the same time that the storm water sample was collected.
- d) Visual assessments shall be documented. This documentation shall be retained in accordance with Record Keeping, below, and shall include the following:
- (1) sampling location(s) at the storm water discharge point(s) identified on the site map (see Source Identification, above);
  - (2) storm event information (i.e., length of event expressed in hours, approximate size of event expressed in inches of precipitation, duration of time since previous event that caused a discharge, and date and time the discharge began);
  - (3) date and time of the visual assessment of each storm water **discharge** at each storm water discharge point;
  - (4) name(s) and title(s) of the Industrial Storm Water Certified Operator or Qualified Personnel who conducted the visual assessment of the storm water **discharge** at each storm water discharge point. If an automated sampling device was used to collect the storm water sample associated with this discharge point, this documentation requirement is waived;
  - (5) observations made during visual assessment of the storm water **discharge** at each storm water discharge point. If an automated sampling device was used to collect the storm water sample associated with this discharge point, this documentation requirement is waived;
  - (6) if applicable, any visual recordings used to conduct the visual assessment of the storm water **discharge** at each storm water discharge point;
  - (7) date and time of sample collection for each storm water **sample**;
  - (8) name(s) and title(s) of the Industrial Storm Water Certified Operator or Qualified Personnel who collected the storm water **sample**. If an automated sampling device was used to collect the storm water sample, the permittee shall document that, instead;
  - (9) date and time of the visual assessment of each storm water **sample**;
  - (10) name(s), title(s), and operator number(s) of the Industrial Storm Water Certified Operator(s) who conducted the visual assessment of each storm water **sample**;
  - (11) observations made during visual assessment of each storm water **sample**;

**PART I****Section B. Storm Water Pollution Prevention**

- (12) full-color photographic evidence of the storm water **sample** against a white background;
  - (13) nature of the discharge (i.e., rainfall or snowmelt);
  - (14) probable sources of any observed storm water contamination; and
  - (15) if applicable, an explanation for why it was not possible to collect samples within the first 30 minutes of discharge.
- e) When adverse weather conditions prevent a visual assessment during the quarter, a substitute visual assessment shall be conducted during the next qualifying storm event. Documentation of the rationale for no visual assessment during a quarter shall be included with the SWPPP records as described in Record Keeping, below. Adverse conditions are those that are dangerous or create inaccessibility for personnel, such as local flooding, high winds, electrical storms, or situations that otherwise make sampling impractical such as drought or extended frozen conditions.
  - f) If the facility has two (2) or more discharge points that are believed to discharge substantially identical storm water effluents, the facility may conduct visual assessments of the discharge at just one (1) of the discharge points and report that the results also apply to the other substantially identical discharge point(s). The determination of substantially identical discharge points is to be based on the significant material evaluation conducted as set forth under Source Identification, above, and shall be clearly documented in the SWPPP. Visual assessments shall be conducted on a rotating basis of each substantially identical discharge point throughout the period of coverage under this permit.
- d. A description of material handling procedures and storage requirements for significant materials. Equipment and procedures for cleaning up spills shall be identified in the SWPPP and made available to the appropriate personnel. The procedures shall identify measures to prevent spilled materials or material residues from contaminating storm water entering the property. The SWPPP shall include language describing what a reportable spill or release is and the appropriate reporting requirements in accordance with Part II.C.6. and Part II.C.7. The SWPPP may include, by reference, requirements of either a Pollution Incident Prevention Plan (PIPP) prepared in accordance with the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code); a Hazardous Waste Contingency Plan prepared in accordance with 40 CFR 264 and 265 Subpart D, as required by Part 111 of the NREPA; or a Spill Prevention Control and Countermeasure (SPCC) plan prepared in accordance with 40 CFR 112.
  - e. Identification of areas which, due to topography, activities, or other factors, have a high potential for significant soil erosion. Gravel lots shall be included. The SWPPP shall also identify measures used to control soil erosion and sedimentation.
  - f. A description of the employee training program that will be implemented on an annual basis to inform appropriate personnel at all levels of their responsibility as it relates to the components and goals of the SWPPP. The SWPPP shall identify periodic dates for the employee training program. Records of the employee training program shall be retained in accordance with Record Keeping, below.
  - g. Identification of actions to limit the discharge of significant materials in order to comply with TMDL requirements, if applicable.

## PART I

### Section B. Storm Water Pollution Prevention

- h. Identification of significant materials expected to be present in storm water discharges following implementation of nonstructural preventive measures and source controls.

#### 4. Structural Controls

Where implementation of the measures required by Nonstructural Controls, above, does not control storm water discharges in accordance with Water Quality Standards, below, the SWPPP shall provide a description of the location, function, design criteria, and installation/construction schedule of structural controls for prevention and treatment. Structural controls may be necessary:

- a. to prevent uncontaminated storm water from contacting, or being contacted by, significant materials; or
- b. if preventive measures are not feasible or are inadequate to keep significant materials at the site from contaminating storm water. Structural controls shall be used to treat, divert, isolate, recycle, reuse, or otherwise manage storm water in a manner that reduces the level of significant materials in the storm water and provides compliance with water quality standards as identified in Water Quality Standards, below.

#### 5. Keeping SWPPPs Current

- a. The permittee and/or the Industrial Storm Water Certified Operator shall review the SWPPP annually after it is developed and maintain a written report of the review in accordance with Record Keeping, below. Based on the review, the permittee or the Industrial Storm Water Certified Operator shall amend the SWPPP as needed to ensure continued compliance with the terms and conditions of this permit. The written report shall be submitted to the Department on or before January 10<sup>th</sup> of each year.
- b. The SWPPP developed under the conditions of a previous permit shall be amended as necessary to ensure compliance with this permit.
- c. The SWPPP shall be updated or amended whenever changes at the facility have the potential to increase the exposure of significant materials to storm water, significant spills occur at the facility, or when the SWPPP is determined by the permittee or the Department to be ineffective in achieving the general objectives of controlling pollutants in storm water discharges associated with industrial activity. Updates based on increased activity or spills at the facility shall include a description of how the permittee intends to control any new sources of significant materials, or respond to and prevent spills in accordance with the requirements of this permit (see Source Identification; Nonstructural Controls; and Structural Controls, above).
- d. The Department may notify the permittee at any time that the SWPPP does not meet minimum requirements of this permit. Such notification shall identify why the SWPPP does not meet minimum requirements of this permit. The permittee shall make the required changes to the SWPPP within 30 days after such notification from the Department or authorized representative and shall submit to the Department a written certification that the requested changes have been made.
- e. Amendments to the SWPPP shall be signed and retained on-site with the SWPPP pursuant to Signature and SWPPP Review, below.

**PART I****Section B. Storm Water Pollution Prevention****6. Industrial Storm Water Certified Operator Update**

If the Industrial Storm Water Certified Operator is changed or an Industrial Storm Water Certified Operator is added, the permittee shall provide the name and certification number of the new Industrial Storm Water Certified Operator to the Department. If a facility has multiple Industrial Storm Water Certified Operators, the names and certification numbers of all shall be included in the SWPPP.

**7. Signature and SWPPP Review**

- a. The SWPPP shall be reviewed and signed by the Industrial Storm Water Certified Operator(s) and by either the permittee or an authorized representative in accordance with 40 CFR 122.22. The SWPPP and associated records shall be retained on-site at the facility that generates the storm water discharge.
- b. The permittee shall make the SWPPP, reports, log books, storm water discharge sampling data (if collected), and items required by Record Keeping, below, available upon request to the Department. The Department makes the non-confidential business portions of the SWPPP available to the public.

**8. Record Keeping**

The permittee shall maintain records of all SWPPP-related inspection and maintenance activities. Records shall also be kept describing incidents such as spills or other discharges that can affect the quality of storm water. All such records shall be retained for three (3) years. The following records are required by this permit (see Nonstructural Controls; and Keeping SWPPPs Current, above):

- a. routine preventive maintenance inspection reports;
- b. routine good housekeeping inspection reports;
- c. comprehensive site inspection reports;
- d. documentation of visual assessments;
- e. employee training records; and
- f. written summaries of the annual SWPPP review.

**PART I****Section B. Storm Water Pollution Prevention****9. Water Quality Standards**

At the time of discharge, there shall be no violation of water quality standards in the receiving waters as a result of the storm water discharge. This requirement includes, but is not limited to, the following conditions:

- a. In accordance with R 323.1050 of the Part 4 Rules promulgated pursuant to Part 31 of the NREPA, the receiving waters shall not have any of the following unnatural physical properties as a result of this discharge in quantities which are, or may become, injurious to any designated use: turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits.
- b. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended solids, or deposits) shall be reported within 24 hours to the Department, followed by a written report within five (5) days detailing the findings of the investigation and the steps taken to correct the condition.
- c. Any pollutant for which a level of control is specified to meet a TMDL established by the Department shall be controlled at the facility so that its discharge is reduced by/to the amount specified in the TMDL.

**PART I****Section B. Storm Water Pollution Prevention****10. Prohibition of Non-Storm Water Discharges**

Discharges of material other than storm water shall be in compliance with an NPDES permit issued for the discharge. Storm water shall be defined to include all of the following non-storm water discharges, provided pollution prevention controls for the non-storm water component are identified in the SWPPP:

- a. discharges from fire hydrant flushing;
- b. potable water sources, including water line flushing;
- c. water from fire system testing and fire-fighting training without burned materials or chemical fire suppressants;
- d. irrigation drainage;
- e. lawn watering;
- f. routine building wash-down that does not use detergents or other compounds;
- g. pavement wash waters where contamination by toxic or hazardous materials has not occurred (unless all contamination by toxic or hazardous materials has been removed) and where detergents are not used;
- h. uncontaminated condensate from air conditioners, coolers, and other compressors and from the outside storage of refrigerated gases or liquids;
- i. springs;
- j. uncontaminated groundwater;
- k. foundation or footing drains where flows are not contaminated with process materials such as solvents; and
- l. discharges from fire-fighting activities. Discharges from fire-fighting activities are exempted from the requirement to be identified in the SWPPP.

**11. Tracer Dye Discharges**

This permit does not authorize the discharge of tracer dyes without approval from the Department. Requests to discharge tracer dyes shall be submitted to the Department in accordance with Rule 1097 (R 323.1097 of the Michigan Administrative Code).

## PART II

Part II may include terms and /or conditions not applicable to discharges covered under this permit.

### Section A. Definitions

**Acute toxic unit (TU<sub>A</sub>)** means  $100/LC_{50}$  where the  $LC_{50}$  is determined from a whole effluent toxicity (WET) test which produces a result that is statistically or graphically estimated to be lethal to 50% of the test organisms.

**Annual monitoring frequency** refers to a calendar year beginning on January 1 and ending on December 31. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

**Authorized public agency** means a state, local, or county agency that is designated pursuant to the provisions of section 9110 of Part 91 of the NREPA to implement soil erosion and sedimentation control requirements with regard to construction activities undertaken by that agency.

**Best management practices (BMPs)** means structural devices or nonstructural practices that are designed to prevent pollutants from entering into storm water, to direct the flow of storm water, or to treat polluted storm water.

**Bioaccumulative chemical of concern (BCC)** means a chemical which, upon entering the surface waters, by itself or as its toxic transformation product, accumulates in aquatic organisms by a human health bioaccumulation factor of more than 1000 after considering metabolism and other physiochemical properties that might enhance or inhibit bioaccumulation. The human health bioaccumulation factor shall be derived according to R 323.1057(5). Chemicals with half-lives of less than 8 weeks in the water column, sediment, and biota are not BCCs. The minimum bioaccumulation concentration factor (BAF) information needed to define an organic chemical as a BCC is either a field-measured BAF or a BAF derived using the biota-sediment accumulation factor (BSAF) methodology. The minimum BAF information needed to define an inorganic chemical as a BCC, including an organometal, is either a field-measured BAF or a laboratory-measured bioconcentration factor (BCF). The BCCs to which these rules apply are identified in Table 5 of R 323.1057 of the Water Quality Standards.

**Biosolids** are the solid, semisolid, or liquid residues generated during the treatment of sanitary sewage or domestic sewage in a treatment works. This includes, but is not limited to, scum or solids removed in primary, secondary, or advanced wastewater treatment processes and a derivative of the removed scum or solids.

**Bulk biosolids** means biosolids that are not sold or given away in a bag or other container for application to a lawn or home garden.

**Certificate of Coverage (COC)** is a document, issued by the Department, which authorizes a discharge under a general permit.

**Chronic toxic unit (TU<sub>C</sub>)** means  $100/MATC$  or  $100/IC_{25}$ , where the maximum acceptable toxicant concentration (MATC) and  $IC_{25}$  are expressed as a percent effluent in the test medium.

**Class B biosolids** refers to material that has met the Class B pathogen reduction requirements or equivalent treatment by a Process to Significantly Reduce Pathogens (PSRP) in accordance with the Part 24 Rules. Processes include aerobic digestion, composting, anaerobic digestion, lime stabilization and air drying.

**Combined sewer system** is a sewer system in which storm water runoff is combined with sanitary wastes.

## PART II

### Section A. Definitions

**Daily concentration** is the sum of the concentrations of the individual samples of a parameter divided by the number of samples taken during any calendar day. If the parameter concentration in any sample is less than the quantification limit, regard that value as zero when calculating the daily concentration. The daily concentration will be used to determine compliance with any maximum and minimum daily concentration limitations (except for pH and dissolved oxygen). When required by the permit, report the maximum calculated daily concentration for the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the Discharge Monitoring Reports (DMRs).

For pH, report the maximum value of any *individual* sample taken during the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs and the minimum value of any *individual* sample taken during the month in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs. For dissolved oxygen, report the minimum concentration of any *individual* sample in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs.

**Daily loading** is the total discharge by weight of a parameter discharged during any calendar day. This value is calculated by multiplying the daily concentration by the total daily flow and by the appropriate conversion factor. The daily loading will be used to determine compliance with any maximum daily loading limitations. When required by the permit, report the maximum calculated daily loading for the month in the "MAXIMUM" column under "QUANTITY OR LOADING" on the DMRs.

**Daily monitoring frequency** refers to a 24-hour day. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

**Department** means the Michigan Department of Environment, Great Lakes, and Energy.

**Detection level** means the lowest concentration or amount of the target analyte that can be determined to be different from zero by a single measurement at a stated level of probability.

**Discharge** means the addition of any waste, waste effluent, wastewater, pollutant, or any combination thereof to any surface water of the state.

**EC<sub>50</sub>** means a statistically or graphically estimated concentration that is expected to cause 1 or more specified effects in 50% of a group of organisms under specified conditions.

#### **Fecal coliform bacteria monthly**

FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – Fecal coliform bacteria monthly is the geometric mean of all daily concentrations determined during a discharge event. Days on which no daily concentration is determined shall not be used to determine the calculated monthly value. The calculated monthly value will be used to determine compliance with the maximum monthly fecal coliform bacteria limitations. When required by the permit, report the calculated monthly value in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR. If the period in which the discharge event occurred was partially in each of two months, the calculated monthly value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – Fecal coliform bacteria monthly is the geometric mean of all daily concentrations determined during a reporting month. Days on which no daily concentration is determined shall not be used to determine the calculated monthly value. The calculated monthly value will be used to determine compliance with the maximum monthly fecal coliform bacteria limitations. When required by the permit, report the calculated monthly value in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR.

## PART II

### Section A. Definitions

#### **Fecal coliform bacteria 7-day**

FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – Fecal coliform bacteria 7-day is the geometric mean of the daily concentrations determined during any 7 consecutive days of discharge during a discharge event. If the number of daily concentrations determined during the discharge event is less than 7 days, the number of actual daily concentrations determined shall be used for the calculation. Days on which no daily concentration is determined shall not be used to determine the value. The calculated 7-day value will be used to determine compliance with the maximum 7-day fecal coliform bacteria limitations. When required by the permit, report the maximum calculated 7-day geometric mean value for the month in the “MAXIMUM” column under “QUALITY OR CONCENTRATION” on the DMRs. If the 7-day period was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – Fecal coliform bacteria 7-day is the geometric mean of the daily concentrations determined during any 7 consecutive days in a reporting month. If the number of daily concentrations determined is less than 7, the actual number of daily concentrations determined shall be used for the calculation. Days on which no daily concentration is determined shall not be used to determine the value. The calculated 7-day value will be used to determine compliance with the maximum 7-day fecal coliform bacteria limitations. When required by the permit, report the maximum calculated 7-day geometric mean for the month in the “MAXIMUM” column under “QUALITY OR CONCENTRATION” on the DMRs. The first calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

**Flow-proportioned sample** is a composite sample with the sample volume proportional to the effluent flow.

**General permit** means a National Pollutant Discharge Elimination System permit issued authorizing a category of similar discharges.

**Geometric mean** is the average of the logarithmic values of a base 10 data set, converted back to a base 10 number.

**Grab sample** is a single sample taken at neither a set time nor flow.

**IC<sub>25</sub>** means the toxicant concentration that would cause a 25% reduction in a nonquantal biological measurement for the test population.

**Illicit connection** means a physical connection to a municipal separate storm sewer system that primarily conveys non-storm water discharges other than uncontaminated groundwater into the storm sewer; or a physical connection not authorized or permitted by the local authority, where a local authority requires authorization or a permit for physical connections.

**Illicit discharge** means any discharge to, or seepage into, a municipal separate storm sewer system that is not composed entirely of storm water or uncontaminated groundwater. Illicit discharges include non-storm water discharges through pipes or other physical connections; dumping of motor vehicle fluids, household hazardous wastes, domestic animal wastes, or litter; collection and intentional dumping of grass clippings or leaf litter; or unauthorized discharges of sewage, industrial waste, restaurant wastes, or any other non-storm water waste directly into a separate storm sewer.

**Individual permit** means a site-specific NPDES permit.

**Inlet** means a catch basin, roof drain, conduit, drain tile, retention pond riser pipe, sump pump, or other point where storm water or wastewater enters into a closed conveyance system prior to discharge off site or into waters of the state.

## PART II

### Section A. Definitions

**Interference** is a discharge which, alone or in conjunction with a discharge or discharges from other sources, both: 1) inhibits or disrupts the POTW, its treatment processes or operations, or its sludge processes, use or disposal; and 2) therefore, is a cause of a violation of any requirement of the POTW's NPDES permit (including an increase in the magnitude or duration of a violation) or, of the prevention of sewage sludge use or disposal in compliance with the following statutory provisions and regulations or permits issued thereunder (or more stringent state or local regulations): Section 405 of the Clean Water Act, the Solid Waste Disposal Act (SWDA) (including Title II, more commonly referred to as the Resource Conservation and Recovery Act (RCRA), and including state regulations contained in any state sludge management plan prepared pursuant to Subtitle D of the SWDA), the Clean Air Act, the Toxic Substances Control Act, and the Marine Protection, Research and Sanctuaries Act. [This definition does not apply to sample matrix interference].

**Land application** means spraying or spreading biosolids or a biosolids derivative onto the land surface, injecting below the land surface, or incorporating into the soil so that the biosolids or biosolids derivative can either condition the soil or fertilize crops or vegetation grown in the soil.

**LC<sub>50</sub>** means a statistically or graphically estimated concentration that is expected to be lethal to 50% of a group of organisms under specified conditions.

**Maximum acceptable toxicant concentration (MATC)** means the concentration obtained by calculating the geometric mean of the lower and upper chronic limits from a chronic test. A lower chronic limit is the highest tested concentration that did not cause the occurrence of a specific adverse effect. An upper chronic limit is the lowest tested concentration which did cause the occurrence of a specific adverse effect and above which all tested concentrations caused such an occurrence.

**Maximum extent practicable** means implementation of best management practices by a public body to comply with an approved storm water management program as required by a national permit for a municipal separate storm sewer system, in a manner that is environmentally beneficial, technically feasible, and within the public body's legal authority.

**MGD** means million gallons per day.

**Monthly concentration** is the sum of the daily concentrations determined during a reporting period divided by the number of daily concentrations determined. The calculated monthly concentration will be used to determine compliance with any maximum monthly concentration limitations. Days with no discharge shall not be used to determine the value. When required by the permit, report the calculated monthly concentration in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR.

For minimum percent removal requirements, the monthly influent concentration and the monthly effluent concentration shall be determined. The calculated monthly percent removal, which is equal to 100 times the quantity [1 minus the quantity (monthly effluent concentration divided by the monthly influent concentration)], shall be reported in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs.

**Monthly loading** is the sum of the daily loadings of a parameter divided by the number of daily loadings determined during a reporting period. The calculated monthly loading will be used to determine compliance with any maximum monthly loading limitations. Days with no discharge shall not be used to determine the value. When required by the permit, report the calculated monthly loading in the "AVERAGE" column under "QUANTITY OR LOADING" on the DMR.

**Monthly monitoring frequency** refers to a calendar month. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

## PART II

### Section A. Definitions

**Municipal separate storm sewer** means a conveyance or system of conveyances designed or used for collecting or conveying storm water which is not a combined sewer and which is not part of a publicly-owned treatment works as defined in the Code of Federal Regulations at 40 CFR 122.2.

**Municipal separate storm sewer system (MS4)** means all separate storm sewers that are owned or operated by the United States, a state, city, village, township, county, district, association, or other public body created by or pursuant to state law, having jurisdiction over disposal of sewage, industrial wastes, storm water, or other wastes, including special districts under state law, such as a sewer district, flood control district, or drainage district, or similar entity, or a designated or approved management agency under Section 208 of the Federal Act that discharges to the waters of the state. This term includes systems similar to separate storm sewer systems in municipalities, such as systems at military bases, large hospital or prison complexes, and highways and other thoroughfares. The term does not include separate storm sewers in very discrete areas, such as individual buildings.

**National Pretreatment Standards** are the regulations promulgated by or to be promulgated by the Federal Environmental Protection Agency pursuant to Section 307(b) and (c) of the Federal Act. The standards establish nationwide limits for specific industrial categories for discharge to a POTW.

**No observed adverse effect level (NOAEL)** means the highest tested dose or concentration of a substance which results in no observed adverse effect in exposed test organisms where higher doses or concentrations result in an adverse effect.

**Noncontact cooling water** is water used for cooling which does not come into direct contact with any raw material, intermediate product, by-product, waste product or finished product.

**Nondomestic user** is any discharger to a POTW that discharges wastes other than or in addition to water-carried wastes from toilet, kitchen, laundry, bathing or other facilities used for household purposes.

**Outfall** is the location at which a point source discharge enters the surface waters of the state.

**Part 91 agency** means an agency that is designated by a county board of commissioners pursuant to the provisions of section 9105 of Part 91 of the NREPA; an agency that is designated by a city, village, or township in accordance with the provisions of section 9106 of Part 91 of the NREPA; or the Department for soil erosion and sedimentation activities under Part 615, Part 631, or Part 632 pursuant to the provisions of section 9115 of Part 91 of the NREPA.

**Part 91 permit** means a soil erosion and sedimentation control permit issued by a Part 91 agency pursuant to the provisions of Part 91 of the NREPA.

**Partially treated sewage** is any sewage, sewage and storm water, or sewage and wastewater, from domestic or industrial sources that is treated to a level less than that required by the permittee's National Pollutant Discharge Elimination System permit, or that is not treated to national secondary treatment standards for wastewater, including discharges to surface waters from retention treatment facilities.

**Point of discharge** is the location of a point source discharge where storm water is discharged directly into a separate storm sewer system.

**Point source discharge** means a discharge from any discernible, confined, discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, or rolling stock. Changing the surface of land or establishing grading patterns on land will result in a point source discharge where the runoff from the site is ultimately discharged to waters of the state.

**Polluting material** means any material, in solid or liquid form, identified as a polluting material under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code).

## PART II

### Section A. Definitions

**POTW** is a publicly owned treatment work.

**Pretreatment** is reducing the amount of pollutants, eliminating pollutants, or altering the nature of pollutant properties to a less harmful state prior to discharge into a public sewer. The reduction or alteration can be by physical, chemical, or biological processes, process changes, or by other means. Dilution is not considered pretreatment unless expressly authorized by an applicable National Pretreatment Standard for a particular industrial category.

**Public** (as used in the MS4 individual permit) means all persons who potentially could affect the authorized storm water discharges, including, but not limited to, residents, visitors to the area, public employees, businesses, industries, and construction contractors and developers.

**Public body** means the United States; the state of Michigan; a city, village, township, county, school district, public college or university, or single-purpose governmental agency; or any other body which is created by federal or state statute or law.

**Qualified Personnel** means an individual who meets qualifications acceptable to the Department and who is authorized by an Industrial Storm Water Certified Operator to collect the storm water sample.

**Qualifying storm event** means a storm event causing greater than 0.1 inch of rainfall and occurring at least 72 hours after the previous measurable storm event that also caused greater than 0.1 inch of rainfall. Upon request, the Department may approve an alternate definition meeting the condition of a qualifying storm event.

**Quantification level** means the measurement of the concentration of a contaminant obtained by using a specified laboratory procedure calculated at a specified concentration above the detection level. It is considered the lowest concentration at which a particular contaminant can be quantitatively measured using a specified laboratory procedure for monitoring of the contaminant.

**Quarterly monitoring frequency** refers to a three month period, defined as January through March, April through June, July through September, and October through December. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

**Regional Administrator** is the Region 5 Administrator, U.S. EPA, located at R-19J, 77 W. Jackson Blvd., Chicago, Illinois 60604.

**Regulated area** means the permittee's urbanized area, where urbanized area is defined as a place and its adjacent densely-populated territory that together have a minimum population of 50,000 people as defined by the United States Bureau of the Census and as determined by the latest available decennial census.

**Secondary containment structure** means a unit, other than the primary container, in which significant materials are packaged or held, which is required by State or Federal law to prevent the escape of significant materials by gravity into sewers, drains, or otherwise directly or indirectly into any sewer system or to the surface or ground waters of this state.

**Separate storm sewer system** means a system of drainage, including, but not limited to, roads, catch basins, curbs, gutters, parking lots, ditches, conduits, pumping devices, or man-made channels, which is not a combined sewer where storm water mixes with sanitary wastes, and is not part of a POTW.

**Significant industrial user** is a nondomestic user that: 1) is subject to Categorical Pretreatment Standards under 40 CFR 403.6 and 40 CFR Chapter I, Subchapter N; or 2) discharges an average of 25,000 gallons per day or more of process wastewater to a POTW (excluding sanitary, noncontact cooling and boiler blowdown wastewater); contributes a process waste stream which makes up five (5) percent or more of the average dry weather hydraulic or organic capacity of the POTW treatment plant; or is designated as such by the permittee as defined in 40 CFR 403.12(a) on the basis that the industrial user has a reasonable potential for adversely

## PART II

### Section A. Definitions

affecting the POTW's treatment plant operation or violating any pretreatment standard or requirement (in accordance with 40 CFR 403.8(f)(6)).

**Significant materials** Significant Materials means any material which could degrade or impair water quality, including but not limited to: raw materials; fuels; solvents, detergents, and plastic pellets; finished materials such as metallic products; hazardous substances designated under Section 101(14) of Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) (see 40 CFR 372.65); any chemical the facility is required to report pursuant to Section 313 of Emergency Planning and Community Right-to-Know Act (EPCRA); polluting materials as identified under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code); Hazardous Wastes as defined in Part 111 of the NREPA; fertilizers; pesticides; and waste products such as ashes, slag, and sludge that have the potential to be released with storm water discharges.

**Significant spills and significant leaks** means any release of a polluting material reportable under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code).

**Special-use area** means secondary containment structures required by state or federal law; lands on Michigan's List of Sites of Environmental Contamination pursuant to Part 201, Environmental Remediation, of the NREPA; and/or areas with other activities that may contribute pollutants to the storm water for which the Department determines monitoring is needed.

**Stoichiometric** means the quantity of a reagent calculated to be necessary and sufficient for a given chemical reaction.

**Storm water** means storm water runoff, snow melt runoff, surface runoff and drainage, and non-storm water included under the conditions of this permit.

**Storm water discharge point** is the location where the point source discharge of storm water is directed to surface waters of the state or to a separate storm sewer. It includes the location of all point source discharges where storm water exits the facility, including *outfalls* which discharge directly to surface waters of the state, and *points of discharge* which discharge directly into separate storm sewer systems.

**SWPPP** means the Storm Water Pollution Prevention Plan prepared in accordance with this permit.

**Tier I value** means a value for aquatic life, human health or wildlife calculated under R 323.1057 of the Water Quality Standards using a tier I toxicity database.

**Tier II value** means a value for aquatic life, human health or wildlife calculated under R 323.1057 of the Water Quality Standards using a tier II toxicity database.

**Total maximum daily loads (TMDLs)** are required by the Federal Act for waterbodies that do not meet water quality standards. TMDLs represent the maximum daily load of a pollutant that a waterbody can assimilate and meet water quality standards, and an allocation of that load among point sources, nonpoint sources, and a margin of safety.

**Toxicity reduction evaluation (TRE)** means a site-specific study conducted in a stepwise process designed to identify the causative agents of effluent toxicity, isolate the sources of toxicity, evaluate the effectiveness of toxicity control options, and then confirm the reduction in effluent toxicity.

**Water Quality Standards** means the Part 4 Water Quality Standards promulgated pursuant to Part 31 of the NREPA, being R 323.1041 through R 323.1117 of the Michigan Administrative Code.

## PART II

### Section A. Definitions

**Weekly monitoring frequency** refers to a calendar week which begins on Sunday and ends on Saturday. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

**WWSL** is a wastewater stabilization lagoon.

**WWSL discharge event** is a discrete occurrence during which effluent is discharged to the surface water up to 10 days of a consecutive 14 day period.

**3-portion composite sample** is a sample consisting of three equal-volume grab samples collected at equal intervals over an 8-hour period.

#### **7-day concentration**

FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – The 7-day concentration is the sum of the daily concentrations determined during any 7 consecutive days of discharge during a WWSL discharge event divided by the number of daily concentrations determined. If the number of daily concentrations determined during the WWSL discharge event is less than 7 days, the number of actual daily concentrations determined shall be used for the calculation. The calculated 7-day concentration will be used to determine compliance with any maximum 7-day concentration limitations. When required by the permit, report the maximum calculated 7-day concentration for the WWSL discharge event in the “MAXIMUM” column under “QUALITY OR CONCENTRATION” on the DMR. If the WWSL discharge event was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – The 7-day concentration is the sum of the daily concentrations determined during any 7 consecutive days in a reporting month divided by the number of daily concentrations determined. If the number of daily concentrations determined is less than 7, the actual number of daily concentrations determined shall be used for the calculation. The calculated 7-day concentration will be used to determine compliance with any maximum 7-day concentration limitations in the reporting month. When required by the permit, report the maximum calculated 7-day concentration for the month in the “MAXIMUM” column under “QUALITY OR CONCENTRATION” on the DMR. The first 7-day calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

## PART II

### Section A. Definitions

#### **7-day loading**

FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – The 7-day loading is the sum of the daily loadings determined during any 7 consecutive days of discharge during a WWSL discharge event divided by the number of daily loadings determined. If the number of daily loadings determined during the WWSL discharge event is less than 7 days, the number of actual daily loadings determined shall be used for the calculation. The calculated 7-day loading will be used to determine compliance with any maximum 7-day loading limitations. When required by the permit, report the maximum calculated 7-day loading for the WWSL discharge event in the “MAXIMUM” column under “QUANTITY OR LOADING” on the DMR. If the WWSL discharge event was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred

FOR ALL OTHER DISCHARGES – The 7-day loading is the sum of the daily loadings determined during any 7 consecutive days in a reporting month divided by the number of daily loadings determined. If the number of daily loadings determined is less than 7, the actual number of daily loadings determined shall be used for the calculation. The calculated 7-day loading will be used to determine compliance with any maximum 7-day loading limitations in the reporting month. When required by the permit, report the maximum calculated 7-day loading for the month in the “MAXIMUM” column under “QUANTITY OR LOADING” on the DMR. The first 7-day calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

**24-hour composite sample** is a flow-proportioned composite sample consisting of hourly or more frequent portions that are taken over a 24-hour period. A time-proportioned composite sample may be used upon approval of the Department if the permittee demonstrates it is representative of the discharge.

## PART II

### Section B. Monitoring Procedures

#### 1. Representative Samples

Samples and measurements taken as required herein shall be representative of the volume and nature of the monitored discharge.

#### 2. Test Procedures

Test procedures for the analysis of pollutants shall conform to regulations promulgated pursuant to Section 304(h) of the Federal Act (40 CFR Part 136 – Guidelines Establishing Test Procedures for the Analysis of Pollutants), unless specified otherwise in this permit. **Test procedures used shall be sufficiently sensitive to determine compliance with applicable effluent limitations.** Requests to use test procedures not promulgated under 40 CFR Part 136 for pollutant monitoring required by this permit shall be made in accordance with the Alternate Test Procedures regulations specified in 40 CFR 136.4. These requests shall be submitted to the Section Manager of the Permits Section, Water Resources Division, Michigan Department of Environment, Great Lakes, and Energy, P.O. Box 30458, Lansing, Michigan, 48909-7958. The permittee may use such procedures upon approval.

The permittee shall periodically calibrate and perform maintenance procedures on all analytical instrumentation at intervals to ensure accuracy of measurements. The calibration and maintenance shall be performed as part of the permittee's laboratory Quality Control/Quality Assurance program.

#### 3. Instrumentation

The permittee shall periodically calibrate and perform maintenance procedures on all monitoring instrumentation at intervals to ensure accuracy of measurements.

#### 4. Recording Results

For each measurement or sample taken pursuant to the requirements of this permit, the permittee shall record the following information: 1) the exact place, date, and time of measurement or sampling; 2) the person(s) who performed the measurement or sample collection; 3) the dates the analyses were performed; 4) the person(s) who performed the analyses; 5) the analytical techniques or methods used; 6) the date of and person responsible for equipment calibration; and 7) the results of all required analyses.

#### 5. Records Retention

All records and information resulting from the monitoring activities required by this permit including all records of analyses performed and calibration and maintenance of instrumentation and recordings from continuous monitoring instrumentation shall be retained for a minimum of three (3) years, or longer if requested by the Regional Administrator or the Department.

## PART II

### Section C. Reporting Requirements

#### 1. Start-up Notification

If the permittee will not discharge during the first 60 days following the effective date of this permit, the permittee shall notify the Department within 14 days following the effective date of this permit, and then 60 days prior to the commencement of the discharge.

#### 2. Submittal Requirements for Self-Monitoring Data

Part 31 of the NREPA (specifically Section 324.3110(7)); and R 323.2155(2) of Part 21, Wastewater Discharge Permits, promulgated under Part 31 of the NREPA, allow the Department to specify the forms to be utilized for reporting the required self-monitoring data. Unless instructed on the effluent limitations page to conduct "Retained Self-Monitoring," the permittee shall submit self-monitoring data via the Department's MiWaters system.

The permittee shall utilize the information provided on the MiWaters website, located at <https://miwaters.deq.state.mi.us>, to access and submit the electronic forms. Both monthly summary and daily data shall be submitted to the Department no later than the 20<sup>th</sup> day of the month following each month of the authorized discharge period(s). The permittee may be allowed to submit the electronic forms after this date if the Department has granted an extension to the submittal date.

#### 3. Retained Self-Monitoring Requirements

If instructed on the effluent limits page (or otherwise authorized by the Department in accordance with the provisions of this permit) to conduct retained self-monitoring, the permittee shall maintain a year-to-date log of retained self-monitoring results and, upon request, provide such log for inspection to the staff of the Department. Retained self-monitoring results are public information and shall be promptly provided to the public upon request.

The permittee shall certify, in writing, to the Department, on or before January 10th (April 1st for animal feeding operation facilities) of each year, that: 1) all retained self-monitoring requirements have been complied with and a year-to-date log has been maintained; and 2) the application on which this permit is based still accurately describes the discharge. With this annual certification, the permittee shall submit a summary of the previous year's monitoring data. The summary shall include maximum values for samples to be reported as daily maximums and/or monthly maximums and minimum values for any daily minimum samples.

Retained self-monitoring may be denied to a permittee by notification in writing from the Department. In such cases, the permittee shall submit self-monitoring data in accordance with Part II.C.2., above. Such a denial may be rescinded by the Department upon written notification to the permittee. Reissuance or modification of this permit or reissuance or modification of an individual permittee's authorization to discharge shall not affect previous approval or denial for retained self-monitoring unless the Department provides notification in writing to the permittee.

#### 4. Additional Monitoring by Permittee

If the permittee monitors any pollutant at the location(s) designated herein more frequently than required by this permit, using approved analytical methods as specified above, the results of such monitoring shall be included in the calculation and reporting of the values required in the Discharge Monitoring Report. Such increased frequency shall also be indicated.

## PART II

### Section C. Reporting Requirements

Monitoring required pursuant to Part 41 of the NREPA or Rule 35 of the Mobile Home Park Commission Act (Act 96 of the Public Acts of 1987) for assurance of proper facility operation shall be submitted as required by the Department.

#### 5. Compliance Dates Notification

Within 14 days of every compliance date specified in this permit, the permittee shall submit a *written* notification to the Department indicating whether or not the particular requirement was accomplished. If the requirement was not accomplished, the notification shall include an explanation of the failure to accomplish the requirement, actions taken or planned by the permittee to correct the situation, and an estimate of when the requirement will be accomplished. If a written report is required to be submitted by a specified date and the permittee accomplishes this, a separate written notification is not required.

#### 6. Noncompliance Notification

Compliance with all applicable requirements set forth in the Federal Act, Parts 31 and 41 of the NREPA, and related regulations and rules is required. All instances of noncompliance shall be reported as follows:

- a. 24-Hour Reporting  
Any noncompliance which may endanger health or the environment (including maximum and/or minimum daily concentration discharge limitation exceedances) shall be reported, verbally, within 24 hours from the time the permittee becomes aware of the noncompliance. A written submission shall also be provided within five (5) days.
- b. Other Reporting  
The permittee shall report, in writing, all other instances of noncompliance not described in a. above at the time monitoring reports are submitted; or, in the case of retained self-monitoring, within five (5) days from the time the permittee becomes aware of the noncompliance.

Written reporting shall include: 1) a description of the discharge and cause of noncompliance; and 2) the period of noncompliance, including exact dates and times, or, if not yet corrected, the anticipated time the noncompliance is expected to continue, and the steps taken to reduce, eliminate and prevent recurrence of the noncomplying discharge.

#### 7. Spill Notification

The permittee shall immediately report any release of any polluting material which occurs to the surface waters or groundwaters of the state, unless the permittee has determined that the release is not in excess of the threshold reporting quantities specified in the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code), by calling the Department at the number indicated on the second page of this permit (or, if this is a general permit, on the COC); or, if the notice is provided after regular working hours, call the Department's 24-hour Pollution Emergency Alerting System telephone number, 1-800-292-4706 (calls from **out-of-state** dial 1-517-373-7660).

Within ten (10) days of the release, the permittee shall submit to the Department a full written explanation as to the cause of the release, the discovery of the release, response (clean-up and/or recovery) measures taken, and preventive measures taken or a schedule for completion of measures to be taken to prevent reoccurrence of similar releases.

## PART II

### Section C. Reporting Requirements

#### 8. Upset Noncompliance Notification

If a process "upset" (defined as an exceptional incident in which there is unintentional and temporary noncompliance with technology based permit effluent limitations because of factors beyond the reasonable control of the permittee) has occurred, the permittee who wishes to establish the affirmative defense of upset, shall notify the Department by telephone within 24 hours of becoming aware of such conditions; and within five (5) days, provide in writing, the following information:

- a. that an upset occurred and that the permittee can identify the specific cause(s) of the upset;
- b. that the permitted wastewater treatment facility was, at the time, being properly operated and maintained (note that an upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation); and
- c. that the permittee has specified and taken action on all responsible steps to minimize or correct any adverse impact in the environment resulting from noncompliance with this permit.

No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

In any enforcement proceedings, the permittee, seeking to establish the occurrence of an upset, has the burden of proof.

#### 9. Bypass Prohibition and Notification

- a. Bypass Prohibition  
Bypass is prohibited, and the Department may take an enforcement action, unless:
  - 1) bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;
  - 2) there were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate backup equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass; and
  - 3) the permittee submitted notices as required under 9.b. or 9.c. below.
- b. Notice of Anticipated Bypass  
If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least ten (10) days before the date of the bypass, and provide information about the anticipated bypass as required by the Department. The Department may approve an anticipated bypass, after considering its adverse effects, if it will meet the three (3) conditions listed in 9.a. above.
- c. Notice of Unanticipated Bypass  
The permittee shall submit notice to the Department of an unanticipated bypass by calling the Department at the number indicated on the second page of this permit (if the notice is provided after regular working hours, use the following number: 1-800-292-4706) as soon as possible, but no later than 24 hours from the time the permittee becomes aware of the circumstances.

## PART II

### Section C. Reporting Requirements

- d. **Written Report of Bypass**  
A written submission shall be provided within five (5) working days of commencing any bypass to the Department, and at additional times as directed by the Department. The written submission shall contain a description of the bypass and its cause; the period of bypass, including exact dates and times, and if the bypass has not been corrected, the anticipated time it is expected to continue; steps taken or planned to reduce, eliminate, and prevent reoccurrence of the bypass; and other information as required by the Department.
- e. **Bypass Not Exceeding Limitations**  
The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to ensure efficient operation. These bypasses are not subject to the provisions of 9.a., 9.b., 9.c., and 9.d., above. This provision does not relieve the permittee of any notification responsibilities under Part II.C.11. of this permit.
- f. **Definitions**
- 1) Bypass means the intentional diversion of waste streams from any portion of a treatment facility.
  - 2) Severe property damage means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

### 10. Bioaccumulative Chemicals of Concern (BCC)

Consistent with the requirements of R 323.1098 and R 323.1215 of the Michigan Administrative Code, the permittee is prohibited from undertaking any action that would result in a lowering of water quality from an increased loading of a BCC unless an increased use request and antidegradation demonstration have been submitted and approved by the Department.

### 11. Notification of Changes in Discharge

The permittee shall notify the Department, in writing, as soon as possible but no later than 10 days of knowing, or having reason to believe, that any activity or change has occurred or will occur which would result in the discharge of: 1) detectable levels of chemicals on the current Michigan Critical Materials Register, priority pollutants or hazardous substances set forth in 40 CFR 122.21, Appendix D, or the Pollutants of Initial Focus in the Great Lakes Water Quality Initiative specified in 40 CFR 132.6, Table 6, which were not acknowledged in the application or listed in the application at less than detectable levels; 2) detectable levels of any other chemical not listed in the application or listed at less than detection, for which the application specifically requested information; or 3) any chemical at levels greater than five times the average level reported in the complete application (see the first page of this permit, for the date(s) the complete application was submitted). Any other monitoring results obtained as a requirement of this permit shall be reported in accordance with the compliance schedules.

## PART II

### Section C. Reporting Requirements

#### 12. Changes in Facility Operations

Any anticipated action or activity, including but not limited to facility expansion, production increases, or process modification, which will result in new or increased loadings of pollutants to the receiving waters must be reported to the Department by a) submission of an increased use request (application) and all information required under R 323.1098 (Antidegradation) of the Water Quality Standards or b) by notice if the following conditions are met: 1) the action or activity will not result in a change in the types of wastewater discharged or result in a greater quantity of wastewater than currently authorized by this permit; 2) the action or activity will not result in violations of the effluent limitations specified in this permit; 3) the action or activity is not prohibited by the requirements of Part II.C.10.; and 4) the action or activity will not require notification pursuant to Part II.C.11. Following such notice, the permit or, if applicable, the facility's COC may be modified according to applicable laws and rules to specify and limit any pollutant not previously limited.

#### 13. Transfer of Ownership or Control

In the event of any change in control or ownership of facilities from which the authorized discharge emanates, the permittee shall submit to the Department 30 days prior to the actual transfer of ownership or control a written agreement between the current permittee and the new permittee containing: 1) the legal name and address of the new owner; 2) a specific date for the effective transfer of permit responsibility, coverage and liability; and 3) a certification of the continuity of or any changes in operations, wastewater discharge, or wastewater treatment.

If the new permittee is proposing changes in operations, wastewater discharge, or wastewater treatment, the Department may propose modification of this permit in accordance with applicable laws and rules.

#### 14. Operations and Maintenance Manual

For wastewater treatment facilities that serve the public (and are thus subject to Part 41 of the NREPA), Section 4104 of Part 41 and associated Rule 2957 of the Michigan Administrative Code allow the Department to require an Operations and Maintenance (O&M) Manual from the facility. An up-to-date copy of the O&M Manual shall be kept at the facility and shall be provided to the Department upon request. The Department may review the O&M Manual in whole or in part at its discretion and require modifications to it if portions are determined to be inadequate.

At a minimum, the O&M Manual shall include the following information: permit standards; descriptions and operation information for all equipment; staffing information; laboratory requirements; record keeping requirements; a maintenance plan for equipment; an emergency operating plan; safety program information; and copies of all pertinent forms, as-built plans, and manufacturer's manuals.

Certification of the existence and accuracy of the O&M Manual shall be submitted to the Department at least sixty days prior to start-up of a new wastewater treatment facility. Recertification shall be submitted sixty days prior to start-up of any substantial improvements or modifications made to an existing wastewater treatment facility.

## PART II

### Section C. Reporting Requirements

#### 15. Signatory Requirements

All applications, reports, or information submitted to the Department in accordance with the conditions of this permit and that require a signature shall be signed and certified as described in the Federal Act and the NREPA.

The Federal Act provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance, shall, upon conviction, be punished by a fine of not more than \$10,000 per violation, or by imprisonment for not more than 6 months per violation, or by both.

The NREPA (Section 3115(2)) provides that a person who at the time of the violation knew or should have known that he or she discharged a substance contrary to this part, or contrary to a permit, COC, or order issued or rule promulgated under this part, or who intentionally makes a false statement, representation, or certification in an application for or form pertaining to a permit or COC or in a notice or report required by the terms and conditions of an issued permit or COC, or who intentionally renders inaccurate a monitoring device or record required to be maintained by the Department, is guilty of a felony and shall be fined not less than \$2,500.00 or more than \$25,000.00 for each violation. The court may impose an additional fine of not more than \$25,000.00 for each day during which the unlawful discharge occurred. If the conviction is for a violation committed after a first conviction of the person under this subsection, the court shall impose a fine of not less than \$25,000.00 per day and not more than \$50,000.00 per day of violation. Upon conviction, in addition to a fine, the court in its discretion may sentence the defendant to imprisonment for not more than 2 years or impose probation upon a person for a violation of this part. With the exception of the issuance of criminal complaints, issuance of warrants, and the holding of an arraignment, the circuit court for the county in which the violation occurred has exclusive jurisdiction. However, the person shall not be subject to the penalties of this subsection if the discharge of the effluent is in conformance with and obedient to a rule, order, permit, or COC of the Department. In addition to a fine, the attorney general may file a civil suit in a court of competent jurisdiction to recover the full value of the injuries done to the natural resources of the state and the costs of surveillance and enforcement by the state resulting from the violation.

#### 16. Electronic Reporting

Upon notice by the Department that electronic reporting tools are available for specific reports or notifications, the permittee shall submit electronically all such reports or notifications as required by this permit.

## PART II

### Section D. Management Responsibilities

#### 1. Duty to Comply

All discharges authorized herein shall be consistent with the terms and conditions of this permit. The discharge of any pollutant identified in this permit, more frequently than, or at a level in excess of, that authorized, shall constitute a violation of the permit.

It is the duty of the permittee to comply with all the terms and conditions of this permit. Any noncompliance with the Effluent Limitations, Special Conditions, or terms of this permit constitutes a violation of the NREPA and/or the Federal Act and constitutes grounds for enforcement action; for permit or Certificate of Coverage (COC) termination, revocation and reissuance, or modification; or denial of an application for permit or COC renewal.

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

#### 2. Operator Certification

The permittee shall have the waste treatment facilities under direct supervision of an operator certified at the appropriate level for the facility certification by the Department, as required by Sections 3110 and 4104 of the NREPA. Permittees authorized to discharge storm water shall have the storm water treatment and/or control measures under direct supervision of a storm water operator certified by the Department, as required by Section 3110 of the NREPA.

#### 3. Facilities Operation

The permittee shall, at all times, properly operate and maintain all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this permit. Proper operation and maintenance includes adequate laboratory controls and appropriate quality assurance procedures.

#### 4. Power Failures

In order to maintain compliance with the effluent limitations of this permit and prevent unauthorized discharges, the permittee shall either:

- a. provide an alternative power source sufficient to operate facilities utilized by the permittee to maintain compliance with the effluent limitations and conditions of this permit; or
- b. upon the reduction, loss, or failure of one or more of the primary sources of power to facilities utilized by the permittee to maintain compliance with the effluent limitations and conditions of this permit, the permittee shall halt, reduce or otherwise control production and/or all discharge in order to maintain compliance with the effluent limitations and conditions of this permit.

#### 5. Adverse Impact

The permittee shall take all reasonable steps to minimize or prevent any adverse impact to the surface waters or groundwaters of the state resulting from noncompliance with any effluent limitation specified in this permit including, but not limited to, such accelerated or additional monitoring as necessary to determine the nature and impact of the discharge in noncompliance.

## PART II

### Section D. Management Responsibilities

#### 6. Containment Facilities

The permittee shall provide facilities for containment of any accidental losses of polluting materials in accordance with the requirements of the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code). For a Publicly Owned Treatment Work (POTW), these facilities shall be approved under Part 41 of the NREPA.

#### 7. Waste Treatment Residues

Residuals (i.e. solids, sludges, biosolids, filter backwash, scrubber water, ash, grit, or other pollutants or wastes) removed from or resulting from treatment or control of wastewaters, including those that are generated during treatment or left over after treatment or control has ceased, shall be disposed of in an environmentally compatible manner and according to applicable laws and rules. These laws may include, but are not limited to, the NREPA, Part 31 for protection of water resources, Part 55 for air pollution control, Part 111 for hazardous waste management, Part 115 for solid waste management, Part 121 for liquid industrial wastes, Part 301 for protection of inland lakes and streams, and Part 303 for wetlands protection. Such disposal shall not result in any unlawful pollution of the air, surface waters or groundwaters of the state.

#### 8. Right of Entry

The permittee shall allow the Department, any agent appointed by the Department, or the Regional Administrator, upon the presentation of credentials and, for animal feeding operation facilities, following appropriate biosecurity protocols:

- a. to enter upon the permittee's premises where an effluent source is located or any place in which records are required to be kept under the terms and conditions of this permit; and
- b. at reasonable times to have access to and copy any records required to be kept under the terms and conditions of this permit; to inspect process facilities, treatment works, monitoring methods and equipment regulated or required under this permit; and to sample any discharge of pollutants.

#### 9. Availability of Reports

Except for data determined to be confidential under Section 308 of the Federal Act and Rule 2128 (R 323.2128 of the Michigan Administrative Code), all reports prepared in accordance with the terms of this permit, shall be available for public inspection at the offices of the Department and the Regional Administrator. As required by the Federal Act, effluent data shall not be considered confidential. Knowingly making any false statement on any such report may result in the imposition of criminal penalties as provided for in Section 309 of the Federal Act and Sections 3112, 3115, 4106 and 4110 of the NREPA.

#### 10. Duty to Provide Information

The permittee shall furnish to the Department, within a reasonable time, any information which the Department may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or the facility's COC, or to determine compliance with this permit. The permittee shall also furnish to the Department, upon request, copies of records required to be kept by this permit.

Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the Department, it shall promptly submit such facts or information.

## PART II

### Section E. Activities Not Authorized by This Permit

#### 1. Discharge to the Groundwaters

This permit does not authorize any discharge to the groundwaters. Such discharge may be authorized by a groundwater discharge permit issued pursuant to the NREPA.

#### 2. POTW Construction

This permit does not authorize or approve the construction or modification of any physical structures or facilities at a POTW. Approval for the construction or modification of any physical structures or facilities at a POTW shall be by permit issued under Part 41 of the NREPA.

#### 3. Civil and Criminal Liability

Except as provided in permit conditions on "Bypass" (Part II.C.9. pursuant to 40 CFR 122.41(m)), nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance, whether or not such noncompliance is due to factors beyond the permittee's control, such as accidents, equipment breakdowns, or labor disputes.

#### 4. Oil and Hazardous Substance Liability

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee may be subject under Section 311 of the Federal Act except as are exempted by federal regulations.

#### 5. State Laws

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable state law or regulation under authority preserved by Section 510 of the Federal Act.

#### 6. Property Rights

The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize violation of any federal, state or local laws or regulations, nor does it obviate the necessity of obtaining such permits, including any other Department of Environment, Great Lakes, and Energy permits, or approvals from other units of government as may be required by law.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) )  
Emergency Order: Midcontinent )  
Independent System Operator )  
(MISO) )  
\_\_\_\_\_ )

Order No. 202-26-16

Exhibit to  
Motion to Intervene and Request for Rehearing and Stay of  
Public Interest Organizations

Exhibit 49  
2025 Energy Innovation  
Dataset



State	Increase in Coal Power Cost By State (\$/MWh)	Weighted Avg Cost of Coal Power by State in 2024 (\$/MWh)
AL	37.93393999	7.480297212
AR	41.90122231	5.944721732
AZ	56.51554642	14.08344442
CA		
CO	39.33535838	10.30820944
CT		
DC		
DE	221.8761029	127.3387759
FL	53.50549995	5.689998956
GA	66.71100175	19.00841935
IA	38.63343192	9.725805912
ID		
IL	38.81721467	7.571739858
IN	58.81188822	14.90842856
KS	42.54800667	9.509355837
KY	46.35093349	9.308201802
LA	63.2739221	18.79729695
MA		
MD	73.70844799	17.10580366
ME		
MI	45.07020455	10.30771609
MN	41.18833898	5.034647863
MO	34.34030065	5.707797427
MS	60.76349909	15.46149471
MT	41.0604362	7.122524784
NC	68.01818431	19.01343787
ND	34.53581284	6.265181942
NE	27.86386333	4.19594737
NH	202.3922844	94.96768747
NJ		
NM	61.31310294	8.548435411
NV	79.4294835	28.32650169
NY		
OH	48.82266897	13.98484121
OK	53.95115581	16.43031007
OR		
PA	60.74068094	17.62564958
RI		
SC	54.28073668	7.077291056
SD	46.0068521	9.695183185
TN	53.30676073	12.71282206
TX	39.11171011	6.261700769
UT	58.53091529	23.6707588

VA	89.18327645	31.34968258
VT		
WA	46.8715898	8.836472222
WI	40.58935338	5.864332044
WV	50.24364994	14.67356958
WY	33.81029024	4.901115837

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) )  
Emergency Order: Midcontinent )  
Independent System Operator )  
(MISO) )  
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Exhibit to  
Motion to Intervene and Request for Rehearing and Stay of  
Public Interest Organizations

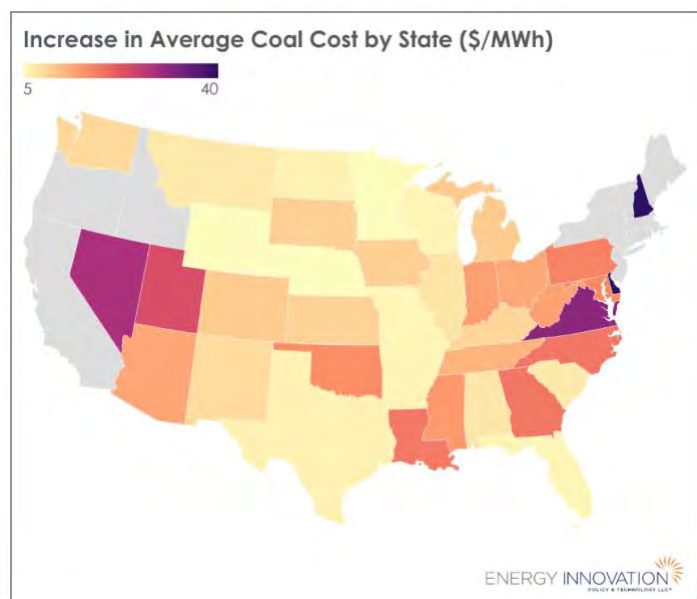
Exhibit 50  
2025 Energy Innovation  
Coal Cost Report

# COAL POWER 28 PERCENT MORE EXPENSIVE IN 2024 THAN IN 2021

Since 2021, the cost to generate coal power in the United States has increased faster than inflation, on average, meaning that coal is putting further inflationary pressure on American electricity consumers. This updated analysis on coal costs shows that in 2024, coal power was 28 percent more expensive than in 2021, costing consumers \$6.2 billion more to generate power via coal than it would have cost in 2021.

Coal power is declining across the United States, largely because of these poor economics. Total coal power use peaked in 2007 and has fallen ever since, generating barely 15 percent at the beginning of 2025. Between 2021 and the beginning of 2025, nearly 50 plants retired or are no longer burning coal, and over a third of the remaining fleet is expected to retire by 2030.<sup>1</sup>

This reality sits in stark contrast to U.S. federal power policy. The Trump administration issued a series of executive orders in April 2025 aiming to keep coal plants running despite their impact on electricity consumers. These include orders to reduce the number of plants subject to the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards,<sup>2</sup> and to keep uneconomic plants running long-term using short-term emergency powers.<sup>3</sup> This has already resulted in a plant ordered to remain open – the J.H Campbell plant owned by Consumers Energy in Michigan which was scheduled to close May 31.<sup>4</sup>

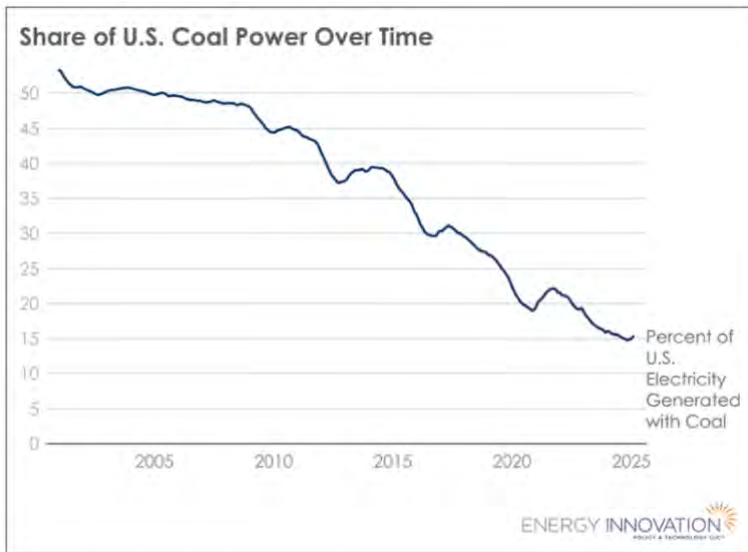


<sup>1</sup> <https://ieefa.org/resources/nowhere-go-down-us-coal-capacity-generation>

<sup>2</sup> [https://www.whitehouse.gov/presidential-actions/2025/04/rregulatory-relief-for-certain-stationary-sources-to-promote-american-energy/?utm\\_source=chatgpt.com](https://www.whitehouse.gov/presidential-actions/2025/04/rregulatory-relief-for-certain-stationary-sources-to-promote-american-energy/?utm_source=chatgpt.com)

<sup>3</sup> <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>

<sup>4</sup> <https://apnews.com/article/michigan-power-plant-coal-trump-aa6244ce5e7cca4326e582c849e0bc98>



Source: U.S. Energy Information Administration

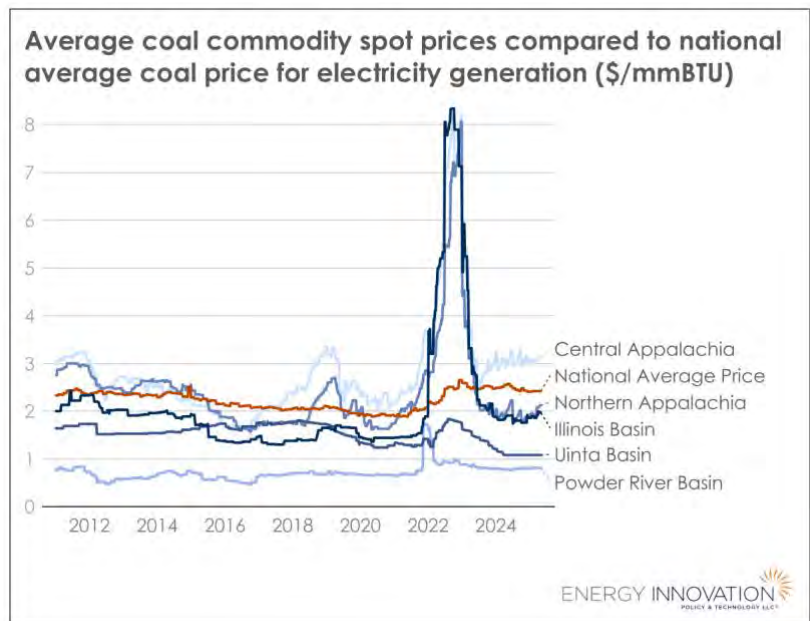
But these orders ignore the economic fundamentals underpinning coal's decline: wind, solar, batteries, natural gas, and efficiency are simply cheaper than coal power. Previous Energy Innovation research showed that 99 percent of coal plants were more expensive to continue operating compared to replacement with local wind or solar.<sup>5</sup> Attempts to keep coal running beyond plants' economic lifetime will force Americans to pay higher electricity bills.

As the new analysis detailed here shows, coal plants have only gotten more expensive since our last analysis based on the 2021 coal fleet, which largely followed the trends of the overall cost of coal for fuel.

Prices spiked in 2022, after Russia invaded Ukraine. This event increased all fossil fuel prices. While coal fuel prices fell after 2022, they remained elevated over 2021 levels in most regions of the country, and the national average price of coal delivered to the electricity sector remained elevated, too.

These higher prices are seen most acutely in the Appalachian coal producing regions, where coal has been more expensive for years due to the depth of coal within the mines, a problem that only becomes more acute with more mining.<sup>6</sup>

Our updated analysis uses the same methodology as detailed in the Coal Cost Crossover 3.0 for calculation of coal costs,<sup>7</sup> and shows coal's economic decline has continued.



Source: U.S. Energy Information Administration

<sup>5</sup> <https://energyinnovation.org/report/the-coal-cost-crossover-3-0/>

<sup>6</sup> <https://www.eia.gov/energyexplained/coal/prices-and-outlook.php>

<sup>7</sup> This methodology does not account for any increases in cost due to very large capital expenditures such as those required to comply with air pollutant regulations. Any pollution upgrades would significantly increase the costs of plants beyond what is calculated here.

## KEY FINDINGS

Power generated by coal in 2024 was 28 percent more expensive on average than in 2021

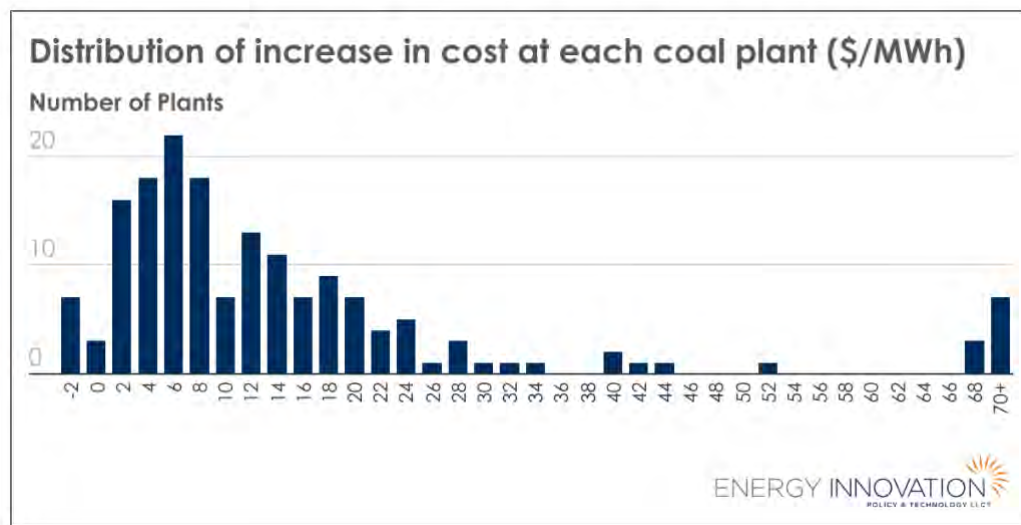
In 2021, the weighted average cost of a megawatt-hour (MWh) of power generated by coal-fired power plants was \$36/MWh, while in 2024, this number rose to \$46/MWh, or a 28 percent increase across the U.S. coal fleet. The Consumer Price Index, a proxy for inflation, increased by 16 percent from 2021 to 2024,<sup>8</sup> which means the cost of power generated by coal grew significantly faster than inflation.

Factors contributing to this increase include a rise in the cost of fuel for plants, as well as increased operations and maintenance costs and capital costs due to aging plants and inflation. Plants also ran less on average, which drives up their cost in dollars per MWh, with our analysis showing that the average coal plant capacity factors dropped to 38 percent in 2024 from 46 percent in 2021.

With 622 million megawatt hours of power generated by coal in 2024, this means coal plant owners spent over \$6.2 billion more than they would have spent for that same amount of electricity generated by coal in 2021, costs that are directly passed onto consumers through electricity rates.

95 percent of remaining coal plants generated power at a higher cost than they did in 2021

We analyzed 162 plants, consisting of 181 GW of capacity, that were still operating at the beginning of 2025. Almost every plant saw costs increase but increases ranged widely between plants. 95 percent of plants were more expensive, and 76 percent of plants (142 GW) saw costs rise faster than inflation since 2021. Nearly half of these saw cost increases double the rate of inflation over this period.

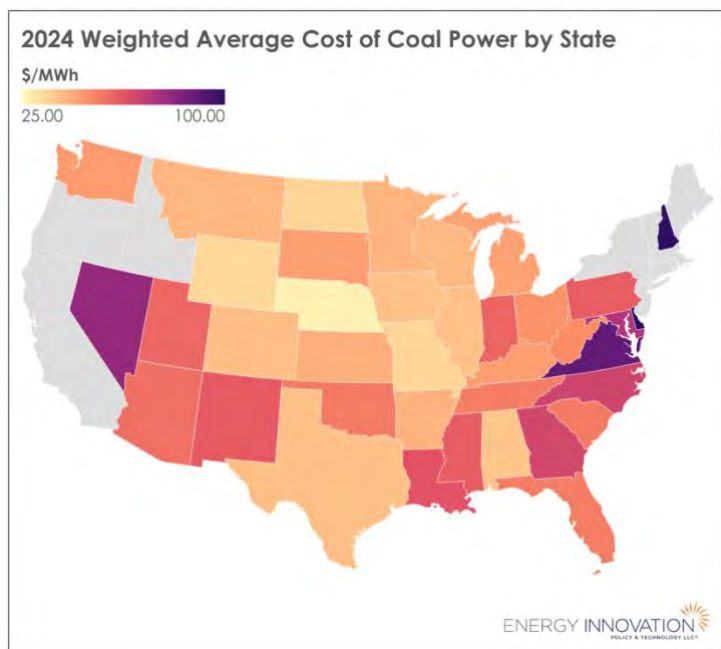


<sup>8</sup> <https://www.minneapolisfed.org/about-us/monetary-policy/inflation-calculator/consumer-price-index-1913->

## The cost of coal was highest in the Mid-Atlantic, Southeast, and Southwest

Delaware and New Hampshire saw the highest coal costs on average in 2024. Each state has only one plant still in operation, and plans to shut these plants down are imminent, with Delaware's scheduled for retirement in 2026 and New Hampshire's in 2028. Outside of these two, the states with the highest coal cost were Georgia, Louisiana, Maryland, Mississippi, Nevada, New Mexico, North Carolina, and Virginia.

Many of the most expensive coal-burning states source coal from the most expensive mines, with states east of the Mississippi generally seeing more expensive average costs than those in the West.



Despite these high costs, states like Georgia and South Carolina have extended the lives of several plants, including Plant Bowen and Williams. Plant Bowen was originally scheduled for retirement in 2028, but Georgia Power has recently extended its life to 2035.<sup>9</sup> Its costs increased by \$26/MWh, from \$46/MWh to \$72/MWh. Williams, a 659 MW plant in South Carolina has had its retirement pushed from 2028 to 2031 or even later in Dominion Energy's recent integrated resource plan. This delay comes even as this analysis shows the plant has increased in cost by \$27/MWh, or over 50 percent.<sup>10</sup>

States in the West were not insulated from cost increases. Cost increases in Utah were particularly high, largely due to the Hunter and Huntington plants, which were previously scheduled for retirement in 2032, but instead are now planned to stay online indefinitely. The cost increase is largely due to issues with the mine that supplies coal to these plants, the Lila Coal Mine, which caught on fire in 2022, was declared "idled indefinitely" at the end of 2023 and all 150 workers laid off.<sup>11</sup> Costs to run these two plants nearly doubled from around \$30/MWh to over \$60/MWh. Even plants that have functioning dedicated mines in the cheapest coal region of the country, the Powder River Basin, have still seen significant increases in coal costs.

<sup>9</sup><https://georgiarecorder.com/briefs/two-georgia-power-coal-plants-among-the-dozens-now-exempt-from-biden-era-pollution-rule/>

<sup>10</sup><https://www.wfyi.org/news/articles/duke-energy-plans-to-delay-gibson-coal-plant-retirement-activists-say-its-a-step-backward>

<sup>11</sup><https://www.sierraclub.org/press-releases/2025/04/dominion-energy-keeps-south-carolina-s-coal-plants-operating-2025-irp-update#:~:text=Dominion%20has%20already%20pushed%20back,potentially%20as%20late%20as%202034.>

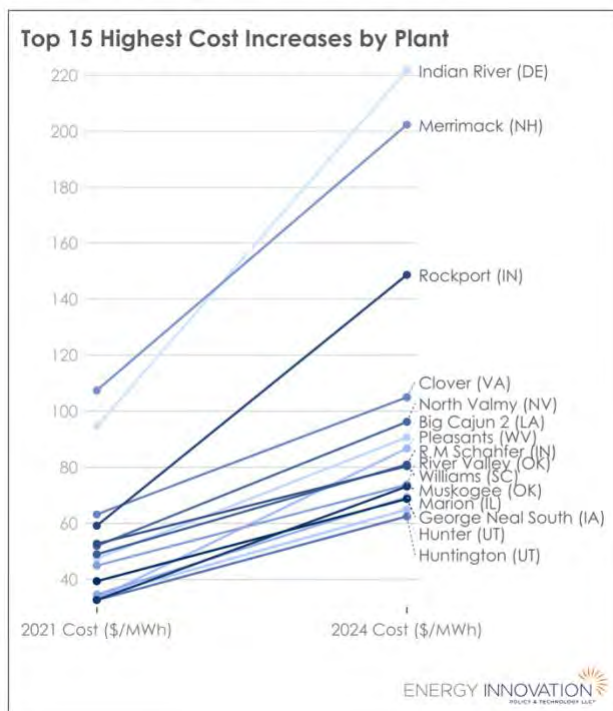
## ACTIONS TO PROTECT CONSUMERS FROM RISING COSTS

Because the cost of coal power is increasing faster than inflation, the Trump administration's executive orders and attempts to keep coal-fired power plants running will increase the cost of electricity.

Coal-fired power increases its cost burden on customers year after year, and the period from 2021 to 2024 was no different. With costs increasing across America's entire fleet, states that continue to rely on coal, like Kentucky and West Virginia, have unsurprisingly suffered electric rates climbing faster than even those coal-heavy states that have begun to incorporate renewable power.<sup>12</sup> Even as this coal reliance has harmed electricity customers and neighboring states have declined cost recovery for upgrades, regulators in West Virginia have required plants to stay online. Meanwhile, residential electricity rates in West Virginia have risen 24 percent since 2021.

While keeping coal power online longer to meet growing load may seem like an attractive option, continuing to rely on these aging plants with high fuel costs will likely continue harming those captive customers whose policymakers force expensive plants to stay online, even as cheaper options are available. Strategies like moving new generation and battery storage through interconnection queues more quickly,<sup>13</sup> getting more out of the grid by upgrading transmission lines<sup>14</sup> and utilizing surplus interconnection capacity,<sup>15</sup> and deploying demand response and efficiency<sup>16</sup> can help ensure America has the capacity needed to meet growing load while protecting consumers from paying the price to subsidize uneconomic coal.

Comprehensive planning and competitive procurement are also essential to ensuring that electricity customers pay the cheapest price for power. Using best practices in integrated resource planning will make sure that least-cost resource portfolios are selected. These include inclusive stakeholder processes with technical experts participating, developing model inputs and cost estimates that align with real-world data and high quality forecasts, and analyzing multiple scenarios and sensitivities.<sup>17</sup>



<sup>12</sup><https://kentucky Lantern.com/2025/04/10/heavy-reliance-on-coal-has-eroded-a-ky-economic-advantage-can-trump-reverse-the-trend/>

<sup>13</sup><https://collaborative.evergreenaction.com/memos/approving-clean-energy-projects-faster-could-save-consumers-505-a-year-in-these-13-states-16>

<sup>14</sup> <https://www.2035report.com/reconducting/>

<sup>15</sup> <https://www.utilitydive.com/news/surplus-interconnection-gridlab-berkeley-report/740262/>

<sup>16</sup> <https://energyinnovation.org/wp-content/uploads/2024/03/MEETING-GROWING-ELECTRICITY-DEMAND-WITHOUT-GAS.pdf>

<sup>17</sup> <https://emp.lbl.gov/publications/best-practices-integrated-resource>

Beyond good planning, all-source competitive procurement, or the process by which all technologies are fairly considered to meet grid needs, can make sure that the cheapest plans turn into the cheapest projects built.<sup>18</sup>

Common-sense policies can also help reduce the impact of expensive coal plants on consumers. For instance, in many states, coal plants are permitted to run even when they are not the cheapest resource to meet the need. This is called “uneconomic dispatch,” costs consumers over \$2 billion annually, and is most prevalent in the Southeast and West where the lack of regional transmission operator reduces pricing transparency. Where full electricity markets are not implemented, moving towards day ahead or real time energy markets that are coordinated by a centralized entity is key to ensuring consumers pay a fair price, and utility regulators can push for better operational practices to save customers money.<sup>19</sup>

Electricity planners have options to keep the lights on, but electricity consumers generally have little to no choice in the price they pay for power. As costs continue to rise, now is not the time to double down on coal. It is up to the regulators and policymakers overseeing the coal fleet to protect consumers, and find cheaper, cleaner options to help Americans thrive.

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<sup>18</sup><https://energyinnovation.org/report/making-the-most-of-the-power-plant-market-best-practices-for-all-source-procurement-of-electric-generation/>

<sup>19</sup> <https://rmi.org/how-utilities-can-save-customers-billions-of-dollars/>

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) )  
Emergency Order: Midcontinent )  
Independent System Operator )  
(MISO) )  
\_\_\_\_\_ )

Order No. 202-26-16

Exhibit to  
Motion to Intervene and Request for Rehearing and Stay of  
Public Interest Organizations

Exhibit 51  
2023 Energy Innovation  
Coal Cost Report

# Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment

MICHELLE SOLOMON, ERIC GIMON, MIKE O'BOYLE  
(ENERGY INNOVATION®), UMED PALIWAL, AND AMOL  
PHADKE (UNIVERSITY OF CALIFORNIA, BERKELEY)

JANUARY 2023

## EXECUTIVE SUMMARY

The cost of operating existing coal power plants in the United States continues to increase while coal jobs, generation, and mining all decrease.<sup>i</sup> New coal retirement announcements seem to happen faster, even as natural gas prices skyrocket, and renewable energy prices keep dropping.

The Inflation Reduction Act (IRA), which extended and expanded clean energy tax credits, along with new funding to guarantee loans for refinancing fossil assets and reinvesting in clean energy infrastructure, has shifted the economic scale even further toward wind and solar. But it also creates thoughtful new investment opportunities in areas burdened by existing coal plants with a 10 percent tax credit boost for projects located in nearby communities.

These factors underpin the third iteration of our Coal Cost Crossover analysis, which shows wind and solar energy are unequivocally cheaper than coal-fired generation across the country. This study finds 99 percent of all coal-fired power plants in the U.S. are more expensive to operate on a forward-

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<sup>i</sup> This research is accessible under the [CC BY](#) license. Users are free to copy, distribute, transform, and build upon the material as long as they credit Energy Innovation Policy & Technology LLC® for the original creation and indicate if changes were made.

looking basis than the all-in cost of replacement renewable energy projects, and 97 percent are more expensive than renewable energy projects sited within 45 kilometers (approximately 30 miles), a significant acceleration from our two previous analyses. For more than three quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace.

In this report we compare the cost of operating each continental U.S. coal plant in 2021, totaling 220 gigawatts (GW) of coal capacity across the country, to the estimated costs of building new wind and solar generation. We consider the wind and solar costs within two geographic scopes: local to the coal plants (within 45 kilometers) and regionally (roughly within the utility balancing area), finding that nearly all existing coal plants have multiple lower-cost clean energy replacement options.

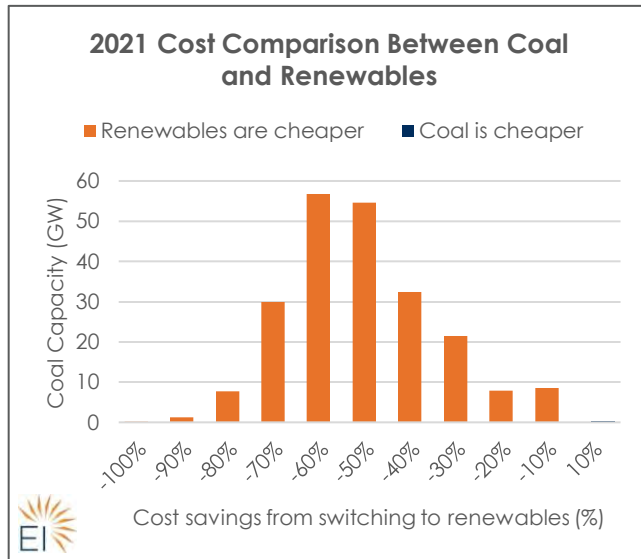
This research shows all but one of the country's 210 coal plants are more expensive to operate than either new wind or new solar. If the IRA's new energy community tax credit is included in the equation, 199 of the 210 plants are more expensive to operate compared to local solar resources sited within 45 kilometers of the plant. Local wind resources are also cost-effective and readily available, with 104 plants having cheaper wind resources within 45 kilometers.

Altogether, 205 plants have local renewable options that would be cheaper than coal-fired electricity. This potential to replace existing coal plants with cheap, local clean energy generation creates significant economic benefits for community transition. Our analysis finds replacing these plants with local solar or wind would drive \$589 billion in local capital investment that could support economic diversification, job creation, and tax revenue.

These local wind and solar resources could also help solve the problem of long interconnection queues—a significant barrier to renewables deployment. Renewable projects built near a retiring coal plant could use the existing plant's interconnection, helping to further lower costs. If more policymakers consider this dynamic, they can streamline economic replacement and anticipate coal retirements, which are accelerating due to the cost dynamics analyzed in this report.

While solar and wind replacement resources provide significant low-cost energy and reliability value to the grid, savings generated by switching from more expensive coal to cheaper clean energy can finance other resources to provide additional energy and reliability value.

We find that the savings generated by shifting to local solar could fund the addition of 137 GW of four-hour batteries across all plants, and 80 percent or more of the capacity at a third of existing coal plants—the economics of replacing coal with renewables are so favorable that they could fund a massive battery storage buildout to add reliability value along with emissions reductions. However, it is important to remember reliability is a system attribute—replacement renewable



portfolios need not bear sole responsibility for replacing the reliability services of individual coal plants.

While the economic case is clear and virtually universal, barriers remain to replacing coal with clean energy, and policymakers must act to unlock the cost savings and human health benefits for coal communities while reducing climate pollution.

Several policies can enable a faster coal-to-clean transition. Specifically:

- **To prepare the way for coal transition, regulators and system operators should:**
  - Improve methods to assess reliability and resource adequacy reflecting the reliability value of renewable portfolios and valuing the reliability attributes of a high-renewables grid.
  - Update interconnection study rules to leveraging existing coal plant interconnection rights to speed grid connection processes for local renewable replacement resources.
- **To proactively pursue the transition, regulators should:**
  - Encourage utilities to utilize IRA financing programs available through the Departments of Energy and Agriculture to remove financial barriers to coal community economic transition and investment.
  - Enable competitive resource procurement.
  - Require re-assessment of any utility investment plan, including integrated resource plans and market-based solicitations for renewable supply, completed prior to IRA as renewables costs are now out of date.
- **To create a just transition for affected communities, state legislatures and energy offices should:**
  - Plan for and fund a coal community-centered economic transition, where local clean energy resources are the anchor for a more expansive economic transition plan.

## ACKNOWLEDGEMENTS

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## INTRODUCTION

The U.S. power sector is in transition, with coal-fired power generation falling to 55 percent of its 2007 peak in 2021. This transition is also decreasing the number of coal mines, power plants, and workers. Over the same period, utility-scale solar and wind generation have increased more than

18,000 percent and 1,000 percent, respectively, as costs declined by 90 percent for solar and 72 percent for wind.<sup>1,ii</sup>

In 2019, Energy Innovation Policy & Technology LLC® partnered with Vibrant Clean Energy to compile and analyze a 2018 dataset of capital, operations and maintenance, and fuel costs for coal, wind, and solar. Our first Coal Cost Crossover report found that 62 percent of existing coal capacity was uneconomic compared to producing the same amount of energy with new local wind or solar. To make this comparison, we evaluated the marginal cost of running each coal plant with the levelized cost of new wind and solar, where the levelized cost of energy (LCOE) is the cost of building and operating a new resource divided by its energy production over its lifetime. The analysis projected that by 2025, more than 80 percent of the coal fleet would be unable to compete against new renewables or would be retired, even without federal incentives.<sup>2</sup>

In 2021, we completed a similar analysis of 2019 data that considered the National Renewable Energy Laboratory's (NREL) 2018 Annual Technology Baseline (ATB) forecast showing steep cost declines for solar and wind energy, as well as an extension of the federal investment tax credit for solar coupled with a continued production tax credit for wind. The Coal Cost Crossover 2.0 report found that the coal crossover had significantly expanded, with 72 percent of coal capacity and 80 percent of plants already more expensive to run compared to either new solar or wind, including tax credits in effect.<sup>3</sup>

This Coal Cost Crossover 3.0 report uses new 2021 data to reevaluate the coal crossover economic dynamic. Since our 2.0 report, solar and wind costs continued fall, coal prices kept rising, and coal plant capacity factors continued decreasing, all continuing the trends observed between 2017-2019.<sup>iii</sup>

Now, new federal tax credits in the IRA make the economic case for replacing coal with clean energy unequivocal. IRA incentive bonuses for clean energy projects located near retired coal infrastructure offer new, additional savings and reinvestment opportunities. This report combines elements of the previous two studies, analyzing both regional and local renewable resources, but now accounts for the new incentives.<sup>4</sup> Given the IRA's expanded tax credits, we find all coal plants but one are more costly to run compared to new wind and solar energy, and all but five are more expensive than wind or solar sited within a 45 kilometer (km) radius.

Of course, examining relative economics using levelized cost faces limitations. The overall value of these power plants depends on much more than just cost. While the coal cost crossover describes a scenario in which renewable resources replace coal generation on a one-to-one basis, the reality is that coal retirement is a complex process that depends on the reliability needs of the local and

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<sup>ii</sup> Coal generation decreased from 2,016,455 gigawatt-hours (GWh) in 2007 to 875,885 GWh in 2021. Solar generation increased from only 612 GWh in 2007 to 115,258 GWh in 2021. Wind generation increased from 34,449 GWh in 2007 to 378,196 GWh in 2021. In total, coal generation was still higher in 2021 than wind and solar in the U.S. by 382 GWh.

<sup>iii</sup> Renewable costs continued to fall through 2021, the year we used for this analysis. Costs across the energy industry rose in 2022 due to supply chain constraints but are expected to fall again as supply issues ease.

regional electricity grid, which in turn, depends on the entire resource portfolio's dynamics. For example, in some regions one-to-one replacement with a combination of wind and solar resources may not adversely affect reliability. In others it may, depending on what other resources are serving the power grid.

Many communities also depend on coal plants for jobs and tax revenue. In addition to reliability value, policymakers must consider the potential of replacement energy resources to provide similar economic value. The new IRA incentives to locate replacement resources in the same communities where coal plants sit can contribute to a sustainable, economic transition. As we show in this report, these incentives fundamentally improve the prospect for coal communities to benefit from new clean energy resource development.

This report traces the shifting role of coal in the U.S. power sector and identifies key changes in the economics of coal-fired electricity generation due to the IRA's passage. We explain our coal cost crossover calculations, including how we compiled the coal dataset using publicly available data, and how we calculated the LCOE for both local and regional wind and solar using open-source modeling tools developed by NREL.

**Four scenarios** compare new renewable generation costs to marginal coal costs: regional wind, regional solar, local wind, and local solar, effectively assessing the replacement of every unit of energy produced by the coal plants. For the local solar scenario, we also analyze the economics of adding four hours of battery storage capacity to the solar resources. This analysis demonstrates a clean alternative to coal generation with added reliability value and an opportunity for local investment and economic diversification.

Finally, we provide policy recommendations to help policymakers successfully transition away from polluting, higher cost coal power to cheaper, clean energy. Because the IRA aligns the aims of least-cost electricity planning and procurement with an economic transition for coal communities, we highlight the opportunity for gradual economic transition centered around replacing coal generation with local renewables and storage. Local replacement also has the advantage of potentially being able to leverage existing grid interconnection rights. We describe how utilities can directly take advantage of key IRA provisions, as well as how policymakers can ensure utilities account for the changing economic landscape in their planning and procurement. We also explain how just transition planning, accurate reliability assessments, and transmission buildout can speed up and smooth out coal's phaseout in the U.S.

## COAL'S ROLE IN THE U.S. POWER SECTOR

Coal-fired power was the bedrock of a reliable, affordable U.S. power sector for nearly a century. But since 2010, coal generation has declined 52 percent, and renewable power generation exceeded coal generation for the first time in 2020. In 2011, the U.S. had 317.6 GW of coal-fired

electricity generation capacity,<sup>5</sup> but that number fell to 221 GW in 2021. Nearly a quarter of the remaining fleet is slated for retirement by 2029.<sup>6</sup>

Several factors explain this decline, including pollution control standards requiring costly retrofits, cheap natural gas and renewable power, state clean energy policies, and improved building and industrial efficiency.<sup>7</sup> Coal's decline has been accompanied by a precipitous fall in coal industry employment.<sup>8</sup> But even as employment fell, reduced pollution from coal plants dramatically improved public health. Annual deaths attributed to air pollution from coal plants fell from 30,000 deaths in 2000 to less than 3,000 in 2019.<sup>9</sup>

Coal's role in electricity system reliability has shrunk considerably. Coal-fired power plants operate as part of an integrated power system where supply and demand must remain in constant balance. The decline in coal-fired generation and capacity, and replacement by a more diverse portfolio of gas and renewable power plants with vastly different operational characteristics indicates that coal is not necessary for reliable power systems. For example, the United Kingdom reliably operated its grid without any coal generation for two straight months in 2020.<sup>10</sup>

The role of coal plants and their operation in the electricity system has also changed over time. Historically, coal plants operated as “baseload” power plants, relying on a relatively low-cost fuel supply to run at a constant, high output. But now markets are pushing coal plants to operate more variably, ramping up and down as the economics and availability of renewable energy fluctuate throughout the day and over a season.<sup>11</sup> Coal plants in our dataset had an average capacity factor of 46 percent, which means they ran, on average, only 46 percent of the time. This on-again, off-again operation increases wear and tear on coal plants designed for a different operating paradigm.

Displacement by cheaper gas and renewables means baseload operation is increasingly unprofitable for existing coal—operating at high output when plentiful clean energy resources operate at zero marginal cost is a waste of fuel. According to RMI, since 2012 utilities could have saved customers \$1–\$2 billion per year by turning down coal and relying on lower-cost, less polluting resources. This is partially due to self-scheduling, a practice through which monopoly utilities uneconomically run their coal plants in wholesale markets and charge captive customers the difference.<sup>12</sup>

Replacing coal with clean energy is not a one-to-one exercise. System operators and utilities only gain confidence that coal retirements won't adversely affect system reliability by evaluating the reliability of the entire energy portfolio. A recent North American Electric Reliability Corporation (NERC) assessment highlighted the need to build new generation before retiring old generation when reliability risks are present.<sup>13</sup> But recent studies such as the 2030 Report, which found an 80 percent clean, coal-free electricity system to be both reliable and affordable, confirm we can maintain a dependable electricity system without coal.<sup>14</sup>

The U.S. will continue relying on coal plants for reliability until we add enough new clean resources (including demand-side resources and transmission) to replace their reliability and energy services.

The Coal Cost Crossover 3.0 analysis highlights opportunities to economically displace coal-fired generation and replace those services in part. With the IRA's passage, the economic case for shifting from coal to renewables is stronger than ever.

## INFLATION REDUCTION ACT IMPACTS ON U.S. ENERGY ECONOMICS

The IRA will significantly affect the relative economics of coal and clean power in the U.S. In this analysis, the IRA's extended and improved tax credits, along with a pair of refinancing programs, have the greatest effect on the cost of coal compared to renewables.

### Tax Credits

Clean energy tax credits have arguably been the most important federal climate policies to date, driving nationwide solar and wind growth. The IRA builds upon this successful policy to make the clean energy transition cost effective for the long term, with earlier Energy Innovation® analysis finding the credits to be the most impactful IRA provision for electricity sector decarbonization.<sup>15</sup>

The production tax credit (PTC) and investment tax credit (ITC) are the IRA's two key tax credits for new clean electricity resources. Historically, the PTC has primarily supported wind energy resources, and at its full value paid approximately \$26 per megawatt-hour (MWh) in 2022 dollars over the first 10 years of a wind project's commercial operations.<sup>16</sup> The ITC has largely supported solar resources, and at its full value offered a tax credit for 30 percent of total system cost, paid out when it is first placed in service. Prior to the IRA's passage, the PTC had expired, and the ITC had begun phasing out with a value of 26 percent for projects starting construction in 2022.<sup>17</sup> The IRA created long-term certainty for these tax credits, with the extension lasting through 2032 or until electricity sector greenhouse gas (GHG) emissions fall 75 percent below 2022 levels, whichever is later.

The IRA also immediately revived a long-expired option for solar projects placed in service in 2022 or later to elect the PTC instead of the ITC, which ensures that tax credits will stay impactful as solar capital costs continue to fall. In addition, the IRA provides an ITC for stand-alone energy storage technologies placed in service in 2022 or later, removing prior restrictions that required storage to be co-located with and charged primarily from solar energy resources.

Beyond the extension and increased flexibility, the IRA created several human impact bonuses that increase the value of the tax credit. To qualify for the full credit, a project must meet prevailing wage and apprenticeship requirements. Additionally, a project can earn a 10 percent boost for meeting domestic content requirements and an additional 10 percent for locating the project in an energy community (which includes census tracts in which coal-fired power plants have been retired since 2009 and adjacent census tracts, as defined by the IRA, see Figure 1).<sup>iv</sup>

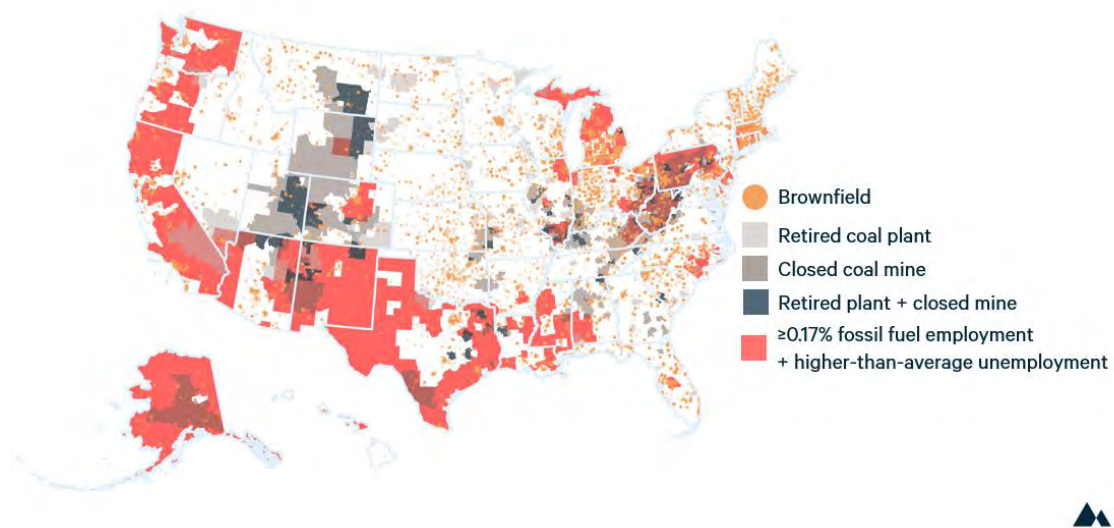


Figure 1. Map of probable energy communities, as defined by the IRA. Source: Resources for the Future.<sup>18</sup>

The combined impacts of energy community, labor, and domestic content bonuses reshape solar economics in coal communities. The median cost of new solar in these communities is about \$24/MWh with low variance, while the median marginal cost of coal is \$36/MWh with higher variance (see Figure 2). As discussed later in this report, this cost differential provides significant headroom for additional battery storage, which can also qualify for energy community bonuses.

<sup>iv</sup> The 10 percent credit boost for siting projects in energy communities works slightly differently for the ITC and PTC, providing a 10-percentage point ITC bonus and a 10 percent bonus on the PTC credit value.

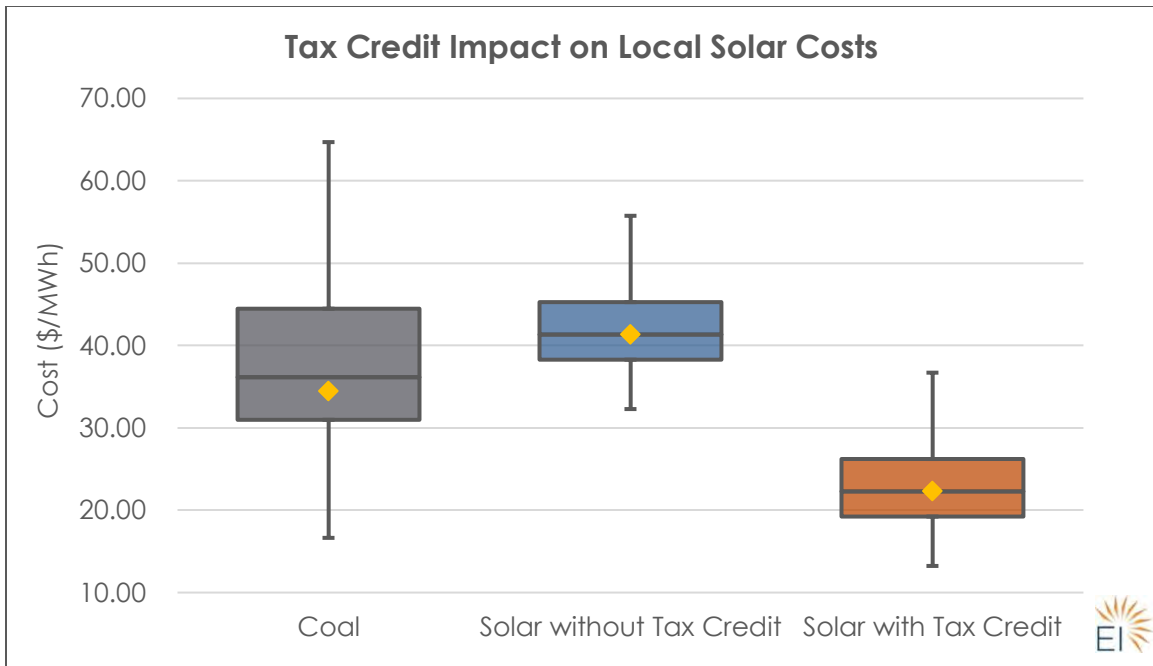


Figure 2. Impact of tax credits on local solar LCOEs in our analysis, including the energy community bonus. The yellow diamond indicates the average cost of each resource (weighted by generation). With the IRA, the economic case for local solar becomes unequivocal.

### Reinvestment Financing

The PTC and ITC play the crucial role of decreasing the cost of developing clean electricity resources, but upfront cost is far from the only barrier to moving from coal generation to clean alternatives. One of the biggest hurdles to this transition is the rate impacts of adding large capital investments to utility rates when billions are still owed to debtors and investors on uneconomic coal assets. But a new IRA financing program to invest in clean energy infrastructure in current or former coal communities can overcome this hurdle. As the program only lasts until 2026, time is of the essence.

Most U.S. coal capacity is owned and operated by monopoly utilities, which collectively hold at least \$176 billion in unpaid fossil plant balances<sup>v</sup>—accounting ledgers that represent the debt and equity capital structures utilities used to finance these plants over time. Utilities include this capital cost in electricity rates, typically recovered over the plant’s entire lifetime in a financial arrangement somewhat similar to a conventional 30-year mortgage (albeit one that is continuously extended as new capital is invested at coal plants). As long as the plant remains in operation or

until the investment is fully depreciated, customers are generally obligated to continue to cover these costs, which include substantial returns for utility shareholders. Without a change to this structure, monopoly utilities have little to gain from early coal plant retirement and they may perceive retirement or partial replacement as putting cost recovery at risk.

New IRA programs provide flexible, low-cost financing to clean up utility balance sheets by reducing the cost of investing in new local clean energy infrastructure, including wind, solar, batteries, transmission infrastructure, and reuse of the coal plant itself. Utilities and other power plant operators, such as independent power producers, can access low-cost government-backed loans to reduce the rate impacts associated with large capital expenditures required to transition from coal to clean and stimulate local economic development. The IRA created two novel programs to support utilities in transition:

First, the IRA appropriated \$5 billion to the U.S. Department of Energy's (DOE) Loan Programs Office (LPO) via the Energy Infrastructure Reinvestment (EIR) program to support \$250 billion in loan-making authority to facilitate refinancing and reinvestment in capital projects at fossil infrastructure sites, using below-market interest rates. Funds can be used flexibly to “re-tool, re-power, re-purpose, or replace” fossil infrastructure across the entire energy industry (including non-utilities), reducing the cost of replacement resources and creating numerous pathways for community diversification and redevelopment. The financing provisions are flexible enough to work for all parties—utilities, consumers, and communities. These stakeholders can use the financing to reduce the near-term rate impacts of capital transition, allowing new investment to arrive sooner in these communities that sorely need it as aging fossil plants ramp down.

Second, the IRA authorized a \$9.7 billion program specifically for rural electric cooperatives through the U.S. Department of Agriculture (USDA). Rural electric cooperatives provide electricity to more than 40 million people. Their power supply is particularly coal-heavy, with coal accounting for 28 percent of generation in 2020 compared to 19 percent nationwide.<sup>19</sup> This means surrounding rural communities bear a disproportionate burden of coal-related pollution, while member-owned cooperative customers remain tethered to coal debt. While members may want to transition to clean energy to capture pollution and cost savings, this debt holds them back. Furthermore, simply shutting down cooperative coal plants could impact communities that rely on relatively high-paying jobs where economic opportunities are sparse. To address these challenges, the IRA funds USDA to provide direct grants or loans for rural electric cooperatives to procure clean energy, with an express purpose of reducing GHG emissions.

## METHODOLOGY

As in the previous two coal cost crossover studies, this report compares the marginal cost of energy (MCOE) for existing coal plants across the U.S. with the LCOE for solar and wind. We compare the same coal costs to four different cost scenarios for renewables. Scenarios vary by resource type

(wind or solar) and by geographic scope (regional or local). For the first two scenarios, regional solar and regional wind, we separately examine the costs of solar and wind located within the same region as a given coal plant, calculating the LCOE to replace each plant's annual generation within a nearby region that corresponds roughly to the utility's service territory.<sup>vi</sup>

For the last two scenarios, local solar and local wind, we look at local costs for solar and wind separately, calculating the cost if all replacement renewables are sited within a 45 km radius of the existing coal plant. Local solar and wind projects get the additional energy community tax credit bonuses in the IRA, which helps to offset losses in power resource quality due to the local siting constraint. A more detailed explanation of our methodology is available in this report's Appendix.

## Coal Economics

To calculate the MCOE at each coal plant, we sum three cost components: the cost of fuel, the fixed and variable costs of operations and maintenance, and the going-forward routine capital expenditure costs, each calculated on a per-MWh basis. Using 2021 U.S. Energy Information Administration (EIA) data, we calculate the total going-forward marginal cost for all coal plants operated by utilities or independent power producers in the continental U.S., excluding plants that are used for co-generation of heat. These costs appropriately comprise marginal cost because they would not be paid if the coal plant retired. By contrast, we do not include unpaid capital balances as part of the MCOE because their payment does not depend on whether the plant retires.<sup>vii</sup>

## Renewable Economics

We used NREL's Regional Energy Deployment System (ReEDS) model to calculate solar and wind LCOE values, which are all-in estimates of the cost of energy output in MWh, taking into account all capital expenditure, operations, and maintenance costs. We used the 2021 actual cost values from the 2022 NREL ATB.

The ReEDS model uses solar and wind resource potential values at around 50,000 sites across the country, accounting for comprehensive exclusion criteria, including land cover, elevation, slope, environmentally sensitive areas, and local siting regulations. The model also provides annual capacity factors at each of these sites. The site-specific LCOE is then calculated based on capacity factor, as well as a comprehensive list of parameters including capital costs, fixed operation and maintenance costs, equity costs, interest rates, construction costs by location, construction period,

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<sup>vi</sup> We use regions defined by NREL's Regional Energy Deployment System model, explained in detail in the appendix.

<sup>vii</sup> These remaining balances are the primary target of the reinvestment programs created by the IRA. Though we don't include the balances in our cost calculations, the potential to refinance and replace with clean energy is another path toward reducing coal generation beyond operating costs.

IRA tax credits, and depreciation. We calculate the LCOE after accounting for both the ITC and PTC 2022 tax credit values, using the cheaper of the two.

### Renewables key assumptions

Across the four renewable scenarios, we make several key assumptions:

- Regional solar and wind costs include new grid interconnection costs, while local resources do not.
- All renewable resources qualify for the prevailing wage and apprenticeship hour tax credit bonus.
- All wind resources qualify for the full domestic content bonus, while 42 percent of solar resources qualify for the domestic content tax credit bonus based on current domestic content levels.<sup>20</sup>
- Storage does not qualify for the domestic content credit bonus.
- All tax credits are reduced by 10 percent to account for transfer losses.

### Regional renewables scenarios

For the two regional renewable cost scenarios, regional wind and regional solar, we start by finding the LCOE for regional wind and solar that could replace each plant's 2021 annual generation. The region we study for each plant is based on the ReEDS balancing area (of which there are 134, see Appendix) in which the plant is located, corresponding roughly to the utility territory. For each coal plant, we sort the wind and solar sites available in that region by LCOE and choose the best sites based on capacity factor to replace the coal generation. For selected sites within each region, we capacity-weight the site-level LCOEs to estimate the weighted average regional LCOE. Interconnection costs associated with transmission lines that connect the project to the grid are also added into these LCOEs, while we make no assumption about broader grid impacts.

### Local renewables scenarios

For the local wind and local solar scenarios, we first determine the viability of the local wind or solar replacements for each coal plant. Using the plant's latitude and longitude as the center, we create concentric circles around each coal plant, starting with a radius of 5 km and moving up to 45 km in 5 km increments. We identify the solar and wind sites that fall within each of these concentric circles and separately estimate the site-level capacity and annual generation potential for solar and wind resources. We then estimate the minimum radius needed to replace the annual generation from each coal power plant with solar or wind resources.

If there is enough generation found within the 45 km radius, we then determine the local LCOE by capacity-weighting the site-level LCOEs for the maximum radius needed to match the existing

plant’s generation. For solar, nearly all plants meet the generation requirement within a 20 km radius while for wind, the average radius is much larger and there are many plants without enough wind generation within 45 km because of the more site-specific nature of wind energy potential and the larger land footprint (see Figure 3).

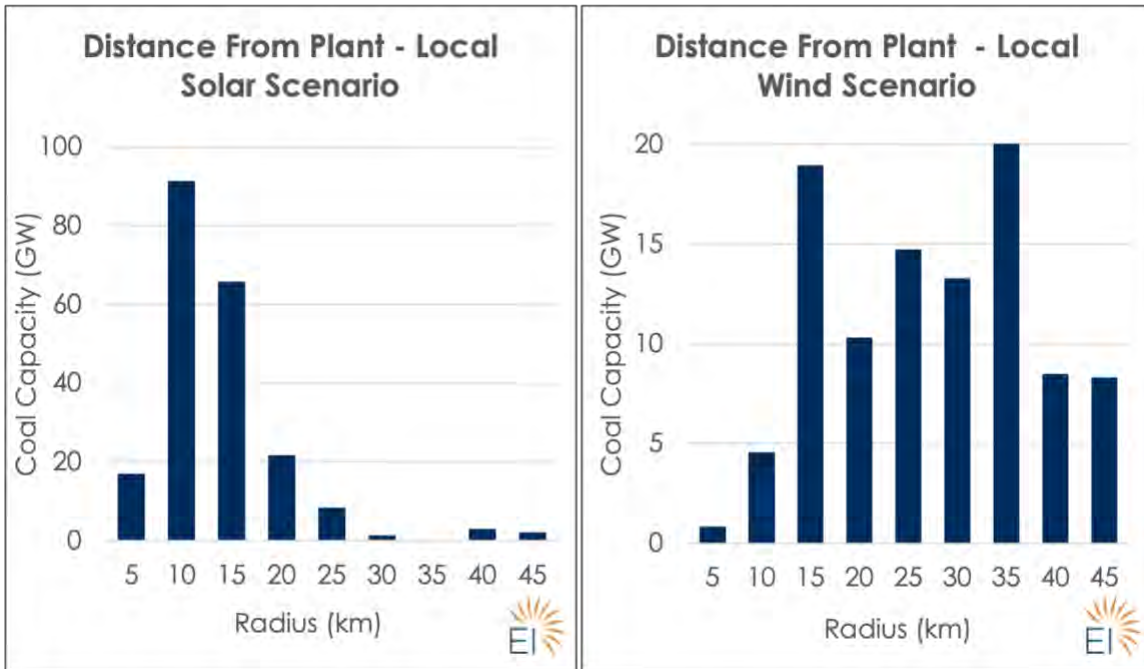


Figure 3. This figure plots the radius needed to match each plant’s generation, while still being cheaper than coal, for both local solar and local wind. The majority of coal capacity has enough solar potential within a 20 km radius to meet the plant’s entire annual generation in our local analysis and still provide cheaper energy than coal. While many plants have sufficient and cost-effective local wind nearby, less potential is available in close proximity for local wind.

For the local scenarios, we assume that all projects sited within 45 km of the plant will receive the IRA’s 10 percent energy community bonus tax credit, given that both the census tract and neighboring census tract to any retiring coal plant fit the IRA’s definition of an energy community. For these scenarios, interconnection costs are not included in the LCOEs as we assume that the new resources can utilize the existing plant’s interconnection infrastructure.

### Storage analysis

For the local solar scenario, we also analyze the economic feasibility of installing four-hour battery storage capacity along with the solar to provide additional reliability services to the grid. For this analysis, we start with a \$330 per kilowatt-hour (kWh) price for the storage,<sup>viii</sup> and we include a 36

<sup>viii</sup> This price is based on the 2021 actual storage costs in the NREL 2022 ATB.

percent ITC (the full credit plus the energy community bonus, minus transferability losses). After calculating the savings from replacing the coal generation with local solar generation, we then determine how much battery capacity those cost savings would fund. Due to uncertainty in the battery price going forward, we calculate the battery capacity funded for storage prices ranging from \$100 to \$400/kWh.

## RESULTS & DISCUSSION

Main findings:

1. >99 percent of plants studied are more expensive to run than to replace with new renewable wind or solar energy.
2. >97 percent of plants studied are more expensive to run than to replace with either local solar or local wind energy within 45 km (approximately 30 miles) of the coal plant.
3. Replacing coal generation with local solar resources could drive up to \$589 billion in clean energy investment in energy communities across the U.S.
4. Replacing coal generation with local renewable resources could save enough to finance installation of 137 GW of four-hour battery storage—62 percent of the coal fleet’s nameplate capacity.

### Overall comparison between coal and renewable costs

For this report we combined elements of the two previous Coal Cost Crossover reports: We looked at replacing coal power with regional wind or solar resources *and* at replacing coal power with local wind or solar resources close enough to a plant to take advantage of its transmission connection and the energy community bonus tax credit. Across these four scenarios, we found that:

- 199 plants are more expensive to run than to replace with regional wind.
- 190 plants are more expensive to run than to replace than regional solar.
- 104 plants are more expensive to run than to replace than local wind.
- 199 plants are more expensive to run than to replace than local solar.

Analyzing these scenarios together, we found all but a single coal plant<sup>ix</sup> in the dataset of U.S. coal plants to be more expensive (lower renewable LCOE than coal MCOE) compared to replacement by at least one of these renewable options. Between local solar and local wind, 205 out of 210 plants had at least one cost-effective local renewable option. Of these, 98 had *both* local solar and local wind options that were cheaper than coal (see Figure 4). This represents a sharp acceleration

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<sup>ix</sup> The single coal plant is the Dry Forks Station in Wyoming. It is the newest and among the cleanest coal plants in the U.S. coal fleet and is still only \$0.32/MWh cheaper to operate than available regional wind. It is also a testbed for carbon capture use and storage (see <https://www.powermag.com/dry-fork-a-model-of-modern-u-s-coal-power/>). A similar plant built today would include capital costs and would not be competitive with new renewables.

in the previously observed trend in our coal cost crossover reports (see Figure 5). The full results of all four scenarios can be viewed in the accompanying [spreadsheet](#).

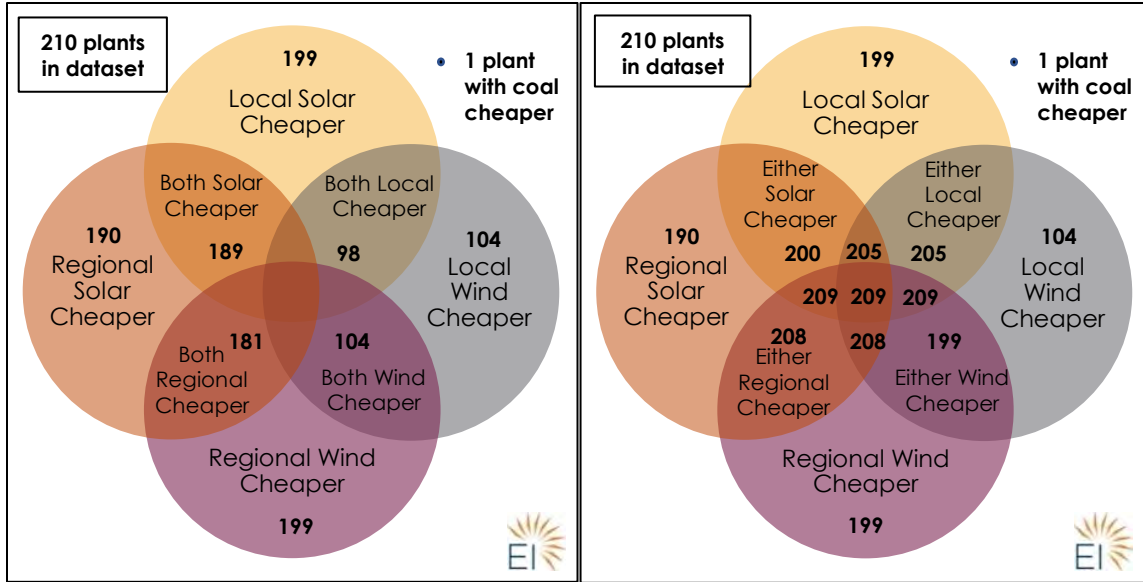


Figure 4. A closer look at the 210 coal plants in our data set based on the specific comparison with renewables that was made. The Venn diagram on the right looks at inclusive intersections (either resource is cheaper than coal) while the one on the left looks at exclusive intersections (both resources are cheaper than coal). We did not analyze any hybrid combinations of wind and solar, although this is clearly a possibility in the local context (98 plants) and the regional context (181 plants).

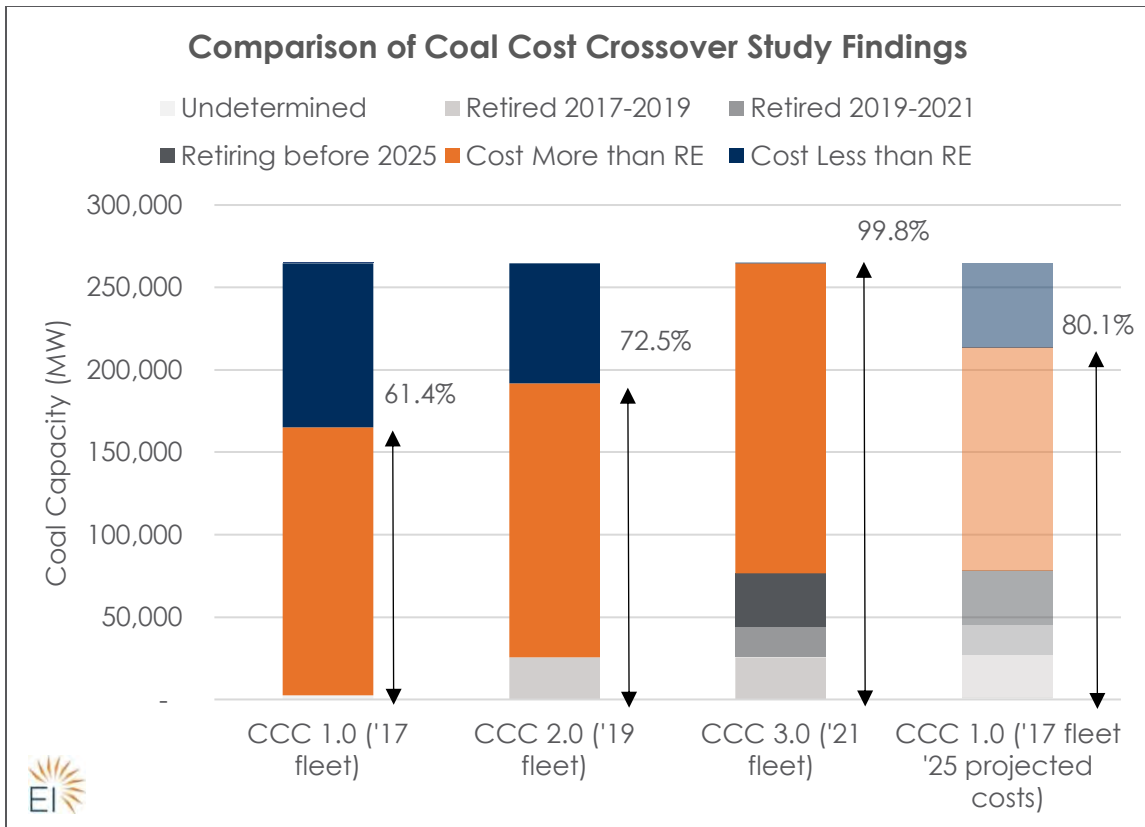


Figure 5. Comparison of our two original analyses of renewables and coal cost-competitiveness. The first included a 2025 projection for renewable costs to compare with 2017 coal going-forward costs. This comparison highlights how much the trend for coal being uneconomic compared to replacement by renewables has accelerated since the first report published in 2019.

### Comparison between coal and cheapest available wind or solar resource

For the plants that were uneconomic, multiple renewable options were less expensive than coal generation, but regional wind and local solar were most frequently the cheapest overall resources (see Figure 6 and Figure 7). Regional wind was the cheapest option for 117 plants, while the most economic resource was local solar for 75 plants, local wind for 13, and regional solar for only four.

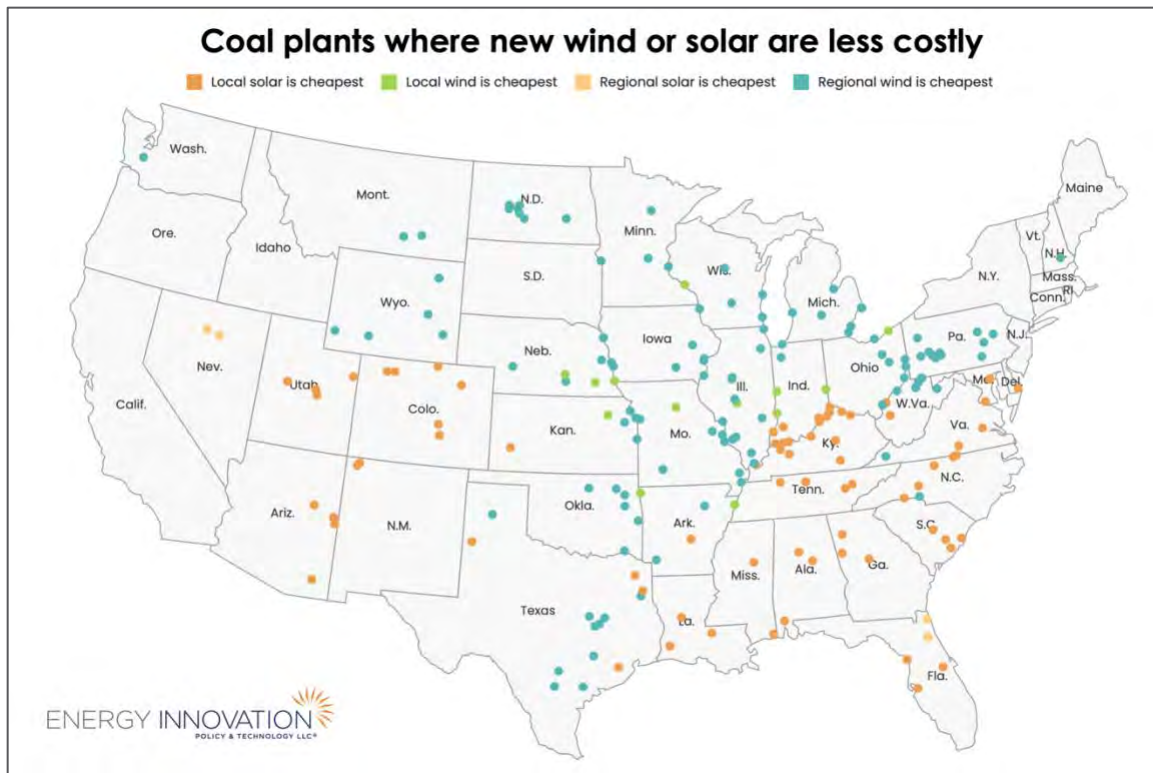


Figure 6. While most plants have multiple cheaper renewable options, the overall cheapest renewable resource varies by geography.

Notably, for solar, local replacement is cheaper than regional replacement in many cases due to low regional cost variability, lower transmission spur line costs,<sup>x</sup> and IRA energy community bonuses. For regional versus local wind, however, regional resources tend to be cheaper even with the added costs due to higher variation in resource quality for wind—going further from the plant often yields significantly better wind energy sites.

<sup>x</sup> A “spur line” is the transmission line that connects a renewable project to the bulk system at a point of interconnection. In this analysis, we do not make assumptions about interconnection costs beyond the cost of building the spur line. In this limited respect, we anticipate that local wind and solar costs would be lower than regional renewables, because local renewables are adjacent to the coal plant’s point of interconnection. We recognize that interconnection costs for renewables have been increasing for a variety of reasons as they sit in ever-growing interconnection queues around the country, but also hypothesize that some renewables could reuse existing coal plant interconnection rights with very low interconnection costs. See <https://emp.lbl.gov/news/pjm-data-show-substantial-increases>.

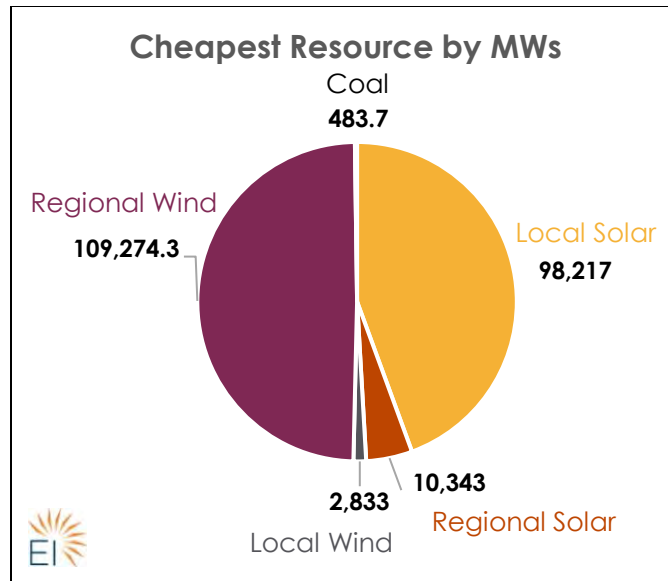


Figure 7. This chart shows the cheapest renewable resource option for each MW of coal capacity studied in this report. Local solar and regional wind are the cheapest renewable resources for nearly all plants.

We still see a wide range in the relative economics between existing coal and new wind or solar, with the all-in costs for the cheapest renewable option anywhere from zero (for one plant) up to 80 percent cheaper than the going-forward costs for coal, absent a few edge cases. Typically, the least economic plants have low capacity factors that result in very high fixed marginal costs per MWh or very high fuel costs.

For more than three-quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace (see Figure 8).

The substantial cost savings from replacing coal with renewables indicates the potential to invest in additional resources that provide complementary services like flexibility and transmission, without raising costs. Policymakers should consider a portfolio of clean resources that together provides adequate value and any needed reliability services. These resources could include storage,

regional or interregional transmission upgrades, demand-side resources, and complementary portfolios of wind and solar.

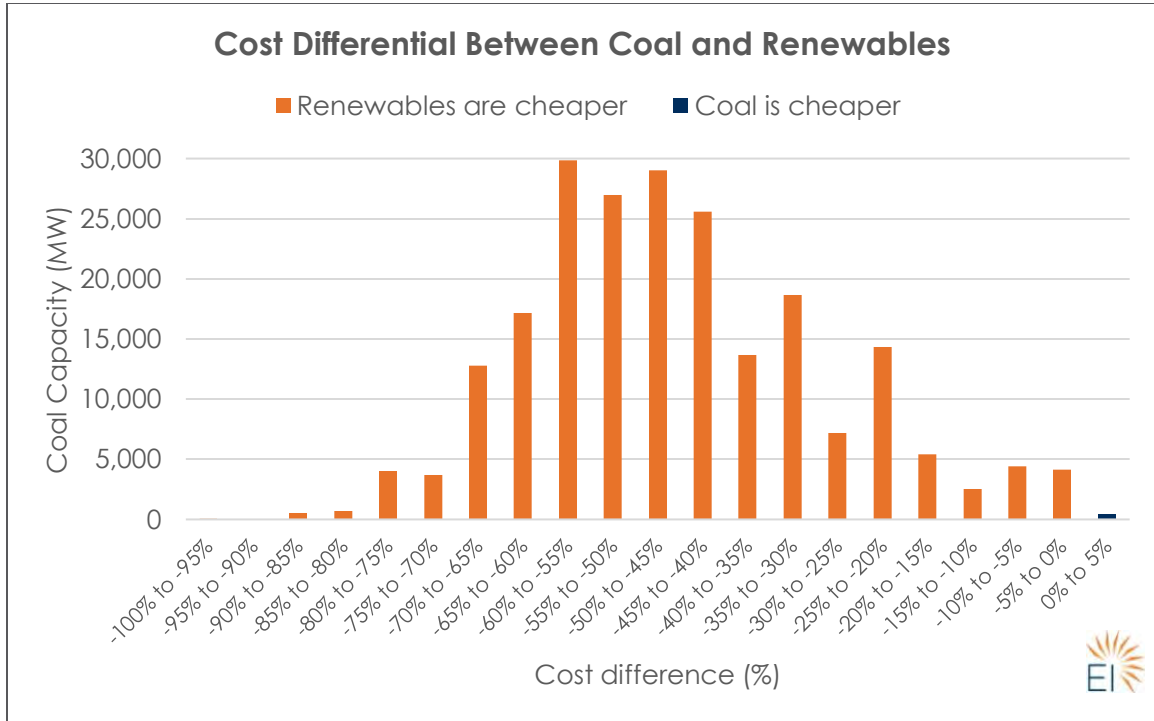


Figure 8. Aggregated plant capacity shown as percent difference between renewables LCOE and coal going-forward cost. The orange bars indicate capacity where renewables are cheaper than coal and coal is deemed "uneconomic." The one blue bar indicates the sole plant that is still cheaper to operate than replace with renewables.

### Local replacement of coal

#### Local solar and wind

For 199 of the 210 plants studied we find that local solar replacement is more economic than coal, based on energy generation alone, and for 75 plants it is the cheapest option entirely. Local wind is also a viable option for many plants, with 104 plants having cost-effective local wind resources and 13 having local wind as the cheapest option. For 98 plants, both local wind and local solar were

cheaper than coal. While we did not study any combinations of the two, this result indicates that a portfolio that includes both local wind and local solar would likely be a viable option with additional reliability value near many plants.

In these local replacement scenarios, we looked at replacing all the annual electricity generated by a given coal plant with either local wind or local solar within 45 km of the plant. This allowed us to assume lower interconnection costs<sup>xi</sup> (a significant barrier for new projects)<sup>21</sup> while taking advantage of the IRA's energy community tax credit bonus. In nearly all cases we studied, the reduced interconnection costs and added tax credit compensates for potentially lower resource quality when restricting site selection in areas close to the plant. We find particularly good resource quality in the local solar scenario, where 191 plants have sufficient sites nearby such that their generation can be replaced within 20 km.

Local replacement offers three other benefits. First, local replacement can help preserve livelihoods and tax revenue for surrounding communities through the energy transition.<sup>xii</sup> Second, local resource replacement falls into the category of projects that can qualify for loans via the DOE's

### Solar plus storage stepping in at North Valmy

In Nevada, NV Energy has already realized the cost and community benefits of using solar plus storage in place of the 567 MW North Valmy Generating Station, near Winnemucca. Two new solar plus storage facilities located within the same county will replace this plant when they are completed by 2025. The two replacement projects will provide 250 MW solar capacity plus 200 MW of storage, and 350 MW of solar plus 280 MW of storage. These projects will also create several hundred construction jobs, and the storage will help shift the solar generation to the times of day it is most needed, serving the reliability needs of the area. This is consistent with our analysis, which finds that it would be cheaper to use solar plus storage up to the full plant's capacity than to continue to run the coal plant. Plants across the country can now follow Valmy's example and effectively decarbonize with solar plus storage.

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<sup>xi</sup> In our modeling, we use ReEDS spur line costs as a proxy for interconnection costs of regional renewables. For local renewables, we assume no interconnection costs because the point of interconnection already exists at the coal plant. This is a simplification—each site will be different and will require an interconnection study or transmission plan to ascertain the interconnection costs.

<sup>xii</sup> New renewable energy installations are only one piece of the puzzle when it comes to community transition as they typically do not provide as many jobs or as much tax revenue as a coal plant. While local energy replacement can contribute, further community re-development and economic diversification is needed, as discussed further in the policy recommendations section.

EIR program, as the projects would be a direct reinvestment in energy infrastructure. Our analysis shows investment in local solar resources could drive \$589 billion in capital investment to energy communities across the country (see Figure 9).

Third, siting renewables in proximity to plants creates the possibility that these new resources could use the existing plant’s grid interconnection. Recent analysis of PJM’s interconnection process shows that the median interconnection cost from 2020 to 2022 grew ten-fold over the costs from 2017 to 2019, largely due to transmission network upgrade costs.<sup>22</sup> While we considered reduced interconnection costs for local resources, the advantage of local replacement could be even more considerable as the cost of the line is only a part of the problem. For clean energy projects across the country, long interconnection wait times are also a major hurdle to overcome.

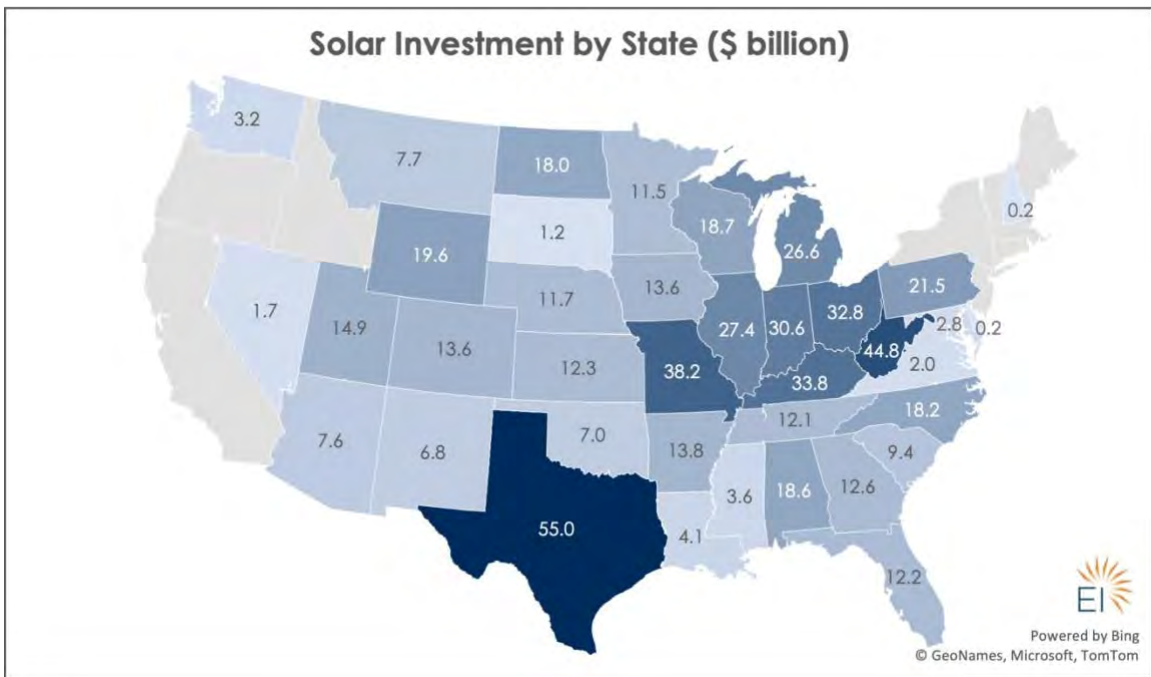


Figure 9. The solar capacity needed to provide enough energy to make up for coal generation across the country would drive hundreds of billions in investment. States with no investment number had no plants in our data set.

### Local solar plus storage

We followed up on our local solar scenario by looking at a solar plus storage replacement option for each plant that includes local solar energy plus four-hour batteries to provide additional capacity value and higher market profitability in some cases. We find that the savings available from switching from coal generation to local solar generation can finance 137 GW of four-hour battery capacity at a price of \$330/kWh across the coal fleet.

For more than a third of the coal capacity studied, we find that in addition to energy generation replacement with local solar, 80 percent or more of the plant's capacity can be replaced with four-hour batteries at a combined levelized cost that is still less than the going forward cost of the plant. For the remaining plants, the percentage of capacity that can be economically replaced is still quite significant: We find that savings from renewable generation could fund storage at more than 50 percent plant capacity at 136 plants.

### **Renewable options cheaper than expensive upgrades at Mitchell plant**

In 2021, American Electric Power determined it would likely be more cost-effective to retire West Virginia's Mitchell Power Plant than pay for expensive pollution control upgrades required by the U.S. Environmental Protection Agency (EPA). However, the West Virginia Public Service Commission (PSC) ruled that the utility had to keep the plant open, and that WV ratepayers must pay for the upgrades. At the same time, in Kentucky and Virginia, who were also receiving power from the plant declined to make their state's customers pay, leaving West Virginians to shoulder a \$448 million price tag. Our analysis shows taking advantage of regional wind resources would be 48 percent cheaper than continuing to run this polluting plant. Replacement with local solar and battery storage would be 50 percent cheaper and would provide the reliability the PSC seeks while saving ratepayers hundreds of dollars every year.

This local solar plus storage arrangement has at least three advantages:

First, solar plus storage provides resources with a significant capacity and ancillary service value at the same place on the power grid, addressing in part possible reliability concerns that may be associated with coal plant retirement.

Second, the new storage ITC means batteries do not need to be co-located with renewables to take advantage of the tax credit. This means that while local renewables may need to be sited a short distance from the plant, storage can be placed directly at the coal plant site and use existing electrical infrastructure to act as a central collection site for renewables. This arrangement also bolsters economic development opportunities in coal communities.

Third, combining solar and storage empowers a gradual coal phase-out, benefiting communities and grid reliability. Electricity generated from coal can be reduced, while keeping the coal boiler and generator available for emergencies. If needed, the generator can eventually be transformed into a piece of grid regulation hardware requiring no boiler, and batteries can store and release renewable energy to make the whole system available at times of highest grid demand. Renewable energy can

be a part of an economic diversification package that may include other re-purposing of the site, such as a plant in Michigan that was re-developed into an insurance company’s headquarters.<sup>23</sup>

The reliability implications of coal plant retirement should be evaluated for each specific plant. A one-to-one replacement is often not necessary given the capabilities of the remaining power plant fleet. For example, the battery capacity necessary to take over the reliability burden of any given coal plant is varied, depending on the role of the plant and broader resource mix, and it is not needed at all in many cases. Wind and solar (especially in a complementary combination) already tend to provide a measure of capacity value to the regional grid. Other assets like faster, more flexible gas units or behind-the-meter resources may already be carrying more of the regional reliability burden, and transmission expansion can help reduce the need for dispatchable generation for resource adequacy as well. Therefore, coal capacity is not always necessary for reliability depending on the resource adequacy in each region as determined by the balancing authority.<sup>24</sup>

Figure 10 shows the percentage of battery capacity at each plant that can be funded by coal replacement with local solar, providing a range of options for combining renewables with storage.

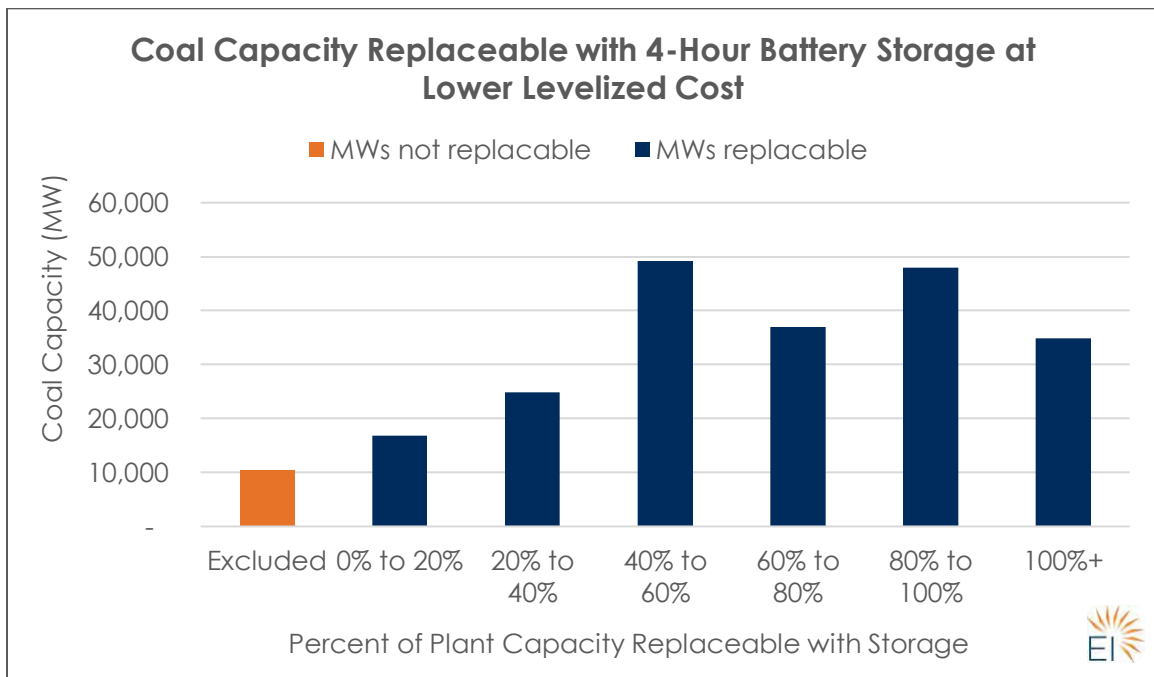


Figure 10. Coal plant capacity (in MW) by the percentage that can be replaced using only coal crossover savings. “Excluded” indicates plants for which local solar generation was available but was not cheaper than coal.

The economics of battery replacement for capacity are highly dependent on battery costs. For the analysis above, we used \$330/kWh as the cost of storage, which is the 2021 cost for storage in the NREL 2022 ATB.<sup>25</sup> Our cost accounted for the new standalone storage ITC and energy community tax credit. To study the sensitivity of these findings to battery prices, we evaluated the potential for capacity replacement across prices ranging from \$100/kWh to \$400/kWh (see Figure 10).

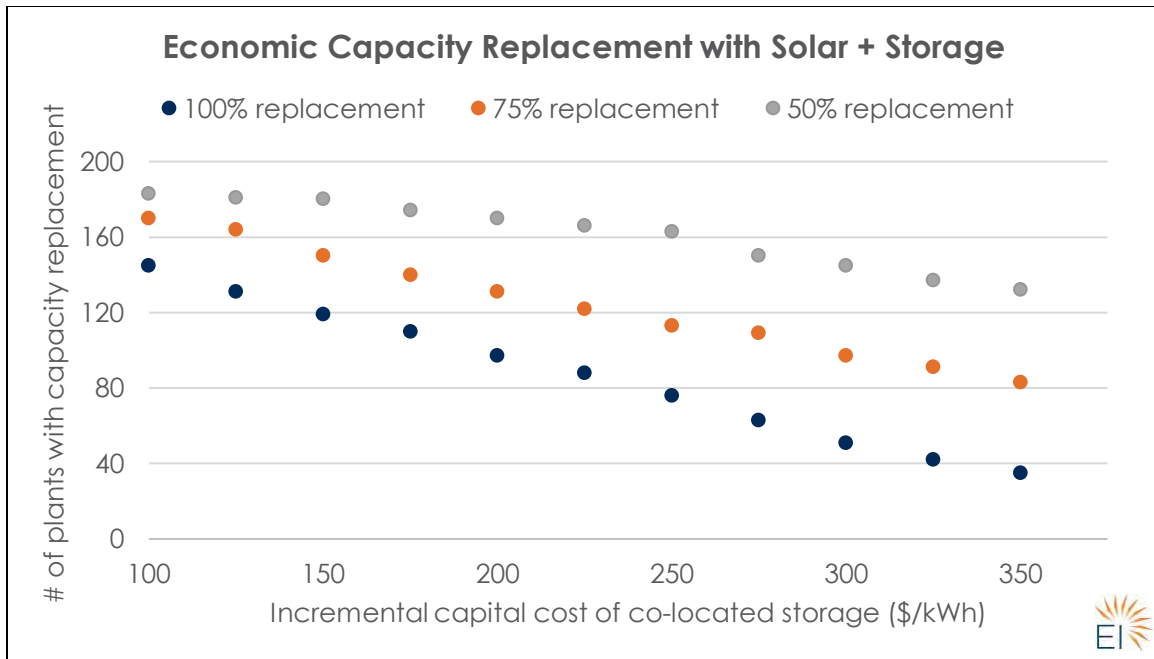


Figure 11. Economic battery capacity relative to battery price by percent capacity that can be replaced at each plant.

#### Utilizing additional financing to fund local resources: Ameren’s Rush Island Plant

It is important to note, however, that fuel savings are not the only source of savings that could help finance replacement batteries in a coal-to-local renewables swap.

For example, Ameren’s Rush Island power plant in Missouri is not a strong candidate for financing batteries solely with savings from switching to local renewables. Yet by also accounting for needed upgrades, the plant’s remaining balance, and reliability concerns, the case for financing batteries for reliability value becomes stronger.

Ameren was planning to retire the 1,195 MW coal plant in September 2022 partially due to the expense of adding court-ordered selective catalytic reduction (SCR) to address air pollution

noncompliance, with a price tag of \$310 million<sup>xiii</sup> to \$1 billion.<sup>26</sup> Unfortunately, because early retirement could cause severe voltage stability problems leading to cascading power outages, the Midcontinent Independent System Operator (MISO) sought to keep the plant online and received Federal Energy Regulatory Commission (FERC) approval for a 12-month system support resource agreement to be renewed annually.<sup>xiv</sup> According to the grid operator, potential renewable energy additions or possible demand-response programs wouldn't adequately address the location-specific voltage problem. However, due to the geographic nature of the potential voltage instability, local renewables coupled with batteries could go a long way toward mitigating this concern without waiting for the transmission upgrades MISO deemed necessary.

Our initial analysis finds that switching to renewables could generate savings to pay for replacing replacement of only 4 percent of the plant's capacity with batteries. However, the IRA now creates new possibilities. Because Ameren faces capital expenditures in the \$300 million to \$1 billion range, and already holds an estimated \$600 million for the plant in its rate-base (interest on which is paid by its customers at standard utility rate of return), existing state public utility commission securitization authority could be used to refinance this obligation in combination with the EIR program, generating much greater customer savings.<sup>xv</sup> Investing these savings in four-hour battery storage could match 85 to 165 percent of the plant's capacity. Furthermore, batteries would only be necessary if the local renewables on their own were not sufficient to provide voltage support or if the proposed transmission solutions proved too slow or expensive.<sup>xvi</sup>

New IRA financing and tax credits make replacing coal plants with a combination of local wind and solar power supported by batteries an attractive option for most coal plants in the U.S. Such replacement can be done with a minimum of disruption to the grid while keeping jobs in affected communities—not to mention the great improvements to public health from reduced pollution.

## POLICY RECOMMENDATIONS

Our analysis makes it clear the comprehensive the IRA tax incentives have created a favorable policy environment for the coal-to-clean transition. However, the transition can be made even more cost-effective if utilities harness the IRA's loan and grant programs and use best practices to assess cost-saving replacement options.

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<sup>xiii</sup> Assuming \$250/kW all-in costs. See <https://www.powermag.com/estimating-scr-installation-costs/>.

<sup>xiv</sup> MISO identified four transmission upgrades that are needed to maintain voltage on the grid, with the last one expected online by June 2025, according to the grid operator. See <https://www.utilitydive.com/news/ameren-missouri-coal-rush-island-miso-ferc/630226/>.

<sup>xv</sup> The interest rate on the securitized loans or government-backed loans through EIR are assumed to be 2.95 percent, or the average of the 20-treasury yield across the last 10 years plus 0.375 percent. Missouri law already allows for coal plant securitization.

<sup>xvi</sup> While MISO investigated replacement of the plant with renewable energy, it does not appear that MISO considered renewables in geographic proximity to the plant.

Planners and policymakers should make sure they are not caught unprepared by a wave of retirements, and that replacement renewables and complementary flexible resources can be deployed in a timely manner. Advocates and policymakers interested in capturing the economic and public policy benefits of shifting away from coal can take several actions to ensure that power plant operators take advantage of the moment by requiring utilities to account for IRA incentives and funding programs in planning and procurement. Finally, our analysis suggests that IRA provisions designed to encourage a just transition for coal communities are well positioned to spur

### Reliability assessment keeping expensive Indian River plant online

Delaware's only remaining coal plant, Indian River Generating Station, was planned for retirement by June 2022—until the grid operator, PJM, requested it remain open until 2026. PJM had determined that transmission upgrades would be needed to stabilize the grid before the plant could be taken offline. The plant, which only has one remaining unit, is historically the worst polluter in Delaware and also the eighth most expensive plant we analyzed due to low capacity factor and high estimated fuel costs. Local replacement of this plant could assuage reliability concerns by providing generation and capacity needs at the same location on the grid. Our local analysis finds that 246 MW of storage could be funded via savings. At over 50 percent of the plant's capacity, this is a good candidate for re-assessment of reliability needs.

new investment in generation and grid balancing resources in the immediate vicinity of existing plants, but experience has shown that a just transition will only happen with the careful attention of legislators and regulators alongside local communities.

### Preparing the way for coal transition

Improving interconnection and transmission processes

The Rush Island Power Station example discussed above is not unique and blocking retirement of uneconomic plants due to broader system stability concerns and transmission requirements harms customers. To move forward while maintaining reliability, independent system operators (ISOs) and regional transmission organizations (RTOs) should proactively study solutions that can enable plant retirements. The alternative—overriding utility retirement plans and requiring FERC approval for expensive stopgap payments to keep high-cost plants running—is not good for utilities or their customers.

Our analysis shows that post-IRA, almost every coal plant has reached its economic tipping point. As pollution standards and clean energy policies continue to worsen coal

plant economics, ISO/RTOs will increasingly encounter situations where innovative resource

portfolios will be needed to economically and reliably replace coal plants, including transmission. As neutral arbiters of just and reasonable rates, system operators must be ready to enable cheaper electricity and public policy goals by allowing utilities to retire uneconomic plants. Proactive transmission planning and deployment, alongside improvements to interconnection processes are both crucial to prepare for uneconomic plant replacement.

Absent regulators stepping in, retiring a plant is much easier than building a new renewable project. Price signals may induce coal retirements before new renewable projects can be approved and built to take their place. The growing interconnection queue backlog is of particular concern here. As of 2022, the two largest power markets in the U.S., MISO and PJM, had about three times more renewables capacity waiting in the queue than they had existing coal capacity.

For PJM, this backlog was deemed insurmountable. While PJM works through its existing interconnection requests, it will not review new requests until early 2026. It is clear that additional measures to improve the interconnection process, including better regional transmission planning, are needed to avoid similarly extreme measures in the future.<sup>27</sup> FERC is currently considering interconnection policy changes, but state public utility commissions can also help by examining their state's queue and assessing whether proactive transmission buildout could connect cost-effective clean energy. In states outside an ISO/RTO, states hold sole responsibility for proactive transmission and planning process reform to reduce wait times and hasten the pace of in-state clean energy investment.

#### Building local: accelerating deployment while maintaining reliability

Action from FERC and other policymakers on interconnection reform and transmission buildout cannot come too soon. A recent brief from Lawrence Berkeley National Lab (LBNL) analyzing interconnection costs in the PJM region finds that, alongside the tremendous lengthening of the interconnection queue, interconnection costs have increased substantially in recent years.<sup>28</sup> The main driver behind these increases has been broader network upgrade costs, reflecting system changes due to the influx of renewables and the fact that optimal renewable sites are often far from the coal they might replace.

There is no doubt that variable renewable resources are fundamentally different from dispatchable fossil generators, but variability does not imply unreliability. Studies are clear: A coal-free U.S. electricity system can be dependable.<sup>29</sup> Yet renewables do require a different resource adequacy framework, which makes resource diversity, energy sufficiency, regional and interregional transmission, and demand response more important. As system operators design new resource adequacy metrics, regulators should support them by defining minimum resource adequacy requirements and soliciting cost information.<sup>30</sup>

In a high-renewables environment, interregional electricity transfer can help manage local weather variation, providing higher reliability at lower cost. RTOs and regulators can enable interregional

coordination by expanding planning areas or subsidizing transmission lines that provide for specific reliability needs. Finally, regulators and state legislatures can require resources that bolster reliability like energy storage has become a cost-effective way to integrate renewables, as this report shows. However, storage still lags in investment. A legislative storage mandate, like the one passed in California in 2013 can help accelerate storage deployment.<sup>31</sup>

Ultimately, building out the network to include and adapt to some of the best available renewable resources, evolving the bulk power system’s resource adequacy framework, and improving inter-regional coordination supports a least-cost, reliable electricity system given the new IRA incentives. But, as is evidenced by the delays described above, all this takes time. Building local resources closer to or at the same site as coal plants could dramatically accelerate clean energy deployment while providing significant incremental reliability value.

Prior to the IRA, local replacement was not always economic on an annual generation cost basis relative to the cost of maintaining a coal plant. However, to support a just transition, the IRA includes additional incentives for building new clean resources near coal plants or “energy communities.” Our analysis shows that local wind or local solar plus storage could create a cheaper electricity portfolio than nearly every plant, while delivering the same amount of electricity and providing significant reliability value. Even if a coal plant weren’t completely shut down, it could work in tandem with cleaner, cheaper resources fed through the same point of interconnection to deliver cheaper, cleaner electricity without materially affecting the transmission system and system operations (it might even improve these). Utilities, ISO/RTOs, and state and federal regulators should move swiftly to develop standard templates that allow for coal plant hybridization or replacement with clean portfolios. These templates would have to be generically robust enough to satisfy system reliability and stability concerns under a variety of conditions to replace coal without a lengthy interconnection process.<sup>xvii</sup>

## Proactively pursuing transition

### Re-evaluation of integrated resource plans and improving competitive procurement

While measures to proactively plan for and better accommodate new renewable projects are necessary to capture the huge economic benefits of transitioning expensive coal plants to cheaper renewables, they are not sufficient. Utility integrated resource plans routinely overestimate new renewable costs, and the IRA programs will likely make these overestimations even higher. Any

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<sup>xvii</sup> There may be concerns about undermining competition if some resources are allowed to skip ahead of the line, but presumably standard templates will involve costlier investments than what might be proscribed in a more specific interconnection study. In any case, it makes sense to recognize that providing replacement resources at or near an existing resource is easier and simpler for the network, and the benefits of just transition and accelerated deployment should be balanced against competition concerns.

investment plan or market-based solicitation for renewable contracts completed before August 2022 is now out of date. Regulators can expect independent power producers to offer lower bids for just about any clean energy technology. Under their authority to set just and reasonable rates, PUCs should insist that utilities redo integrated resource plans and resource solicitations, despite the procedural complexity. For example, advocates have already submitted evidence to the North Carolina Utility Commission that such a re-examination would be prudent for Duke Energy's Integrated Resource Plan and Carbon Plan.<sup>32</sup>

In addition to cost updates, integrated resource plans should account for the benefits of location-based procurement to replace coal generation. In New Mexico, the Energy Transition Act required the Public Service Company of New Mexico to site some of the replacement resources for the San Juan Generating Station in the nearby school district to replace lost tax revenue.<sup>33</sup> Because of location-specific tax credit bonuses, traditional regulatory requirements to minimize consumer costs now require an examination of local investment in replacement wind, solar, and battery resources.

FERC and NERC should work with the ISO/RTOs to create standardized approaches to gradual replacement with local resources and eventual development of reliable resource portfolios that include renewables, transmission, and emerging technologies like power electronics and synchronous condensers.

In addition to accurately assessing renewables during planning processes, enabling competitive procurement is crucial to getting steel in the ground. Even before the IRA, unsubsidized renewables were the cheapest new resource in most of the country. However, regulators can have difficulty discerning the true cost of clean energy or comparing variable clean resources with dispatchable fossil power providing different services. Such assessments generally depend on limited utility information.

All-source procurement is a way around this—it is a well-established but underutilized process that requires the utility to provide assessments of resource need, then bid these services to the market. For example, Xcel Energy Colorado achieved record-low wind, solar, and storage prices that shocked the electricity world with an all-source procurement in 2018, avoiding costly investments in gas and accelerating coal retirement.<sup>34</sup> PUCs should establish all-source procurement rules that link these solicitations as inputs to integrated resource planning processes that ultimately result in resource procurement—a key part of the Colorado planning process.<sup>35</sup> These solicitations also provide the opportunity to assess and define needed system reliability attributes after coal plants retire and allow supply-side, demand-side, transmission expansion, and regional market resources all compete to fill that need.<sup>36</sup>

## Utilizing IRA funding and financing programs

Our comparison of the going-forward costs of existing coal plants with regional or local renewables doesn't capture all the economic advantages of such a transition. The IRA also includes measures that facilitate savings from lower cost financing.

First, the IRA created a \$9.7 billion fund for rural electric cooperatives to reduce GHG emissions via a myriad of methods. With cooperative assets highly tied up in coal and without the same access to capital as investor-owned utilities, the transition to cheaper clean resources can be particularly challenging. To take advantage of these funds as soon as possible, co-ops should develop clear plans that use new clean energy and coal generation replacement to achieve deep GHG emissions reductions, in accordance with the IRA's statutory language.<sup>37</sup> For their part, states should provide resources to support the planning and application processes. With nearly 18 GW of plants in this analysis majority-owned by cooperatives, this program, if used to its greatest potential, could spur billions in rural economic development.

In addition to rural cooperative funding, the IRA provides substantial debt refinancing potential, when paired with reinvestment in new clean energy infrastructure. While we find all but one plant are uneconomic when compared to replacement with new wind and solar, many plants have large debt burdens that hamper the customer savings available from clean energy replacement. Some states have explicitly allowed utilities to refinance these remaining balances via securitization, but now all power plant owners have access to flexible low-cost capital to finance new clean energy projects reusing coal-

### Cleaning up coal ash at the G G Allen Steam Plant

In 2014, the now-retired Dan River Power Station leaked 39,000 tons of coal ash into the Dan River—leaving residents without drinking water for years and requiring a \$3 million clean-up. It also kicked off an investigation of Duke Energy in North Carolina that found all 14 coal plants in the state were leaking coal ash. G G Allen has the largest amount of coal ash on site out of all the plants with 19 million tons of that need to be removed. In addition to this high pollution impact, it is also the second most expensive coal plant to run in the U.S. according to our analysis. But it needn't be this way. North Carolinians can have clean air and water with cheaper clean energy. All four renewable scenarios in our analysis were cheaper than running the G G Allen plant. In addition to clean energy replacement, the use of a DOE loan guarantee could save ratepayers even more by using low-cost financing for replacement infrastructure including the coal ash remediation.

plant infrastructure via the DOE’s new loan program.<sup>38</sup> PUCs should require utilities to update prior investment and coal retirement plans to reflect the low-cost capital now available for reinvestment in communities.

Particularly for independent power producers, which own 23 percent of the coal capacity we studied, these DOE loans will be significantly cheaper than those without government backing. The

### **Just transition in Colorado**

In 2019, the Colorado legislature passed a bill creating the first Office of Just Transition (OJT), and just in time. With six coal mines and seven coal-fired power plants still operating, small communities, particularly in Western Colorado, risked near-total economic collapse. Since the legislation passed, the OJT created a Just Transition Action Plan to support economic diversification and job retraining. The town of Nucla illustrates how this plan can work. When their coal plant shut down three years ahead of schedule, it was the largest employer. The plant also provided nearly half the tax revenue that supported the whole region—including the fire department and school district. Residents were rightfully concerned, but Nucla has worked with OJT to transition their economy to focus on tourism and small businesses. Nucla still has a way to go and more funding is needed, but Nucla shows how pre-emptive planning can help ease the sting of coal closures. Now, newly appropriated OJT funds will continue to help Nucla restructure while preparing other Colorado coal communities.

loan guarantee must be used to reduce GHG emissions and reinvest in that same community.<sup>39</sup> Funds can be used for a wide range of applications including partial or full coal replacement with renewable resources, transmission and storage, and even remediation of former fossil fuel sites, improving environmental conditions and serving as another source of job creation for the local community. Given the flexibility of the program, this is far from an exhaustive list. To smooth community transition, loans need not require immediate plant retirement, but instead could support projects that gradually reduce coal while increasing renewable generation and diversifying the community’s economy.<sup>40</sup> The local renewable replacement plus storage scenario we study fits this approach.

### **Just transition for affected communities**

State PUCs, legislatures, and state energy offices all have a role to play ensuring a just transition for coal communities. New IRA funding mechanisms mean traditional, least-cost utility planning practices now require reinvestment in communities whose economic prosperity depends on coal plants and coal mining. Assessing and including reinvestment in

these places is now essential to “least cost, best fit” resource planning.

Of course, the nuances of community needs are more complex than simple economics, and fully considering viable transition strategies in integrated resource plans is not possible unless state regulators and utilities seek input from affected communities at the beginning of the planning process. Seeking community input is not typically part of existing integrated resource planning processes, and it can be challenging for resource-constrained PUCs or utilities to incorporate new, innovative approaches to stakeholder engagement and ultimately community transition.<sup>41</sup>

State legislation should require PUCs and utilities to plan for community transition and assess the value of federal loan guarantees and tax credits for community transition, starting with outreach in an investigatory proceeding that provides access by holding commission forums in those communities. With this input, utility investment plans can better meet community economic needs, which can include tax revenue, workforce development, infrastructure investment, pollution clean-up, and community ownership models like community solar.

While the IRA has several reinvestment programs, energy communities cannot rely on clean energy alone to fully replace coal jobs and tax revenue. However, local clean energy can provide the opportunity for additional industrial development if new data centers or industrial facilities like synthetic fuel producers seek direct on-site access to low-cost clean energy. Proactive diversification of local economies is another path for success, which would benefit from state resources. The transition can even begin before the plant retires—gradual replacement and interconnection could ramp up in anticipation of the plant’s eventual retirement, growing jobs and reducing pollution along the way.

Legislators should consider creating and funding a just transition office, following Colorado’s example, to help coal communities develop transition plans. In addition to these legislative actions, PUCs can consider putting community transition funding into rates or creating ratepayer and shareholder cost sharing arrangements, similar to the arrangement made following closure of the coal plant in Colstrip, Montana.<sup>42</sup>

## CONCLUSION

The economic case for replacing highly polluting and expensive coal-fired generation with clean energy is stronger than ever. Our new analysis, based on 2021 data, already surpasses our previous projection for 2025, finding that 99 percent of all U.S. coal plants are more expensive to run compared to new clean energy generation. Local replacement is more attractive than ever due to the IRA’s new incentive and funding programs. Including battery storage along with local renewable generation can be an economic way to bolster the reliability value that these renewable projects provide to the grid. Building new wind or solar before completely retiring existing coal can be a recipe for success, a paradigm supported by the DOE’s new loan authority. The near-complete crossover of coal economics versus renewables makes the imperative to transition clearer than

ever before, but policymakers, utilities, consumers, and coal-dependent communities must recognize the benefits and seize this moment.

## APPENDIX: DETAILED METHODOLOGY

### Coal Costs

Our goal was to develop an accurate estimate of the going-forward cost of running U.S. coal plants using publicly available data from EIA, FERC, and EPA. In assembling a master list of U.S. coal plants, we restricted ourselves to plants running mostly coal (excluding wood waste and petroleum coke burning units) operated by utilities and independent power-producers (sectors 1 and 2, in EIA parlance), excluding plants used for combined heat and power, for which the economics are more complicated because these plants receive other revenues from providing heat.

As a matter of convenience, we limited ourselves to coal plants in the lower 48 states and excluded a few plants for various practical reasons like corrupted or unavailable data. The companion spreadsheet to this report lists these in detail. In any case, these cuts did not materially reduce the number of GWs of capacity we covered. Finally, we grouped boilers and generating units together at one location as single plants, while excluding boilers and generating units fueled mostly with natural gas. The final master list of 210 coal plants is available in the companion spreadsheet to this report.

The going-forward cost for each coal plant in our master list comprises three principal components

- The cost of fuel on a per MWh of coal generation basis.
- The operation and maintenance cost of each plant levelized over the total generation from each included boiler and generating unit.
- The average annual going-forward costs for capital investments needed to replace and upgrade part of the power plant levelized over the total generation from each included boiler and generating unit.

This Appendix reviews our methodology for each of these three elements in more detail.

#### Cost of Fuel

Our principal method for calculating fuel cost for any given coal plant comes from first computing its cost of energy inputs in dollars per million British Thermal Units (\$/mmBTU). We need a heat rate in mmBTU/MWh to convert this input into a cost of delivered energy in \$/MWh. The heat rate is a number particular to any given plant that varies according to any number of contextual factors (e.g., fuel-type, technology, age, outside temperature, capacity factor). As a matter of simple expediency, we use a heat rate for each power plant defined by the sum of BTUs from all non-

natural gas fuels burned at that plant in 2021 divided by all the net-generation from these fuels as defined in the first page of EIA Form 923. We used this to convert input fuel costs into output electricity fuel costs.

We then used EIA data on fuel contracts paid by the plant; listed on page 5, “Fuel Receipts and Costs,” of EIA Form 923. The EIA 923 spreadsheet lists fuel contracts with heat contents (mmBTU per fuel unit) and price paid in cents per mmBTU. From these contracts we can establish an mmBTU-weighted cost per mmBTU for coal, which we use as an input cost for that plant. Note that this does not include fuel processing costs that might be covered in values reported to FERC. Probably the most important example of fuel processing comes from plants that report burning so-called “refined coal” on one part of Form 923 while at the same time reporting direct purchases of other coal, e.g., bituminous coal, on another part of the form. This discrepancy is due to the fact that “refined coal” involves processing purchased coal (usually by spraying it with certain chemical agents) to reduce emissions from the smokestack. It is hard to know how much this extra processing costs on a per mmBTU basis, but we understand that the economic rationale for doing so is driven mostly by a tax credit. Historical trend analysis of some plants that burn “refined coal” shows that they sometimes choose to apply this processing and sometimes not reflecting, in our opinion, the likelihood that there is only a small impact on fuel costs to “refining” after netting out processing costs and tax credit income.

For plants that do not report input fuel costs to a regulator, however, other less plant-specific sources of information were required. In these cases, instead of specifically reported plant data, we used state-based data on the average cost of coal from EIA. To accurately reflect the diversity of coal types and relative mix of types that various plants consume, we used a combination of total plant coal consumption and state average coal costs from EIA as well as historical fuel consumption trends at the plant to estimate source coal type and marginal fuel costs. We used the following procedure:

**Step 1:** Extract the various mmBTU quantities of coal by type used by the boilers in each coal plant of interest from the 2021 EIA Form 923.

**Step 2:** Link each coal type with a state benchmark input fuel price in \$/mmBTU. We establish that benchmark price by combining information on electric power sector coal prices by coal type and plant state from EIA’s Coal Data Browser with coal heat content (mmBTU/ton) by state and coal type, also from EIA’s Coal Data Browser (if heat content for a given coal type was unavailable for the 2021 reporting year, we used the most recent year).

**Step 3:** Tag “refined coal.” One type of coal that appears in boiler consumption figures but not price tables is “refined coal.” To price this type of consumption, we assigned each instance of “refined coal” to a coal sub-type. Depending on the plant, the source coal for “refined coal” might be bituminous, sub-bituminous, or lignite. With some painstaking work, we were able to infer from other nearby plants and historical fuel consumption trends at the plant which coal type was being refined with high confidence.

**Step 4:** Combine coal types to get a plant fuel cost. We combined price and consumption levels at each plant to get a weighted fuel input cost in \$/mmBTU. We then converted this to \$/MWh using the heat rate—just like the plants that report their input fuel costs.

### Operation and Maintenance Costs

We used plant-by-plant operation and maintenance estimates obtained from the Electricity Market Module (EMM) in EIA’s North American Energy Modeling Systems (NEMS). For some plants, no NEMS value for operation and maintenance was available and we used a national average value.

### Going forward capital costs — National Energy Modeling System (NEMS)

The third element in our overall coal going-forward cost estimate is the going-forward capital cost. For this element we used a fairly simple method. We started by taking the average age (weighted by generator capacity) of a given coal power plant and compared it to the EIA NEMS table found in Figure 12. From this NEMS table and the average age of the plant, we obtained a per kW-year going-forward cost, which we multiplied by the overall capacity of the plant. We then divided by the total net MWh output from the plant (defined by the included set of generators) as reported on EIA Form 923. This includes any natural gas-fueled generation and results in a \$/MWh, which then factors into the complete coal going-forward cost.

Age	Annual Capital Investment Requirement (\$/kW-yr)
0 - 10 years	\$ 17.16
10 - 20 years	\$ 18.42
20 - 30 years	\$ 19.68
30 - 40 years	\$ 20.94
40 - 50 years	\$ 22.20
50 - 60 years	\$ 23.46
60 - 70 years	\$ 24.72
70 - 80 years	\$ 25.98

Figure 12. NEMS estimates of going forward capital costs by age of plant.

## Renewables Costs

### Identifying Renewable Energy Sites

We use NREL’s ReEDS model that provides high spatial resolution solar and wind potential datasets in the U.S. The solar and wind potential numbers in ReEDS are, in turn, taken from the Renewable Energy Potential (ReV) model, which assesses the wind and solar energy potential at 11.2 km x 11.2 km spatial resolution after applying comprehensive exclusion criteria, including land cover, elevation, slope, environmentally sensitive areas, local siting regulations, etc. Across the continental U.S., ReV and ReEDS identify nearly 50,000 individual solar sites totaling a potential of 96,000 GW, and around 50,000 individual wind sites totaling a potential of 6,600 GW. The ReEDS model also provides annual capacity factors at each of these sites, which are estimated using the wind speed, solar irradiance, temperature, and other weather parameters from the Wind

Integration National Dataset (WIND) and National Solar Radiation Database (NSRDB). More information on this can be found in ReEDS documentation.

### Technology Costs

We run the ReEDS model using technology costs from ATB 2022 and IRA incentives and estimate the wind and solar LCOE at each of the 50,000 sites. ReEDS uses a comprehensive list of parameters to estimate a site-specific LCOE including capital costs, fixed operation and maintenance costs, equity costs, interest rates, construction costs differentiated by location across the U.S., construction period, ITC and PTC incentives per IRA, tax equity haircuts, depreciation, and taxes (see Figure 13). Additional details on LCOE estimation could be found in ReEDS documentation.

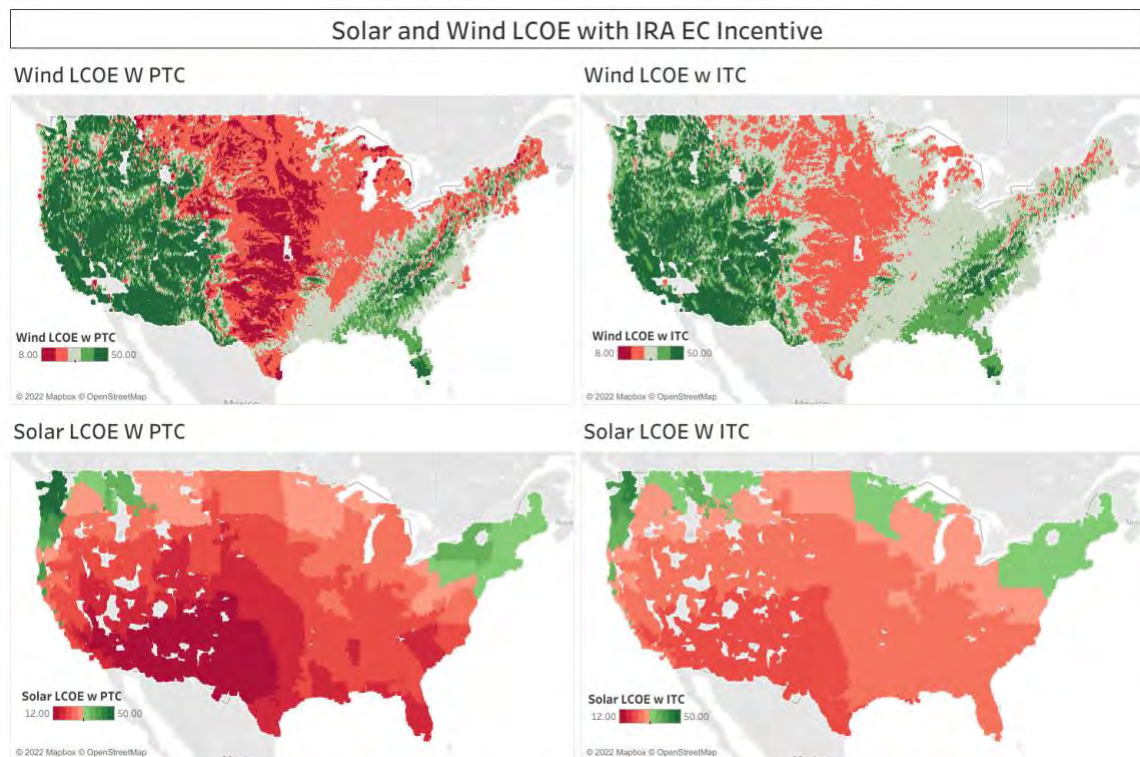


Figure 13. Wind and Solar LCOE including IRA incentives (including energy community) at each of the individual 50,000 sites across the U.S.

## Assessing Hyperlocal Potential and LCOEs

The objective of this exercise is to assess the physically closest (hyperlocal) solar or wind resources that could replace the generation from each coal power plant in the country. We start with the location (latitude and longitude) of each of the 210 coal plants in the US. We then create concentric circles around each coal plant with radiuses starting from 5 km up to 45 km in increments of 5 km. Within each of these concentric circles, we identify the solar and wind sites that fall within that circle and estimate the site-level capacity and annual generation potential for solar and wind resources separately, using the high-resolution solar and wind datasets available from ReEDS, as described earlier. We then estimate the minimum circle radius (“hyperlocal circle”) needed to replace the annual generation from each coal power plant with solar or wind resources. Within each hyperlocal circle, we assume that the solar and wind projects get the Energy Community Tax Credit per IRA and will not incur any interconnection costs since they could continue using the coal plant interconnection. We weight the site-level LCOEs within each hyperlocal circle by the site-level capacity potential to arrive at a weighted average hyperlocal LCOE to replace the generation from each coal power plant.

We find that annual generation at almost all coal power plants can be cost-effectively replaced by solar resources within a 20 km radius. The minimum radius for wind is much higher.

## Regional LCOEs

In addition to the hyperlocal LCOEs, we also estimate the regional LCOEs in the regions where coal plants are located. The ReEDS model divides the contiguous U.S. into 134 regions which are generally aligned with the utility territories (see Figure 14). These regions never cross state boundaries

The rationale for estimating the regional LCOEs in addition to the hyperlocal LCOEs is that the higher-quality resources might not be available in the near vicinity of the coal plants but slightly farther away, and so from the perspective of the developer, it might make sense to move further from the coal plants to access the higher quality resource. This is more important for wind as wind speeds can vary significantly over short distances. As compared to wind, solar is more energy dense, as we can get almost 10 times the capacity of solar in the same amount of land as wind.

The methodology used for estimating regional LCOEs is very similar to that of hyperlocal LCOEs. For each coal plant, we sort the wind and solar sites available in that region (i.e., ReEDS balancing area) by LCOE and choose the best sites to replace the coal generation. For selected sites within each region, we capacity-weight the site-level LCOEs to estimate the weighted average regional LCOE. For the regional LCOE, we do not account for the Energy Community tax credit available in IRA. We also add the interconnection costs to the LCOEs as we assume that these sites may not be able to access the existing coal power plant interconnection.

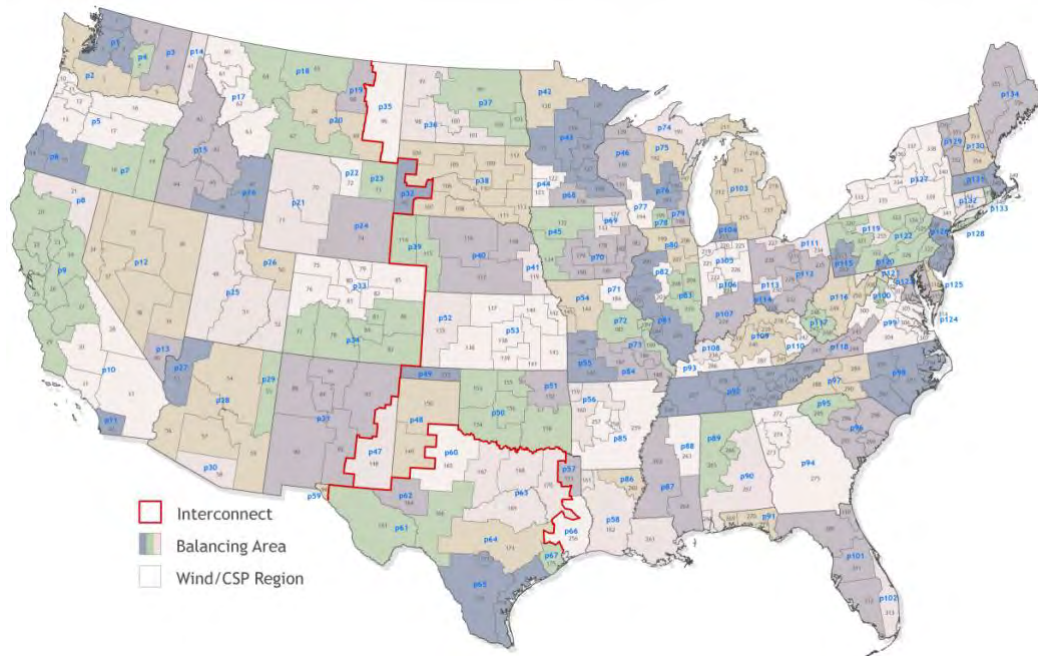


Figure 14. ReEDS balancing areas, used for our regional analysis and roughly corresponding to utility service territories, are highlighted by the different colors in this map. Source: National Renewable Energy Laboratory.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) )  
Emergency Order: Midcontinent )  
Independent System Operator )  
(MISO) )  
\_\_\_\_\_ )

Order No. 202-26-16

Exhibit to  
Motion to Intervene and Request for Rehearing and Stay of  
Public Interest Organizations

# Exhibit 52

## MI State Energy Profile



## Michigan State Energy Profile

### Michigan Quick Facts

- Michigan has 44 natural gas storage fields with almost 1.1 trillion cubic feet of underground storage capacity, which is the most capacity of any state and almost one-eighth of the nation's total natural gas storage capacity.
- The share of Michigan's total electricity generation from natural gas-fired plants increased from 12% in 2013 to 46% in 2023.
- Renewables provided 11% of Michigan's electricity net generation in 2023, with wind energy providing 64% of that power. Michigan ranks 16th among the states in the amount of electricity generated by wind energy.
- Michigan ranks fifth among the states in residential sector petroleum use and is first in residential sector consumption of propane.
- Michigan's second-largest power plant by capacity is the 2,186-megawatt Ludington pumped-storage plant on the shores of Lake Michigan. It is one of the 10 largest pumped-storage power plants in the world.

Last Updated: October 17, 2024

- [Consumption by Source](#)
- [Consumption by Sector](#)
- [Production](#)
- [Electricity](#)
- [Prices](#)

## Data

Last Update: May 15, 2025 | Next Update: June 20, 2025

### Energy Indicators

Demography	Michigan	Share of U.S.	Period
Population	10.1 million	3.0%	2024
Civilian Labor Force	5.1 million	3.0%	Mar-25
Economy	Michigan	U.S. Rank	Period
Gross Domestic Product	\$ 659.0 billion	14	2023
Gross Domestic Product for the Manufacturing Sector	\$ 107,736 million	7	2023
Per Capita Personal Income	\$ 59,714	40	2023
Vehicle Miles Traveled	98,289 million miles	10	2023
Land in Farms	9.4 million acres	30	2024
Climate	Michigan	U.S. Rank	Period
Average Temperature	48.9 degrees Fahrenheit	37	2024
Precipitation	34.4 inches	35	2024

### Prices

Petroleum	Michigan	U.S. Average	Period	<a href="#">find more</a>
<a href="#">Domestic Crude Oil First Purchase</a>	\$ 64.24 /barrel	\$ 70.11 /barrel	Feb-25	
Natural Gas	Michigan	U.S. Average	Period	<a href="#">find more</a>
<a href="#">City Gate</a>	\$ 4.00 /thousand cu ft	\$ 4.83 /thousand cu ft	Feb-25	<a href="#">find more</a>
<a href="#">Residential</a>	\$ 9.55 /thousand cu ft	\$ 12.94 /thousand cu ft	Feb-25	<a href="#">find more</a>
Coal	Michigan	U.S. Average	Period	<a href="#">find more</a>
<a href="#">Average Sales Price</a>	--	\$ 54.04 /short ton	2023	
<a href="#">Delivered to Electric Power Sector</a>	W	\$ 2.41 /million Btu	Feb-25	
Electricity	Michigan	U.S. Average	Period	<a href="#">find more</a>
<a href="#">Residential</a>	18.91 cents/kWh	16.44 cents/kWh	Feb-25	<a href="#">find more</a>
<a href="#">Commercial</a>	14.05 cents/kWh	13.09 cents/kWh	Feb-25	<a href="#">find more</a>
<a href="#">Industrial</a>	8.54 cents/kWh	8.23 cents/kWh	Feb-25	<a href="#">find more</a>

**Reserves**

<b>Reserves</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	<a href="#">find more</a>
Crude Oil (as of Dec. 31)	46 million barrels	0.1%	2022	<a href="#">find more</a>
Expected Future Production of Dry Natural Gas (as of Dec. 31)	1,302 billion cu ft	0.2%	2022	<a href="#">find more</a>
Expected Future Production of Natural Gas Plant Liquids	11 million barrels	*	2022	<a href="#">find more</a>
Recoverable Coal at Producing Mines	--	--	2023	<a href="#">find more</a>
<b>Rotary Rigs &amp; Wells</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	<a href="#">find more</a>
Natural Gas Producing Wells	1,308 wells	0.3%	2020	<a href="#">find more</a>
<b>Capacity</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	
Crude Oil Refinery Capacity (as of Jan. 1)	140,000 barrels/calendar day	0.8%	2024	
Electric Power Industry Net Summer Capacity	31,538 MW	2.6%	Feb-25	

**Supply & Distribution**

<b>Production</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	<a href="#">find more</a>
Total Energy	562 trillion Btu	0.6%	2022	<a href="#">find more</a>
Crude Oil	11 thousand barrels per day	0.1%	Feb-25	<a href="#">find more</a>
Natural Gas - Marketed	68,132 million cu ft	0.2%	2023	<a href="#">find more</a>
Coal	--	--	2023	<a href="#">find more</a>
<b>Total Utility-Scale Net Electricity Generation</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	<a href="#">find more</a>
Total Net Electricity Generation	10,281 thousand MWh	3.0%	Feb-25	
<b>Utility-Scale Net Electricity Generation (share of total)</b>	<b>Michigan</b>	<b>U.S. Average</b>	<b>Period</b>	
Petroleum-Fired	0.1 %	0.4 %	Feb-25	<a href="#">find more</a>
Natural Gas-Fired	35.6 %	39.0 %	Feb-25	<a href="#">find more</a>
Coal-Fired	27.5 %	18.4 %	Feb-25	<a href="#">find more</a>
Nuclear	22.6 %	18.2 %	Feb-25	<a href="#">find more</a>
Renewables	12.4 %	23.6 %	Feb-25	

**Supply & Distribution**

<b>Stocks</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	<a href="#">find more</a>
<a href="#">Motor Gasoline (Excludes Pipelines)</a>	9 thousand barrels	0.1%	Feb-25	
<a href="#">Distillate Fuel Oil (Excludes Pipelines)</a>	1,641 thousand barrels	1.8%	Feb-25	<a href="#">find more</a>
<a href="#">Natural Gas in Underground Storage</a>	599,933 million cu ft	9.6%	Feb-25	<a href="#">find more</a>
<a href="#">Petroleum Stocks at Electric Power Producers</a>	157 thousand barrels	0.8%	Feb-25	<a href="#">find more</a>
<a href="#">Coal Stocks at Electric Power Producers</a>	2,054 thousand tons	1.9%	Feb-25	<a href="#">find more</a>
<b>Fueling Stations</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	
Motor Gasoline	3,539 stations	3.2%	2022	
Propane	87 stations	3.3%	Apr-25	
Electric Vehicle Charging Locations	1,606 stations	2.3%	Apr-25	
E85	247 stations	5.6%	Apr-25	
Biodiesel, Compressed Natural Gas, and Other Alternative Fuels	9 stations	0.2%	Apr-25	

**Consumption & Expenditures**

<b>Summary</b>	<b>Michigan</b>	<b>U.S. Rank</b>	<b>Period</b>	
<a href="#">Total Consumption</a>	2,707 trillion Btu	10	2022	<a href="#">find more</a>
<a href="#">Total Consumption per Capita</a>	270 million Btu	28	2022	<a href="#">find more</a>
<a href="#">Total Expenditures</a>	\$ 46,032 million	9	2022	<a href="#">find more</a>
<a href="#">Total Expenditures per Capita</a>	\$ 4,588	41	2022	<a href="#">find more</a>
<b>by End-Use Sector</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	
Consumption				
» <a href="#">Residential</a>	754 trillion Btu	3.9%	2022	<a href="#">find more</a>
» <a href="#">Commercial</a>	579 trillion Btu	3.5%	2022	<a href="#">find more</a>
» <a href="#">Industrial</a>	664 trillion Btu	2.1%	2022	<a href="#">find more</a>
» <a href="#">Transportation</a>	711 trillion Btu	2.6%	2022	<a href="#">find more</a>
Expenditures				
» <a href="#">Residential</a>	\$ 11,064 million	3.3%	2022	<a href="#">find more</a>

**Consumption & Expenditures**

» Commercial	\$ 7,148 million	2.9%	2022	<a href="#">find more</a>
» Industrial	\$ 6,267 million	2.2%	2022	<a href="#">find more</a>
» Transportation	\$ 21,553 million	2.5%	2022	<a href="#">find more</a>
<b>by Source</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	
Consumption				
» Petroleum	163 million barrels	2.2%	2023	<a href="#">find more</a>
» Natural Gas	1,048 billion cu ft	3.2%	2023	<a href="#">find more</a>
» Coal	14,516 thousand short tons	3.4%	2023	<a href="#">find more</a>
Expenditures				
» Petroleum	\$ 21,905 million	2.4%	2023	<a href="#">find more</a>
» Natural Gas	\$ 7,382 million	3.7%	2023	<a href="#">find more</a>
» Coal	\$ 979 million	4.1%	2023	<a href="#">find more</a>
<b>Consumption for Electricity Generation</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	<a href="#">find more</a>
Petroleum	13 thousand barrels	0.6%	Feb-25	<a href="#">find more</a>
Natural Gas	25,619 million cu ft	2.7%	Feb-25	<a href="#">find more</a>
Coal	1,558 thousand tons	4.4%	Feb-25	<a href="#">find more</a>
<b>Energy Source Used for Home Heating (share of households)</b>	<b>Michigan</b>	<b>U.S. Average</b>	<b>Period</b>	
Natural Gas	74.0 %	46.0 %	2023	
Fuel Oil	0.8 %	3.7 %	2023	
Electricity	12.7 %	41.7 %	2023	
Propane	9.1 %	5.0 %	2023	
Other/None	3.4 %	3.5 %	2023	

**Environment**

<b>Renewable Energy Capacity</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	<a href="#">find more</a>
Total Renewable Energy Electricity Net Summer Capacity	5,826 MW	1.6%	Feb-25	
Ethanol Plant Nameplate Capacity	346 million gal/year	1.9%	2024	
<b>Renewable Energy Production</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	<a href="#">find more</a>

**Environment**

Utility-Scale Hydroelectric Net Electricity Generation	101 thousand MWh	0.5%	Feb-25	
Utility-Scale Solar, Wind, and Geothermal Net Electricity Generation	1,004 thousand MWh	1.8%	Feb-25	
Utility-Scale Biomass Net Electricity Generation	169 thousand MWh	4.6%	Feb-25	
Small-Scale Solar Photovoltaic Generation	23 thousand MWh	0.4%	Feb-25	
Fuel Ethanol Production	7,903 thousand barrels	2.2%	2022	
<b>Renewable Energy Consumption</b>	<b>Michigan</b>	<b>U.S. Rank</b>	<b>Period</b>	<a href="#">find more</a>
Renewable Energy Consumption as a Share of State Total	7.4 %	28	2022	
Fuel Ethanol Consumption	10,287 thousand barrels	9	2022	
<b>Total Emissions</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	<a href="#">find more</a>
Carbon Dioxide	154.0 million metric tons	3.1%	2022	
<b>Electric Power Industry Emissions</b>	<b>Michigan</b>	<b>Share of U.S.</b>	<b>Period</b>	<a href="#">find more</a>
Carbon Dioxide	50,018 thousand metric tons	3.3%	2023	
Sulfur Dioxide	31 thousand metric tons	3.7%	2023	
Nitrogen Oxide	43 thousand metric tons	3.8%	2023	

## Analysis

Last Updated: October 17, 2024

## Overview

Known as the Great Lakes State, Michigan's shores touch and include portions of four of the five Great Lakes.<sup>1</sup> The northern ends of two Great Lakes—Lake Michigan and Lake Huron—divide Michigan into the Upper and Lower Peninsulas. The northern shore of the Upper Peninsula is bordered by Lake Superior and a small portion of the southeastern shore of the Lower Peninsula touches Lake Erie.<sup>2,3</sup> The state's geologic history includes ancient broad shallow seas in a basin that was centered in Michigan's Lower Peninsula.<sup>4</sup> That basin was ringed by reefs that, now deeply buried, contain most of the state's crude oil and natural gas reserves.<sup>5</sup> In addition to Michigan's natural gas and crude oil, the state has many renewable energy resources. Winds that sweep across the Great Lakes provide the state with substantial offshore wind energy resources and moderate onshore ones.<sup>6</sup> Forests cover more than half of the state's land area and many cities and large towns provide municipal solid waste and landfill gas, giving Michigan considerable biomass resources.<sup>7,8</sup> Dams on the state's rivers generate hydroelectric power, despite the generally level terrain.<sup>9</sup> Most of those dams, including all of the largest ones, are in the Lower Peninsula, where Michigan's largest and longest rivers are located.<sup>10,11</sup>

Most of Michigan's population and all of the major cities, manufacturing industries, commercial agriculture, crude oil production, and natural gas production are located in the state's Lower Peninsula.<sup>12,13</sup> The Upper Peninsula is lightly populated, heavily forested, and contains valuable iron and copper deposits.<sup>14,15,16</sup> With 40,000 square miles of the Great Lakes and thousands of smaller inland lakes and ponds within Michigan's borders, the state's total area is more than two-fifths water—the largest land-to-water ratio among all states.<sup>17,18</sup> As a result, Michigan has one of the longest shorelines in the United States. Vessels that move through the Great Lakes-Saint Lawrence Seaway deliver coal and refined petroleum products at several of the state's Great Lakes ports.<sup>19,20,21</sup>

Michigan consumes almost five times more energy than it produces and ranks 10th among the states in both population and total energy consumption.<sup>22,23,24</sup> Although the Great Lakes moderate Michigan's temperatures, extremes occur in the interior of the Lower Peninsula. However, snowfalls are greatest on the Upper Peninsula and along the Lake Michigan shoreline of the Lower Peninsula.<sup>25</sup> In part because of its cold winters, Michigan is among the top 10 states in per capita residential energy use, but the state's total energy use per capita is below the U.S. average.<sup>26</sup> The residential sector is the leading energy-consuming sector, accounting for 28% of the state's total energy use, followed closely by the transportation sector at 26%, the industrial sector at 25%, and the commercial sector at 21%.<sup>27</sup> Detroit is known as Motor City, and Michigan employs the largest number of workers in the motor vehicles and parts manufacturing sectors in the nation.<sup>28,29</sup> This sector accounts for nearly two-fifths of the state's manufacturing GDP. Other important contributors to the state's GDP include the manufacture of machinery, fabricated metal products, chemicals, food and beverage products, and plastics.<sup>30</sup> Michigan does not have any significant critical mineral deposits, but is a major producer of cement, construction sand, and gravel.<sup>31</sup>

*Michigan ranks 10th among the states in total energy use.*

## Natural gas

The Antrim Shale formation sweeps along a narrow arc in the northern portion of the Lower Peninsula and contains most of Michigan's natural gas reserves, and the state holds about 0.2% of U.S. total proved reserves.<sup>32,33,34</sup> Michigan's natural gas production has declined from its 1997 peak of nearly 312 billion cubic feet to 68 billion cubic feet in 2023, making up 0.2% of total U.S. production.<sup>35,36</sup>

Several interstate pipelines cross Michigan, as well as five U.S.-Canadian natural gas pipeline border crossings, but the state does not have any natural gas market hubs.<sup>37</sup> Natural gas enters Michigan from Ohio, Wisconsin, and Indiana. While some natural gas also arrives by pipeline from Canada, the bulk of the natural gas flowing across the border goes to Canada, most of it at St. Clair, located northeast of Detroit. Smaller volumes of natural gas also intermittently enter Canada at the Detroit, Sault St. Marie, and Marysville border crossings.<sup>38,39,40</sup> More natural gas enters Michigan than is consumed in the state, and most of the excess is exported to Canada.<sup>41,42</sup>

Some of the natural gas that Michigan receives or produces is injected into underground natural gas storage fields. Michigan has the largest underground natural gas storage capacity in the nation at nearly 1.1 trillion cubic feet, which is almost one-eighth of the U.S. total. The state has 44 natural gas storage fields, the second-largest number after Pennsylvania.<sup>43,44</sup> During high demand periods, typically between November and April, natural gas is withdrawn from storage to meet increased demand for space heating. Much smaller volumes of natural gas are withdrawn from storage in the summer months when natural gas-fueled power generation increases to meet cooling demand.<sup>45,46</sup>

*Michigan has the largest underground natural gas storage capacity in the nation.*

In 2023, Michigan's total natural gas consumption was 15 times greater than the state's natural gas production.<sup>47,48</sup> The electric power sector became the largest consumer of natural gas in the state in 2023, surpassing the residential sector for the first time and making up two-fifths of total natural gas use. The residential

sector, where almost 8 out of 10 Michigan households use natural gas as their primary source for home heating, accounted for about three-tenths of the state's natural gas consumption.<sup>49,50</sup> Michigan routinely ranks among the top 5 states in residential use of natural gas and in the top 10 for total natural gas consumption.<sup>51,52</sup> The commercial and the industrial sectors each account for about 16% of the state's natural gas consumption.<sup>53</sup>

## Petroleum

Michigan's crude oil reserves and production are modest. The state's crude oil reserves and production each account for 0.1% of the nation's total.<sup>54,55</sup> Commercial quantities of crude oil were first found in Michigan in 1925.<sup>56</sup> The state's oil production substantially increased in the 1970s when oil was produced from the deeply buried reefs that ringed the Michigan Basin millions of years ago. Those reefs accounted for 29 million of the 35 million barrels of crude oil recovered in Michigan's peak production year of 1979.<sup>57,58,59</sup> Since then, Michigan's crude oil output has generally declined and was about 4.8 million barrels in 2023.<sup>60</sup>

Michigan has one crude oil refinery, located near Detroit. It can process about 140,000 barrels per calendar day of light sweet and heavy sour crude oils into gasoline, asphalt, propane, and other petroleum products.<sup>61,62</sup> Crude oil produced from wells in western Canada enters Michigan by pipelines through Wisconsin and Indiana. Crude oil produced in western Michigan is delivered by an intrastate pipeline to Lewiston, Michigan, where it is added into the Enbridge pipeline system that enters the state through northern Wisconsin. The Enbridge pipeline delivers crude oil to a Canadian refinery in Ontario and also has a branch that enters the state from Indiana and delivers crude oil to Michigan on its way to Ontario.<sup>63,64,65</sup> Michigan's governor revoked the pipeline's permit in May 2021 because of safety concerns about a potential leak where an underwater section of the pipeline crosses the Mackinac Strait between the state's Upper and Lower Peninsulas. Enbridge has refused to shut down the pipeline and the legal dispute remains. There have been discussions around building a tunnel to house the pipeline.<sup>66,67,68</sup> The Mid-Valley Pipeline, another crude oil pipeline that originates in the U.S. Gulf Coast states, enters Michigan through Ohio.<sup>69</sup> Port Huron on the Lower Peninsula receives additional crude oil imports from Canada.<sup>70</sup> Much of the crude oil that enters Michigan exits into Canada at a border crossing between Marysville, Michigan, and Sarnia, Ontario.<sup>71</sup>

Petroleum product pipelines bring refined products from the Chicago, Illinois, area to the southwest and from the Toledo, Ohio, area to the southeast of Michigan in the Lower Peninsula. The Upper Peninsula has no petroleum product pipelines, and trucks transport most petroleum products from terminals in Wisconsin.<sup>72,73</sup> The Lower Peninsula port cities of Port Huron and Detroit receive almost all the state's petroleum product imports from Canada. Some Canadian petroleum products also arrive at the Sault St. Marie port on the Upper Peninsula.<sup>74</sup>

Michigan ranks 11th among the states in total petroleum consumption. Four-fifths of the state's petroleum use is in the transportation sector, and motor gasoline accounts for 62% of that transportation petroleum consumption.<sup>75,76</sup> Federal regulations allow conventional motor gasoline without ethanol to be sold in most of the state year-round. However, to reduce emissions that contribute to ground-level ozone, eight southeastern Michigan counties around Detroit regulate the vapor pressure of motor gasoline sold during the summer.<sup>77,78</sup> The industrial sector accounts for one-tenth of the state's petroleum use. Although the residential sector accounts for only about 6% of the state's petroleum consumption, Michigan is among the top five states in residential sector petroleum consumption.<sup>79</sup> About 1 in 10 Michigan households heat with petroleum products, mostly propane.<sup>80,81</sup> Total consumption of hydrocarbon gas liquids (HGLs), such as propane, is greater in Michigan than in all but seven other states, and the state has the largest residential sector HGL consumption in the nation.<sup>82</sup> The commercial sector accounts for most of the rest of the state's petroleum consumption. A small amount of petroleum is used intermittently for electricity generation.<sup>83</sup>

*Michigan has the largest residential sector consumption of hydrocarbon gas liquids, such as propane, in the nation.*

## Electricity

In 2023, natural gas fueled the largest share of Michigan's electricity generation at 46%, followed by nuclear power at 23%, and coal at 19%. Up until 2020, coal had provided the largest share of the state's electricity net generation.<sup>84</sup> Coal-fired plants make up 3 of the 10 largest power plants by generating capacity in the state, including the largest, and 4 of the top 10 were natural-gas fired.<sup>85</sup> Since 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned. The state's most recent operating coal-fired generating unit came online in 1990.<sup>86</sup> Michigan's electricity net generation from natural gas is more than four times greater in the last decade.<sup>87</sup> Two new natural gas-fired power plants are expected to come online by 2025, adding 1,000 megawatts of generating capacity.<sup>88</sup>

Typically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned. The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022.<sup>89,90,91</sup> However, the new owners of the Palisades nuclear power plant are seeking to restart the plant.<sup>92</sup> The state currently has two operating nuclear power plants, Fermi with one reactor and Donald C. Cook with two reactors.<sup>93</sup>

Wind energy accounts for a small but increasing share of Michigan's electricity generation and accounted for 7% of the state's total generation in 2023. This was a slight decline from 2022, due to below normal wind speeds, despite 337 megawatts of new wind power generating capacity that came online in 2023.<sup>94,95,96</sup> Biomass, solar energy, gases created as byproducts of industrial processes, petroleum coke, and hydroelectric power provided most of the rest of the state's net generation.<sup>97</sup> Most of Michigan's power plants are located in the Lower Peninsula, where electricity demand is greatest.<sup>98</sup>

In 2023, Michigan ranked 11th among the states in the amount of electricity generated. Because consumption was less than generation, Michigan sent its surplus electricity out of state via the regional grid.<sup>99,100</sup> The commercial sector is the state's largest electricity consumer, accounting for 37% of the state's total electricity sales, followed very closely by the residential sector, with 34%. The industrial sector accounts for 29% of power sales.<sup>101</sup> Residential electricity sales per capita are less than in three-fourths of the states and less than the national average.<sup>102,103</sup> Only about 1 in 8 Michigan households rely on electricity as their primary source of energy for home heating.<sup>104</sup>

In July 2024, Michigan had about 1,500 public electric vehicle charging locations.<sup>105</sup> The majority of charging stations are located on the Lower Peninsula around Detroit, Grand Rapids, Lansing, and Kalamazoo.<sup>106</sup> The Charge Up Michigan Program provides grants to private and public organizations to help expand the state's electric vehicle charging network.<sup>107</sup>

## Renewable energy

Renewable energy provided 11% of Michigan's total in-state electricity net generation in 2023, most of it from wind. In 2013, wind energy surpassed hydropower and biomass and became Michigan's largest source for renewable generation. In 2023, wind energy supplied 64% of the state's renewable electricity and about 7% of Michigan's total net generation from all sources.<sup>108</sup> The state's strongest onshore winds are along its curving Lake Huron and Lake Michigan coastlines.<sup>109,110</sup> Michigan ranks 12th in the nation in wind generation capacity and 16th in actual generation from wind energy.<sup>111</sup> The state has 34 wind farms with a total generating capacity of nearly 3,800 megawatts.<sup>112</sup> Many of

*Michigan's in-state electricity net generation from natural gas is more than four times greater in the last decade.*

*Electricity net generation from utility-scale solar in Michigan increased by 53% in 2023.*

Michigan's wind farms are located between Saginaw Bay and Lake Huron in the eastern part of the state's Lower Peninsula.<sup>113</sup>

In 2023, biomass provided 15% of Michigan's renewable electricity generation and about 2% of the state's total generation from all sources.<sup>114</sup> Michigan has 35 biomass power plants with a combined generating capacity of 490 megawatts. A municipal solid waste plant in the Detroit area is one of the largest on the Lower Peninsula. The biomass plants that are fueled with wood and wood waste are primarily in more heavily forested northern Michigan, including on the Upper Peninsula. Several biomass facilities generate electricity using methane recovered from landfills.<sup>115,116</sup> Additionally, the state has anaerobic digesters that convert animal and food waste into biogas (methane) that is used as fuel for electricity generation.<sup>117,118,119</sup> Michigan's forests also provide the feedstock for the state's three wood pellet manufacturing plants that have a combined production capacity of 173,000 tons of pellets per year.<sup>120</sup> Wood pellets are used as fuel for electricity generation and for space heating. Wood is used for space heating by 2% of households in Michigan.<sup>121</sup>

Michigan has about four dozen conventional hydroelectric dams that accounted for about 1% of the state's total generation from all sources in 2023. However, the state's largest hydroelectric facility by capacity is a pumped-storage plant on the shores of Lake Michigan on the Lower Peninsula.<sup>122,123,124</sup> Built in 1973, Michigan's Ludington pumped storage plant has a nameplate generating capacity of about 2,200 megawatts and is one of the ten largest pumped storage power plants in the world.<sup>125,126</sup> During periods of low power demand, which are usually at night, less costly electricity is used to pump water from a lower reservoir to an upper reservoir. Then, during periods when power demand and electricity prices are higher, the water is released from the upper reservoir and flows down through generating turbines on its way back to the lower reservoir, producing electricity. Although the plant uses more power than it generates, it supplies power in periods of peak demand when electricity prices are highest.<sup>127</sup>

Michigan produces and consumes biofuels. It has four fuel ethanol production plants, all located in the southern half of the Lower Peninsula.<sup>128</sup> Those plants have a combined capacity of about 350 million gallons each year and produced 330 million gallons of fuel ethanol in 2022.<sup>129,130</sup> Michigan is among the nation's top 10 fuel ethanol-consuming states and uses more than it produces. In 2022, the state consumed about 430 million gallons of fuel ethanol.<sup>131</sup> Michigan's two biodiesel plants are also located on the Lower Peninsula.<sup>132</sup> These plants can produce 16 million gallons of biodiesel fuel each year, less than the 28 million gallons consumed in the state annually.<sup>133,134</sup>

In 2023, utility-scale (1 megawatt or larger) solar installations generated 1% of Michigan's total in-state electricity. The state's first utility-scale solar power facility, the 1-megawatt Domino Farms Solar, came online in 2015. In 2023, electricity net generation from utility-scale solar in Michigan increased by 53%.<sup>135</sup> Eleven solar farms came online in 2023, adding nearly 270 megawatts of generation capacity, including the 100-megawatt Cereal City Solar Energy Center project. An additional 1,280 megawatts of solar power capacity are expected to be added in the state by 2025.<sup>136,137</sup> Customer-sited, small-scale (less than 1 megawatt) solar photovoltaic (PV) generating systems, most of which are on residential and business rooftops, provided 19% of the state's total solar power.<sup>138</sup>

Michigan enacted a renewable energy standard (RES) in 2008 that required the state's retail electricity providers, including investor-owned electric utilities, alternative retail suppliers, electric cooperatives, and municipal electric utilities, to have at least 10% of the electricity they sold be generated by renewable energy resources by 2015. The RES goal was met, and, in December 2016, the state's RES requirement increased to 15% of electricity sales by 2021.<sup>139</sup> In 2020, all of Michigan's electric providers met the 15% RES.<sup>140</sup> Acceptable renewable energy resources for generating electricity include solar power, biomass, wind, geothermal energy, municipal solid waste, landfill gas, existing hydroelectricity, and tidal, wave, and river currents. Utilities are allowed to use energy efficiency to meet a portion of their requirements. In 2023, Michigan expanded the RES requirements, with an aim to use 100% clean energy by 2040.<sup>141</sup>

## Coal

Michigan has a small amount of economically recoverable coal reserves, but no active coal mines.<sup>142</sup> However, Michigan ports, including the Port of Detroit, handled 31% of all Great Lakes coal shipments in 2023.<sup>143</sup> The electric power sector uses 92% of the coal consumed in Michigan to generate electricity. The industrial and commercial sectors use the other 8% to produce coke for steelmaking and for electricity and heat.<sup>144</sup> Most of the coal consumed in Michigan comes by rail from the West, primarily from Wyoming and Montana. Small amounts of coal also arrive from nearby states, including West Virginia, Pennsylvania, Colorado, Kentucky, Virginia, Indiana, and Illinois.<sup>145</sup>

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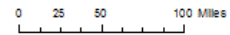
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States:Electricity Transmission Lines - Ventyx, Velocity Suite;Grey Base:National



- |                          |                                  |                               |
|--------------------------|----------------------------------|-------------------------------|
| ■ Mask                   | ⊕ Hydroelectric Power Plant      | Ⓜ Pumped Storage Power Plant  |
| ▲ Surface Coal Mine      | ⊕ Natural Gas Power Plant        | ☀ Solar Power Plant           |
| ▼ Underground Coal Mine  | ⊕ Nuclear Power Plant            | ⊕ Wind Power Plant            |
| ⊕ Biomass Power Plant    | ● Other Power Plant              | ⊕ Wood Power Plant            |
| ⊕ Coal Power Plant       | ⊕ Other Fossil Gases Power Plant | ⊕ Petroleum Refinery          |
| ⊕ Geothermal Power Plant | ⊕ Petroleum Power Plant          | ⊕ Strategic Petroleum Reserve |

<http://www.eia.gov/state/>

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) )  
Emergency Order: Midcontinent )  
Independent System Operator )  
(MISO) )  
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Order No. 202-26-16

Exhibit to  
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# Exhibit 53

## Consumers News Release



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A key regulatory decision today cleared the way for Consumers Energy to stop burning coal to generate electricity by 2025 — 15 years faster than previously planned — and provide reliable electricity for Michigan.

The Michigan Public Service Commission (MPSC) approved Consumers Energy's agreement with a diverse group of stakeholders on updates to its Clean Energy Plan, a 20-year blueprint to meet Michigan's energy needs while protecting the environment for future generations.

A broad coalition of supporters for the plan includes customer groups, environmental organizations, MPSC staff, energy industry representatives and the Michigan Attorney General.

Consumers Energy is one of the first utilities in the nation to go coal-free.

"This is a historic moment in Michigan's clean energy transformation journey," said Garrick Rochow, President and CEO of Consumers Energy. "The Clean Energy Plan is a sea change that positions our company as a national leader and empowers us to deliver reliable energy while protecting the planet for decades to come."

The updates to Consumers Energy's Clean Energy Plan — first approved in 2019 — include:

- **COAL PLANT RETIREMENTS BY 2025:** closes all three units at the J.H. Campbell coal plant in West Olive in 2025 in addition to two units at the D.E. Karn coal plant in 2023 (as per the 2018 Clean Energy Plan) and will be among the first utilities in the nation to go coal-free by 2025.
- **SYSTEM RELIABILITY:** ensures supply reliability through the purchase of the Covert Generating Station in Van Buren County, a natural gas-fired power plant. Additionally, we plan to purchase 700 megawatts of electric capacity — roughly the equivalent of a power plant — from a variety of sources through a one-time request for proposal (RFP).
- **RISE OF SOLAR:** continues the rapid transition to clean, renewable sources by adding nearly 8,000 megawatts (MW) of solar power by 2040 ensuring 90 percent of our capacity comes from clean sources. Learn more at [ConsumersEnergy.com/MiSolar](https://www.consumersenergy.com/MiSolar) (<https://www.consumersenergy.com/company/electric-generation/renewables/solar-generation/farmers>).
- **BATTERY DEPLOYMENT:** accelerates energy storage with a total of 75 MW of energy storage by 2027, achieving 550 MW by 2040.
- **AFFORDABLE ENERGY:** creates price stability and helps customers save an estimated \$600 million dollars through 2040 compared to the current plan. Consumers Energy would also continue its successful energy waste reduction programs that have saved customers nearly \$5 billion since 2009. In addition, the company has committed to continue to fund utility bill assistance programs for low-income customers.

"Together, we've created the best Clean Energy Plan for Michigan," Rochow said. "We're building a dramatically different energy landscape in which customers won't have to choose between protecting the planet and their pocketbooks. We will do both while making sure our state has the reliable power it needs."

Consumers Energy, Michigan's largest energy provider, is the principal subsidiary of CMS Energy (NYSE: CMS), providing natural gas and/or electricity to 6.8 million of the state's 10 million residents in all 68 Lower Peninsula counties.

###

Media Contacts: Katie Carey, 517-740-1739, or Brian Wheeler, 517-740-1545

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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# Exhibit 54

# NARUC Coal Report



# Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices

National Association of Regulatory Utility Commissioners | January 2020

*Phillip Graeter, Energy Ventures Analysis, Inc.*

*Seth Schwartz, Energy Ventures Analysis, Inc.*



**EXHIBIT 15: TYPICAL STARTUP AND CYCLING COSTS FOR A  
MEDIUM-SIZED COAL-FIRED POWER PLANT (\$2019)<sup>19</sup>**

Type of Start	Cost category	Cost estimates (\$/MW)		
		Expected	Low	High
<b>Hot Start (1–23 h offline)</b>	Maintenance and capital	\$ 128	\$ 102	\$ 162
	Forced outage	\$ 60	\$ 48	\$ 76
	Start-up fuel	\$ 20	\$ 14	\$ 30
	Auxiliary power	\$ 11	\$ 8	\$ 13
	Efficiency loss from low and variable load operation	\$ 5	\$ 4	\$ 8
	Water chemistry cost and support	\$ 1	\$ 1	\$ 2
	<b>Total cycling cost</b>	<b>\$ 225</b>	<b>\$ 178</b>	<b>\$ 291</b>
<b>Warm Start (24 - 120 h offline)</b>	Maintenance and capital	\$ 137	\$ 109	\$ 170
	Forced outage	\$ 65	\$ 51	\$ 80
	Start-up fuel	\$ 43	\$ 30	\$ 57
	Auxiliary power	\$ 23	\$ 18	\$ 28
	Efficiency loss from low and variable load operation	\$ 6	\$ 5	\$ 9
	Water chemistry cost and support	\$ 6	\$ 4	\$ 9
<b>Total cycling cost</b>	<b>\$ 277</b>	<b>\$ 217</b>	<b>\$ 351</b>	
<b>Cold Start (&gt; 120 h offline)</b>	Maintenance and capital	\$ 205	\$ 162	\$ 255
	Forced outage	\$ 96	\$ 76	\$ 120
	Start-up fuel	\$ 64	\$ 45	\$ 24
	Auxiliary power	\$ 29	\$ 23	\$ 36
	Efficiency loss from low and variable load operation	\$ 6	\$ 5	\$ 10
	Water chemistry cost and support	\$ 17	\$ 13	\$ 21
<b>Total cycling cost</b>	<b>\$ 417</b>	<b>\$ 325</b>	<b>\$ 465</b>	
<b>Load follow down to 36% of Capacity</b>	Maintenance and capital	\$ 20	\$ 12	\$ 31
	Forced outage	\$ 9	\$ 6	\$ 15
	Efficiency loss from low and variable load operation	\$ 1	\$ 1	\$ 2
	Mill cycle gas	\$ 2	\$ 19	\$ 50
	<b>Total cycling cost</b>	<b>\$ 32</b>	<b>\$ 19</b>	<b>\$ 50</b>

As shown in **Exhibit 15**, expected costs for cold starts can be almost double the startup cost for a hot start when the remaining temperature in the boiler and turbine system are still significantly higher. However, even hot starts can range from \$89,000 to \$145,500 per start for a 500 MW coal-fired EGU. These costs can also vary significantly between coal units based on differences in boiler size and design (subcritical vs. supercritical). The highest cost

<sup>19</sup> Source: Lefton S A, Hilleman D (2011). *Make your plant ready for cycling operations*.  
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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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# Exhibit 55

# IEA Flexibility Report

# Increasing the flexibility of coal-fired power plants

Colin Henderson

September 2014

© IEA Clean Coal Centre

## 4 Increasing flexibility – turbine and water-steam systems

There is much that can be done to make these areas of a plant more durable, able to respond faster and suffer less efficiency losses. Examples are given in this chapter.

### 4.1 Reducing stresses during start-up

Start-up, especially from cold, places particularly large stresses on many parts of a coal-fired plant. The turbine is no exception in this regard. Very rapid temperature changes need to be kept to the minimum, while component designs can be adapted to suit. Lindsay and Dragoon (2010) have collected together data from published sources on start-up times for different plant conditions. They found that, generally, coal plants required approximately 12 hours to cold start, 4 hours to warm start, and 1 hour to hot start. There was considerable variation, and this was believed to stem from how hot, warm, and cold starts were defined, and whether those times were actually equipment-limited or not.

One of the requirements for flexibility in the turbine is that the very small clearances between stationary and moving components remain almost constant during output changes. This requires careful design, advanced sealing (*see also* Henderson, 2013) and measures for ensuring uniform thermal loading and applies especially during cold start-up operations (Quinkertz and others, 2008).

Turbine bypass systems are a necessity in plants designed for two-shift (on/off) and other flexible forms of operation. They allow all or part of the steam to bypass the HP turbine or LP turbine so that the rate of steam temperature change in the turbine can be managed as the boiler is starting up and shutting down. This allows thermal stresses in the turbine to be reduced (Lindsay and Dragoon, 2010). This is not to be confused with another type of bypass (HP stage bypass), that can be installed for frequency control in new plants and is described later.

The very high temperature and pressure conditions of USC systems necessitate use of thick-walled components so that they possess adequate strength. Unfortunately, this can limit the rate of temperature change consistent with reducing thermal fatigue to acceptable levels. In the turbine, one means used to counter this is steam cooling of the outer casing to keep its temperature 30–40°C lower than that of the inner casing at the corresponding position along the turbine during load changes. The steam for this is bled radially from points along the inner casing. The steam reduces temperature extremes in the outer casing and allows its thickness to be reduced. The result is that cold start-up time is reduced by almost 50% (Almstedt and others, 2007).

### 4.2 Load following using sliding pressure operation

While, traditionally, throttling has been used to vary output from a turbine while keeping the pressure constant (Lindsay and Dragoon, 2010), sliding pressure operation has become a commonly applied system in modern supercritical once-through systems (Henderson, 2004). A critical constraint on ramping operation is matching steam and turbine metal temperatures, and more rapid output changes can be achieved using sliding pressure. Sliding pressure also offers advantages over throttle control

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Exhibit 56  
Blumenstock 2021 Second  
Rebuttal Testimony

## 1 STATE OF MICHIGAN

## 2 BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

3 In the matter of the application of  
CONSUMERS ENERGY COMPANY for Case No. U-21090  
4 approval of an Integrated Resource  
Plan under MCL 460.6t, certain Volume 10  
5 accounting approvals, and other relief.

6 \_\_\_\_\_/  
7 CROSS-EXAMINATION (Settlement Agreement)

8 Proceedings held via Microsoft Teams in the  
9 above-entitled matter before Sally L. Wallace,  
10 Administrative Law Judge with MOAHR, for the Michigan  
11 Public Service Commission, Lansing, Michigan, on  
12 Friday, May 20, 2022, at 9:06 a.m.

## 13 APPEARANCES:

14 ROBERT W. BEACH, ESQ.  
BRET A. TOTORAITIS, ESQ.  
15 MICHAEL C. RAMPE, ESQ.  
Consumers Energy Company  
16 One Energy Plaza, Room EP11-223  
Jackson, Michigan 49201

17 On behalf of Consumers Energy Company

18 THOMAS J. WATERS, ESQ.  
19 The Running Wise Law Firm  
1501 Cass Street, Suite D  
20 P. O. Box 686  
Traverse City, Michigan 49685

21 On behalf of Biomass Merchant Plants (BMPs)

22 CELESTE R. GILL, Asst. Attorney General  
23 525 W. Ottawa Street, 7th floor  
P.O. Box 30755  
24 Lansing, Michigan 48909

25 On behalf of Michigan Attorney General

(Continued)

Metro Court Reporters Inc. metrostate@sbcglobal.net

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of )  
**CONSUMERS ENERGY COMPANY** )  
for Approval of an Integrated Resource Plan )  
under MCL 460.6t, certain accounting )  
approvals, and for other relief. )  
\_\_\_\_\_ )

Case No. U-21090

**SECOND REBUTTAL TESTIMONY**  
**OF**  
**RICHARD T. BLUMENSTOCK**  
**ON BEHALF OF**  
**CONSUMERS ENERGY COMPANY**

May 2022

RICHARD T. BLUMENSTOCK  
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1 **Q. Please state your name and business address.**

2 A. My name is Richard T. Blumenstock, and my business address is 1945 West Parnall Road,  
3 Jackson, Michigan 49201.

4 **Q. By whom are you employed and in what capacity?**

5 A. I am employed by Consumers Energy Company (“Consumers Energy” or the “Company”)  
6 as Executive Director of Electric Supply.

7 **Q. Are you the same Richard T. Blumenstock that submitted direct and rebuttal**  
8 **testimony in this proceeding?**

9 A. Yes, I am.

10 **Q. What is the purpose of your second rebuttal testimony?**

11 A. My second rebuttal testimony will provide an overview of the Settlement Agreement filed  
12 in this matter on April 20, 2022 and explain how the Settlement Agreement represents the  
13 most reasonable and prudent means of meeting the Company’s energy and capacity needs,  
14 pursuant to MCL 460.6t(8). In the contested settlement portion of this proceeding, direct  
15 testimony was filed by Michigan Public Service Commission (“Commission” or “MPSC”)  
16 Staff (“Staff”) witness Paul A. Proudfoot; Michigan Environmental Council, Natural  
17 Resources Defense Council, Sierra Club, and Citizens Utility Board (“MNS-CUB”)  
18 witness Douglas B. Jester; Environmental Law and Policy Center, Vote Solar, Ecology  
19 Center, Union of Concerned Scientists, Urban Core Collective (collectively the Clean  
20 Energy Organizations (“CEOs”)) witness James Gignac; Energy Michigan, Inc. (“Energy  
21 Michigan”) witness Alexander J. Zakem; Wolverine Power Supply Cooperative, Inc.  
22 (“Wolverine”) witness Thomas King, Jr.; and Cadillac Renewable Energy, LLC, Genesee  
23 Power Partners Limited Partnership, Decker Energy-Grayling, LLC, Tondu Corporation,

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1 National Energy of Lincoln, LLC, and National Energy of McBain, LLC (collectively the  
2 Biomass Merchant Plants (“BMPs”)) witness Richard A. Polich. My second rebuttal  
3 testimony will respond to portions of the testimony filed by the aforementioned witnesses  
4 but will particularly focus on responding to the assertions raised by the parties contesting  
5 approval of the Settlement Agreement, namely, Energy Michigan, Wolverine, and the  
6 BMPs.

7 **Q. Have you prepared any exhibits in conjunction with your second rebuttal testimony?**

8 A. Yes. I am sponsoring Exhibit A-150 (RTB-5), the April 20, 2022 Settlement Agreement.

9 **Q. Was this exhibit prepared by you or under your direction?**

10 A. Yes.

11 **I. THE SETTLEMENT AGREEMENT**

12 **Q. On page 1 of his contested settlement direct testimony, BMP witness Polich alleges**  
13 **that there are “inconsistencies, failures and risks presented by the proposed**  
14 **Settlement.” Furthermore, on page 1 of his contested settlement direct testimony,**  
15 **Energy Michigan witness Zakem indicates that “Energy Michigan is objecting to the**  
16 **Settlement” and on page 9 of his testimony, Wolverine witness King recommends that**  
17 **the Settlement Agreement be rejected. Please describe the proposed Settlement**  
18 **Agreement which the BMPs, Energy Michigan, and Wolverine are contesting.**

19 A. The Settlement Agreement, as provided in Exhibit A-150 (RTB-5), is the result of  
20 extensive negotiations and represents a compromise on the positions filed by the parties in  
21 this case. The Settlement Agreement proposes to completely resolve this matter and the  
22 signing parties have agreed that the resolution is in the public interest. Numerous other

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1 parties have also agreed not to object to the Settlement Agreement. The Settlement  
2 Agreement also generally provides for the following:

- 3 • The approval of the Company's Proposed Course of Action ("PCA"), as  
4 modified by the Settlement Agreement, as the most reasonable and prudent  
5 means of meeting the Company's energy and capacity needs over the 5-year,  
6 10-year, and 15-year time horizons. The Company will file its next Integrated  
7 Resource Plan ("IRP") consistent with the requirements of MCL 460.6t;
- 8 • The approval of the purchase of the New Covert Generating Facility ("Covert  
9 Plant") and of investments in, and the capacity value of, resources which the  
10 Company will commence within the next three years;
- 11 • The approval of a battery deployment program which will accelerate the  
12 deployment of batteries in the PCA through an additional 75 MW of batteries  
13 being added between 2024 and 2027;
- 14 • The retirement of the entire J.H. Campbell ("Campbell") coal plant in 2025,  
15 approximately 15 years sooner than planned, and accounting mechanisms to  
16 recover the unrecovered book balance and decommissioning costs of the  
17 Campbell Plant. D.E. Karn ("Karn") Units 3 and 4 will continue operating  
18 until 2031, consistent with the design lives of those units, and will continue  
19 to provide capacity and reliability for the Company and its customers as the  
20 PCA is implemented;
- 21 • A one-time solicitation which will seek to acquire: (i) up to 500 Zonal  
22 Resource Credits ("ZRCs") of capacity through power purchase agreements  
23 ("PPA") with dispatchable, nonintermittent generation and (ii) up to

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1 200 ZRCs from unaffiliated third-party intermittent resources and  
2 dispatchable, nonintermittent clean capacity resources;

3 • Accounting approval to defer expenses related to the Campbell site severance  
4 and retention agreement. The Settlement Agreement also provides for  
5 community transition activities related to the Campbell and Karn sites;

6 • The extension of the annual competitive solicitation process used to acquire  
7 the supply-side resource technologies specified in the PCA and the 50%/50%,  
8 Company ownership to third-party ownership construct, as initially approved  
9 in Case No. U-20165, with certain modifications. Among other things, those  
10 modifications provide greater flexibility for the Company to pursue the most  
11 economic projects in each solicitation. Through the annual solicitation  
12 process the Company will continue the solar glidepath, as outlined in the  
13 PCA, which provides for the addition of approximately 8,000 MWs of solar  
14 resources by 2040;

15 • The extension of the Financial Compensation Mechanism (“FCM”) approved  
16 in Case No. U-20165, with certain modifications to the new PPAs for which  
17 the FCM applies;

18 • The extension of the Company’s Public Utility Regulatory Policies Act of  
19 1978 (“PURPA”) avoided cost construct, as approved in Case No. U-20165,  
20 with certain modifications which include modifications impacting eligibility  
21 for avoided cost rates and the Standard Offer Tariff and PPA;

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- 1           • Ongoing Company donations, which will not be recovered from customers,  
2           to a low-income fund that provides bill assistance to Consumers Energy's  
3           electric customers; and
- 4           • Finally, the Settlement Agreement includes numerous actions that the  
5           Company must implement and items that the Company must evaluate and  
6           consider in the Company's next IRP. That includes modeling and analysis  
7           related to distributed resources and generation, emissions analysis, combined  
8           heat and power resource analysis, and new processes to implement in the  
9           Company's public outreach efforts.

10 **Q. What parties to this matter signed the Settlement Agreement?**

11 A. On April 20, 2022, Consumers Energy entered into the Settlement Agreement with the  
12 following parties: the Michigan Public Service Commission Staff, Michigan  
13 Environmental Council, National Resource Defense Council, Sierra Club, Michigan  
14 Attorney General Dana Nessel ("Attorney General"), Environmental Law and Policy  
15 Center, Vote Solar, Ecology Center, Union of Concerned Scientists, Urban Core  
16 Collective, Citizens Utility Board of Michigan, Hemlock Semiconductor Operations, LLC,  
17 Michigan Energy Innovation Business Council, Institute for Energy Innovation, Clean Grid  
18 Alliance, Michigan Electric Transmission Company, LLC, and Great Lakes Renewable  
19 Energy Association.

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1 **Q. What parties to this matter indicated that they do not object to the approval of the**  
2 **Settlement Agreement?**

3 A. The following parties signed a statement of non-objection: Michigan Public Power  
4 Agency, Midland Cogeneration Venture, LP, Association of Businesses Advocating Tariff  
5 Equity, and Residential Customer Group.

6 **Q. What positions did the remaining parties to the proceeding take with respect to the**  
7 **filing of the Settlement Agreement?**

8 A. On May 3, 2022, Energy Michigan filed Objections to the Settlement Agreement. On  
9 May 4, 2022, the following parties filed Objections to the Settlement Agreement: the  
10 Mackinac Center for Public Policy, Wolverine, and the BMPs. Only Energy Michigan,  
11 Wolverine, and the BMPs have filed direct testimony in this contested case proceeding.

12 **Q. On page 4 of his contested settlement direct testimony, Wolverine witness King alleges**  
13 **that the outcome of the Settlement Agreement “not the ‘most reasonable and prudent**  
14 **plan to meet the utility’s energy and capacity needs”” under MCL 460.6t. BMP**  
15 **witness Polich makes similar allegations on page 4 of his contested settlement direct**  
16 **testimony. Furthermore, on page 7 of his direct testimony supporting the Settlement**  
17 **Agreement, Staff witness Proudfoot asserts that the PCA, as modified in the**  
18 **Settlement Agreement, meets the statutory requirements of MCL 460.6t. Does the**  
19 **Settlement Agreement meet the statutory requirements of MCL 460.6t?**

20 A. Yes. As discussed in more detail below, the Settlement Agreement should be approved by  
21 the Commission because it results in the most reasonable and prudent plan to meet the  
22 energy and capacity needs of the Company’s customers.

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1 **Q. Please explain the requirements for approval of an IRP under MCL 460.6(t)?**

2 A. As indicated in my direct testimony filed in this matter, Subsection (8) of MCL 460.6t  
3 requires the Commission to approve an IRP, if it determines the plan represents the most  
4 reasonable and prudent means of meeting the electric utility's energy and capacity needs.  
5 To make this determination, the Commission shall consider whether the plan appropriately  
6 balances all of the following factors:

- 7 i. Resource adequacy and capacity sufficient in quantity to serve anticipated  
8 peak electric load plus applicable Planning Reserve Margin Requirement  
9 (“PRMR”) and Local Clearing Requirement (“LCR”);
- 10 ii. Compliance with applicable state and federal environmental regulations;
- 11 iii. Competitive pricing;
- 12 iv. Reliability;
- 13 v. Commodity price risks;
- 14 vi. Diversity of generation supply; and
- 15 vii. Whether the proposed levels of peak load reduction and Energy Waste  
16 Reduction (“EWR”) are reasonable and cost effective.

17 **Q. Does the Settlement Agreement meet the requirements for approval of an IRP under**  
18 **MCL 460.6t?**

19 A. Yes. One of the over-arching objectives in developing the IRP PCA, and the resulting  
20 Settlement Agreement, was to create the most reasonable and prudent means of meeting  
21 short- and long-term energy and capacity needs. In the Settlement Agreement, the intent  
22 and focus of the Company’s original PCA were maintained, ensuring the Company’s clean  
23 energy transition, as initially set forth in the Company’s 2018 IRP. The PCA, as modified  
24 by the Settlement Agreement, will help lead a faster clean energy transformation by  
25 accelerating the Company’s exit from coal-fired generation while increasing electric

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1 reliability and providing resource adequacy for customers. The Settlement Agreement  
2 satisfies the planning objectives set forth by the Commission in Subsection (8) of  
3 MCL 460.6t.

4 **Q. Please explain how the Settlement Agreement ensures resource adequacy and**  
5 **capacity that is sufficient in quantity to serve anticipated peak electric load plus**  
6 **applicable PRMR and LCR.**

7 A. The PCA, as modified in the Settlement Agreement, has maintained a balance of resource  
8 additions and retirements—backfilling capacity lost to accelerated retirement with the  
9 addition of new baseload resources, expansion of demand-side resources, expansion of  
10 renewable resources, and deployment of battery storage resources. The Settlement  
11 Agreement continues the annual solicitation process which will procure the supply-side  
12 resource technologies specified in the PCA. The Settlement Agreement also provides for  
13 the purchase of the Covert Plant, which is a resource that will move into the Midcontinent  
14 Independent System Operator, Inc. (“MISO”) Zone 7 from PJM Interconnection, LLC  
15 (“PJM”), the continued operation of Karn Units 3 and 4 (with retirement on or before May  
16 31, 2031), consistent with the design lives of those units, and the one-time solicitation  
17 which will procure 700 Zonal Resource Credits (“ZRCs”) of capacity and associated  
18 energy. The Settlement Agreement also provides for numerous mechanisms for the  
19 Company to procure capacity if it is needed, such as the flexibility to procure additional  
20 MWs in the annual solicitation process and the ability to make short-term capacity  
21 additions to address capacity shortfalls which cannot reasonably be addressed through the  
22 annual solicitation process. All of these items provided for in the Settlement Agreement

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1 ensure resource adequacy and capacity that is sufficient in quantity to serve anticipated  
2 peak electric load plus applicable PRMR and LCR.

3 **Q. Please explain how the Settlement Agreement ensures compliance with applicable**  
4 **state and federal environmental regulations.**

5 A. The PCA, as modified in the Settlement Agreement, is in full compliance with all  
6 environmental regulations and mitigates future financial risks of potential environmental  
7 regulation on fossil fuel generation. The PCA also specifies retirement of Campbell  
8 Units 1, 2, and 3 by 2025, approximately 15 years sooner than planned, aggressively  
9 reduces waste, and continues to increase solar generation; all consistent with the  
10 Company's evolved Clean Energy and decarbonization goals. As indicated in my direct  
11 testimony in this case, the Company's Clean Energy Goal calls for reducing carbon  
12 emissions to achieve net zero by 2040 and exit coal by 2025. The Settlement Agreement  
13 keeps the Company on a path to achieving these goals and also would put Michigan on  
14 track to achieve the Governor's Michigan Healthy Climate Plan which calls for reducing  
15 carbon emissions by 52% by 2030 and ending coal-fired generation. This is further  
16 confirmed in the testimony of CEO witness Gignac and MNS-CUB witness Jester as filed  
17 in this contested settlement proceeding. See CEO witness Gignac's Testimony in Support  
18 of Settlement Agreement, page 3; MNS-CUB witness Jester's Testimony in Support of  
19 Settlement Agreement, pages 6-9.

20 **Q. Please explain how the Settlement Agreement ensures competitive pricing.**

21 A. The PCA, as modified in the Settlement Agreement, provides competitive pricing in  
22 numerous ways. First, the Settlement Agreement PCA provides for customer savings of  
23 nearly \$600 million. These savings are achieved through accelerated retirement of existing

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1 assets, acquisition of the Covert Plant, and continuing the strategy of modular deployment  
2 of new generation and demand-side sources. The plan provides for balancing retirements  
3 and additions along a glide path that provides flexibility to adjust plans in the future should  
4 lower-cost technologies become available. The resources identified in the PCA are also  
5 supported by the Company's extensive modeling performed in this case which identified  
6 least-cost resources. The Company also agrees with MNS-CUB witness Jester that  
7 "[e]xtensive modeling conducted by Consumers and by MNS-CUB in this case  
8 demonstrated that retiring Campbell in 2025 is economic for customers." MNS-CUB  
9 witness Jester's Testimony in Support of Settlement Agreement, page 6. Additionally,  
10 competitively bidding new supply-side generation in the one-time solicitation and annual  
11 solicitation processes provides an opportunity to identify and take advantage of the best  
12 implementation opportunities while limiting cost to customers.

13 **Q. Please explain how the Settlement Agreement ensures reliability.**

14 A. The PCA, as modified in the Settlement Agreement, allows the Company to maintain  
15 sufficient capacity resources to meet the expected PRMR. Additionally, the Company  
16 plans to secure resources within the lower peninsula of Michigan that will be transferred  
17 to MISO Zone 7 through the purchase of the Covert Plant and are located in MISO Zone 7  
18 through the solicitations provided for in the Settlement Agreement, ensuring that the LCR  
19 is also met. MNS-CUB witness Jester correctly noted in his testimony filed in this  
20 contested settlement proceeding that the acquisition of the Covert Plant supports reliability  
21 because "Covert will add 1,114 Zonal Resource Credits or ZRCs to MISO Zone 7." See  
22 MNS-CUB witness Jester's Testimony in Support of Settlement Agreement, page 10.

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1 Further, the PCA, as modified in the Settlement Agreement, provides electric  
2 reliability assurance consistent with the PCA as filed. The Company provided a capacity  
3 sufficiency analysis and stochastic risk assessment that highlighted the electric reliability  
4 benefits of the PCA and the PCA, as modified by the Settlement Agreement, is expected  
5 to provide similar reliability benefits. Finally, the flexibility of phased-in modular  
6 resources provides the Company adequate time to mitigate cost, assess reliability within  
7 the reconfigured portfolio, and to modify as necessary.

8 **Q. Please explain how the Settlement Agreement addresses commodity price risks.**

9 A. The PCA, as modified in the Settlement Agreement, provides for a diverse portfolio of  
10 pumped storage and hydro generation, gas generation, wind and solar generation, energy  
11 efficiency, demand response, emerging technologies such as grid modernization and  
12 battery storage, and PPAs with numerous technology types. This represents a balanced  
13 and modular supply plan which provides flexibility to adjust to changes in fuel costs,  
14 technology cost, electric demand, or the business environment and insulates the Company  
15 and its customers from commodity price risks. The Settlement Agreement also continues  
16 the Clean Energy Plan which provides for a modular and scalable supply portfolio which  
17 will provide further opportunities for the utilization of diverse supply resources and  
18 protects against high customer rates.

19 **Q. Please explain how the Settlement Agreement ensures diversity of generation supply.**

20 A. As explained above, the PCA, as modified in the Settlement Agreement, provides for a  
21 diverse portfolio of pumped storage and hydro generation, gas generation, wind and solar  
22 generation, energy efficiency, demand response, emerging technologies such as grid  
23 modernization and battery storage, and PPAs with numerous technology types. In addition,

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1 the Company intends to keep its gas- and oil-fired peaking resources (i.e. Karn Units 3 and  
2 4) operational, to ensure customer reliability needs are met. This blend of resources  
3 provides a significant diversity of generation supply. The modular nature in which many  
4 of these resources are added to the generation supply ensures future agility in response to  
5 changing technology or market conditions.

6 **Q. Please explain whether the proposed levels of peak load reduction (Demand Response**  
7 **(“DR”), Conservation Voltage Reduction (“CVR”), and EWR), in the Settlement**  
8 **Agreement are reasonable and cost effective.**

9 A. The proposed levels of peak load reduction (DR, CVR, and EWR) in the PCA, as modified  
10 in the Settlement Agreement, are aligned with the Company’s testimony in this proceeding,  
11 the DR and EWR potential studies conducted in support of the Company’s IRP and are  
12 reasonable and cost effective. The implementation of demand-side resources ensures  
13 consistent and effective marketing can be developed and deployed. Also, as detailed in the  
14 Settlement Agreement, the Company will continue reporting any changes to the approved  
15 demand-side projects, thereby ensuring that cost will be continuously assessed as the  
16 Company’s implementation of its PCA moves forward.

17 **Q. Please explain other benefits of the Settlement Agreement that the Commission**  
18 **should consider.**

19 A. As explained above, the Settlement Agreement continues the annual solicitation process  
20 for procuring capacity through competitive bids originally approved in Case No. U-20165,  
21 with certain modifications, and provides for a one-time solicitation process for procuring  
22 700 ZRCs of capacity and energy. These solicitations provide an orderly process for the  
23 acquisition of capacity and energy and provide customers with the benefit of competitively

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1 priced energy and capacity. Furthermore, the modifications to the annual solicitation  
2 process provide the Company with greater ability to pursue the most economic projects in  
3 each solicitation. The Settlement Agreement also continues the Company's PURPA  
4 avoided cost construct, as approved in Case No. U-20165, with certain modifications.  
5 Among other things, those modifications will provide Qualifying Facilities ("QFs"), which  
6 the Company has obligation to purchase from under PURPA, with greater access to the  
7 Standard Offer PPA.

8 The Settlement Agreement provides that approximately 50% of the new capacity  
9 that the Company intends to procure through the PCA in each annual solicitation will be  
10 from PPAs and other third-party agreements that do not result in Company ownership and  
11 approximately 50% will be owned by the Company, as acquired through a competitive  
12 bidding process. This approach, which is similar to what was approved in Case No.  
13 U-20165, provides opportunities for third-party resources and resources which will  
14 ultimately be owned by the Company to participate in the annual solicitation process.

15 The Settlement Agreement also provides for an extension of the FCM approved in  
16 Case No. U-20165, and FCM cap, on PPA payments, which appropriately incentivizes the  
17 Company to proceed with the PCA instead of the traditional utility regulatory model which  
18 encourages utilities to build owned assets and discourages pursuit of PPAs due to imputed  
19 debt concerns. This important incentive was correctly acknowledged by MNS-CUB  
20 witness Jester in his testimony filed in this contested settlement proceeding. See, MNS-  
21 CUB witness Jester's Testimony in Support of Settlement Agreement, page 17. The  
22 continued approval of such compensation is critical to creating a stable, sustainable

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1 regulatory and financial model that drives utilization of PPAs that benefit the Company's  
2 customers and the state of Michigan.

3 The Settlement Agreement also provides for the approval of accounting  
4 mechanisms to recover the unrecovered book balance and decommissioning costs of the  
5 Campbell Plant. The recovery of these costs in a manner which helps ensure the financial  
6 health of the utility, as provided for in the Settlement Agreement, is critical to the  
7 Company's ability to retire the Campbell Plant in 2025.

8 The Settlement Agreement further provides for the accelerated deployment of  
9 battery storage in advance of when these resources were planned to be deployed in the  
10 originally proposed PCA. The battery deployment program will accelerate the deployment  
11 of battery storage in the PCA through an additional 75 MW of batteries being added  
12 between 2024 and 2027 and the one-time solicitation will provide an additional opportunity  
13 for battery storage resources to be procured and deployed.

14 The Settlement Agreement provides that the Company will donate \$5 million in  
15 2022 to a low-income fund that provides bill assistance to Consumers Energy's electric  
16 customers and will donate \$2 million annually to the same low-income fund in future years.  
17 These donations will not be recovered in rates and Consumers Energy will consult with the  
18 Attorney General and Staff on the low-income fund receiving the donations.

19 The collaboration agreed to as part of the Settlement Agreement is also extensive  
20 and important to note. This includes: (i) stakeholder engagement prior to the initiation of  
21 the battery deployment program; (ii) stakeholder engagement related to the one-time  
22 solicitation process; (iii) consultation with organizations and community members  
23 regarding the Campbell Plant community transition plan; (iv) consultation with the settling

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1 parties regarding the bid evaluation criteria in the annual solicitation process;  
2 (v) stakeholder outreach to develop a simplified agreement, tariff-based program, or other  
3 mechanism which will allow QFs 150 kWac and below to receive full avoided cost rates;  
4 and (vi) stakeholder outreach related to a distributed generation as a resource modeling  
5 approach. The Settlement Agreement also provides for greater public accessibility during  
6 the public outreach process implemented by the Company prior to its next IRP.

7 **Q. Does the Company’s evidence, as bound into the record in this matter, support the**  
8 **Settlement Agreement?**

9 A. Yes. The Company’s direct testimony, rebuttal testimony, second rebuttal testimony, and  
10 exhibits support approval of the PCA and the Settlement Agreement. The testimony and  
11 exhibits of many other parties, including that of Staff, also support the compromise  
12 positions reached in the Settlement Agreement. Therefore, the evidence submitted in this  
13 matter establishes that the Settlement Agreement is based on substantial record evidence.

14 **II. RESPONSE TO ENERGY MICHIGAN WITNESS ZAKEM**

15 **Q. Beginning on page 1 of his contested settlement direct testimony, Energy Michigan**  
16 **witness Zakem indicates that Energy Michigan objects to the Settlement Agreement**  
17 **because of “impacts on resource adequacy and impacts on the competitive markets.”**  
18 **Do you agree with Mr. Zakem’s concerns?**

19 A. No. Company witness Thomas P. Clark addresses and refutes Mr. Zakem’s alleged  
20 “impacts on resource adequacy and impacts on the competitive markets.” However, there  
21 are other foundational flaws in Mr. Zakem’s arguments which the Commission should  
22 consider in rejecting Energy Michigan’s objections. In this contested settlement  
23 proceeding, Energy Michigan is continuing to rely on its direct testimony as previously  
24 submitted in this case before the Settlement Agreement was reached. See Energy Michigan

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1 witness Zakem’s Contested Settlement Direct, page 2. The problem with that approach is  
2 that Mr. Zakem’s direct testimony was focused on the Company’s purchase of the  
3 Dearborn Industrial Generation (“DIG”), the Kalamazoo River Generating Station  
4 (“Kalamazoo”), and the Livingston Generating Station (“Livingston”) plants (see 8 TR  
5 3171-3178) and the Settlement Agreement no longer provides for the purchase of those  
6 plants in the manner initially proposed by the Company. Mr. Zakem has also made no  
7 adjustment to his initial position to account for the fact that the Settlement Agreement  
8 continues operation of Karn Units 3 and 4 until 2031, as opposed to 2023, as initially  
9 proposed by the Company. Therefore, while Mr. Zakem’s assessment of the Company’s  
10 PCA was incorrect from the outset, it is now also incorrect because it no longer accurately  
11 describes the elements of the PCA, as modified by the Settlement Agreement.

12 In an attempt to rehabilitate his direct testimony, Mr. Zakem claims that the  
13 one-time solicitation provided for in the Settlement Agreement may “already being counted  
14 toward MISO Zone 7’s resource adequacy requirements” but this position is entirely  
15 speculative. Furthermore, for the reasons discussed by Company witness Clark,  
16 Mr. Zakem has failed to establish that the Company’s procurement of resources already  
17 located in MISO Zone 7 is a valid reason to reject the Settlement Agreement.

18 **III. RESPONSE TO WOLVERINE WITNESS KING**

19 **Q. What are the arguments discussed in the contested settlement direct testimony of**  
20 **Wolverine witness King that you will address in your second rebuttal testimony?**

21 A. Mr. King’s arguments focus on purported reliability issues that he claims are at risk in the  
22 Settlement Agreement. Mr. King attempts to suggest that the Company’s PCA, as  
23 modified by the Settlement Agreement, leaves the Company capacity deficient in 2025 and  
24 recommends that “[t]he Commission should simply adjust the timeline for retirement of

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1 Campbell 3.” See Wolverine witness King’s Contested Settlement Direct, page 9.  
2 Mr. King’s claimed Company capacity deficiency is plainly incorrect. Wolverine has also  
3 failed to establish any reliability risks related to the PCA, as modified by the Settlement  
4 Agreement.

5 My second rebuttal testimony will discuss the fatal flaws of the calculations  
6 presented in Mr. King’s exhibit regarding the Settlement Agreement capacity position.  
7 Company witness Clark will address Mr. King’s incorrect assessment of reliability risks  
8 including: the Company’s December 2021 capacity demonstration filing, Case No.  
9 U-21099, underlying load forecast assumptions, and solar capacity accreditation. See  
10 Wolverine witness King’s Contested Settlement Direct, pages 4-9. Company witness Clark  
11 will also address other areas where Wolverine has incorrectly conveyed the reliability risks  
12 of the Settlement Agreement.

13 Finally, the Commission should reject Mr. King request to adjust the timeline for  
14 retirement of Campbell Unit 3, as proposed in the Settlement Agreement. As explained in  
15 response to the BMPs, the terms of the Settlement Agreement do not permit modification  
16 to the Settlement Agreement. Furthermore, proposed modifications to the Settlement  
17 Agreement or alternative settlement proposals are beyond the scope of this contested  
18 settlement proceeding.

19 **Q. What are Mr. King’s arguments regarding the Settlement Agreement capacity**  
20 **position?**

21 A. Beginning on page 3 of his contested settlement direct testimony, Mr. King states that  
22 “Consumers will likely be capacity negative in 2025,” and later discusses the basis for that  
23 opinion. However, Mr. King’s arguments are philosophically and technically flawed.

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1 **Q. What are the flaws of Mr. King's arguments regarding the Settlement Agreement**  
2 **capacity position?**

3 A. There are two initial flaws in Mr. King's representation of the Company's capacity position  
4 which undermine the credibility of Mr. King's position. First, the magnitude of Mr. King's  
5 (erroneously) calculated shortfall is insignificant (28 ZRC, as shown in Exhibit WPSC-7)  
6 for 2025. On page 3 of his contested settlement direct testimony, Mr. King references his  
7 own Exhibit WPSC-6, which states

8 *The 2020-21 OMS-MISO survey projected a small surplus*  
9 *for planning year 2022-23, which was eroded by an*  
10 *increased load forecast, less capacity entering the auction*  
11 *as result of retirements, and the decreased accredited*  
12 *capacity of new resources.*

13 MISO's above statement is indicative of the fact that a small magnitude surplus *or* shortfall  
14 can shift over a relatively short period of time. This is why the Company implements a  
15 strategy of maintaining approximately 200 ZRCs of capacity surplus.

16 The second issue with Mr. King's argument is that he relies on the exclusion of  
17 capacity acquired through the one-time solicitation included in this Settlement Agreement.  
18 His claim that the Company could be capacity negative in 2025 would assume the  
19 Company is wholly unsuccessful in its one-time solicitation – that 0 ZRC of capacity are  
20 acquired through a Request for Proposals soliciting up to 700 ZRCs. That is highly  
21 unlikely. Properly including the addition of up to 700 ZRCs, even Mr. King's own exhibit  
22 shows capacity sufficiency in year 2025 above the Company's strategic surplus amount of  
23 200 ZRC.

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1 **Q. What are the technical flaws of Mr. King’s arguments regarding the Settlement**  
2 **Agreement capacity position?**

3 A. Exhibit WPSC-7 is offered as evidence to support an alleged 28 ZRC capacity shortfall  
4 (disregarding any capacity acquired through a solicitation looking for up to 700 ZRCs) in  
5 2025. The mechanics in the calculation supporting the shortfall for 2025 are incorrect.

6 The calculation is presented in Exhibit WPSC-7. The first column of data,  
7 “**Settlement 2022/23**” is taken directly from the Company’s detailed calculations of  
8 capacity position. The value shown on the row labeled as “Surplus/Deficient” is the correct  
9 ZRC surplus level projected and presented in Figure 6 of my direct testimony in the initial  
10 filing of this case.

11 Mr. King’s next step is to compare the filed capacity position of the 2021 IRP to  
12 the filed capacity position presented in the Company’s December 2021 capacity  
13 demonstration filing, Case No. U-21099. This is summarized in Exhibit WPSC-7 in the  
14 column labeled as “**Cap Dem 2022/23.**” Mr. King has generally populated this column  
15 with appropriate values from Case No. U-21099. He has then created an “Equalization  
16 Adjustment Factor,” which accounts for the difference in final capacity position between  
17 the Capacity Demonstration and the IRP. Although Mr. King’s testimony is not  
18 well-supportive of the calculation, the Company is able to confirm the accuracy of this  
19 value for planning year 2022/2023.

20 Next, in Exhibit WPSC-7, Mr. King calculates a planning year 2025 capacity  
21 position in the column labeled as “**Settlement 2025/26.**” This is consistent with Figure 6  
22 of my direct testimony, with modifications to (i) remove the DIG, Kalamazoo, and  
23 Livingston plant capacity; (ii) extend the capacity for Karn Units 3 and 4; and (iii) add

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1 capacity that will be acquired through the one-time solicitation. I take no issue with these  
2 modifications; however, Mr. King has failed to add capacity provided by the battery  
3 deployment program, which would contribute approximately 14 ZRCs by 2025.

4 The flaw in the analysis, however, occurs in the final column of Exhibit WPSC-7  
5 labeled as “**Cap Dem 2025/26.**” While the lines of data through the row labeled as  
6 “PRMR” are generally accurate (though again, Mr. King fails to include 14 ZRC that will  
7 be provided by the battery deployment program), attention must be brought to the row  
8 “Equalization Adjustment Factor.” While Mr. King referenced this row on page 4, line 21,  
9 of his testimony, he offers little in the way of explanation for it. While this section of my  
10 testimony addresses the Company’s general acceptance of the -343 ZRC value *for planning*  
11 *year 2022/2023*, Mr. King’s testimony fails to explain how this value is calculated or the  
12 appropriate use of this value. In fact, Mr. King offers no explanation whatsoever in his  
13 application of the -343 ZRC value to the final column of Exhibit WPSC-7, which is an  
14 accounting of *planning year 2025/2026* capacity and demand, not 2022/2023. An  
15 appropriate re-calculation of the “Equalization Adjustment Factor” for planning year  
16 2025/26 would be required, but Mr. King failed to do so. In fact, Mr. King’s “Equalization  
17 Adjustment Factors” are only included in his exhibit to calculate the capacity position filed  
18 in the capacity demonstration. That value is readily available in Case No. U-21099,  
19 Exhibit 2 of 11, line 35, column (d), shown to be a +25 ZRC surplus<sup>1</sup>. Application of a  
20 correct “Equalization Adjustment Factor” as well as inclusion of 14 ZRCs of battery  
21 deployment capacity would result in a positive “Surplus/Deficit” value of +39 ZRCs, a  
22 capacity surplus, not a -28 ZRC capacity shortfall, as mis-calculated in Exhibit WPSC-7.

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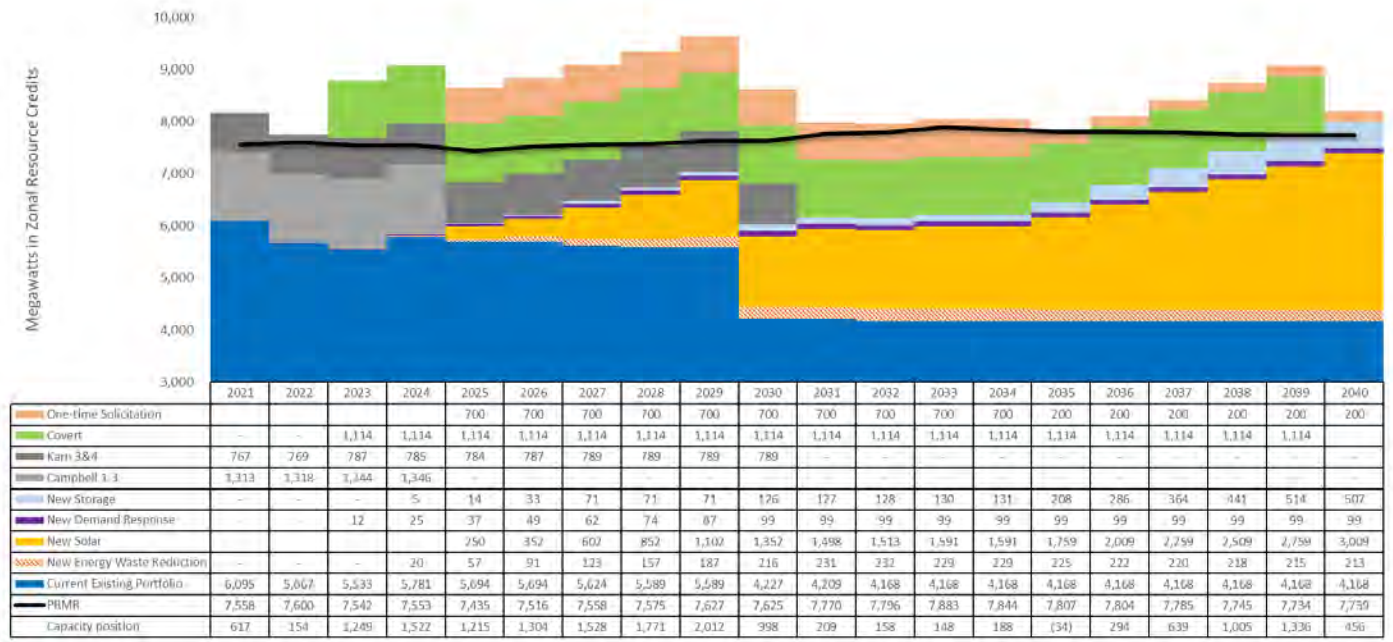
<sup>1</sup> This is consistent with Mr. King’s column “Cap Dem 2022/23,” which is also presented in Case No. U-21099, Exhibit 2 of 11, line 33, column (a).

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1 Combined with up to +700 ZRCs of capacity acquired through the one-time solicitation, it  
2 is abundantly clear that Mr. King’s statement that the Company could be capacity negative  
3 in 2025 is disproven.

4 The prior discussion reconciled Mr. King’s calculated capacity position from the  
5 Company’s December 2021 capacity demonstration, Case No. U-21099. Figure 1, below,  
6 presents the capacity position of the PCA, as modified by the Settlement Agreement.  
7 While Figure 1 indicates a very small capacity shortfall in 2035 (34 ZRCs), the Company  
8 will have sufficient time between now and 2035 to address that shortfall. There are also  
9 numerous mechanisms provided for in the Settlement Agreement which will allow the  
10 Company to address that projected shortfall long before it may happen.

**Figure 1: Proposed Course of Action, as Modified by the Settlement Agreement**



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1 **IV. RESPONSE TO BMP WITNESS POLICH, P.E.**

2 **A. CONSIDERATION OF BIOMASS PLANTS**

3 **Q. Beginning on page 2 of his contested settlement proceeding direct testimony, BMP**  
4 **witness Polich offers eight objections to the Settlement Agreement. Do you agree with**  
5 **Mr. Polich's objections?**

6 **A.** No. I will address Mr. Polich's arguments in more detail below; however, the BMPs'  
7 foundational position in this case has not changed in this contested settlement proceeding  
8 from what the BMPs initially argued prior to settlement. The BMPs are continuing to claim  
9 that the Company did not appropriately consider biomass plants in this IRP and continue  
10 to push for PPA extensions for the individual BMP plants. See BMP witness Polich's  
11 Contested Settlement Direct Testimony, pages 4-6. The BMPs' positions are unreasonable,  
12 not supported in the record, and fail to provide a basis to reject the proposed Settlement  
13 Agreement.

14 As explained by Company witness Keith G. Troyer in his rebuttal testimony, the  
15 Company is not under any obligation to enter new PPAs with the BMPs or extend the  
16 BMPs' existing contracts. Each of the BMPs are above the Company's must-purchase  
17 obligation MW threshold under PURPA and therefore, the Company is not required under  
18 PURPA to continue purchasing from the BMPs once the current PPAs for those plants  
19 expire. Furthermore, while the BMPs concede that the Hillman Plant will retire in 2022  
20 (see BMP witness Polich's Contested Settlement Direct, page 5), the BMPs fail to  
21 acknowledge that the prior owners of the National Energy of Lincoln and McBain plants  
22 contractually agreed to decommission those plants when their current PPAs expire. This  
23 means that the only BMPs which could conceivably enter a new PPA or PPA extension  
24 with the Company are TES Filer City Station (PPA expires in 2025), Grayling Generating

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1 Station (PPA expires in 2027), Cadillac Renewable Energy (PPA expires in 2028), and  
2 Genesee Power Station (PPA expires in December 2030).

3           Moreover, the Company did consider biomass plants in the development of the IRP.  
4 The Company considered biomass plants as it began its modeling process, but due to the  
5 fact that those resources were not viable options on an economic or cost basis, biomass  
6 plants did not pass the Company's resource screen process. It should further be noted that  
7 the plants which make up the BMPs are included in the PCA through the end of their  
8 current PPA terms. Upon expiration of those contracts, those plants are eligible to  
9 participate in the MISO markets.

10           Through the litigation of this proceeding, it has become apparent that the BMPs  
11 take issue with the Company not considering the cost to extend or enter new PPAs with the  
12 existing plants which make up the BMPs. Beyond the fact that the Company has no  
13 obligation to do that, and the fact that the BMP PPAs are not set to expire for numerous  
14 years, the flaw in the BMPs' position is that the Company did not have adequate  
15 information to determine the cost of new PPAs or PPA extensions with the BMPs in the  
16 development of this IRP. And throughout this proceeding, the BMPs have failed to  
17 produce any evidence in the record establishing the costs that the BMPs could agree to in  
18 new PPAs or PPA extension. As explained in the rebuttal testimony of Company witness  
19 Troyer, the cost of current BMP PPAs have not been historically competitive with either  
20 market pricing or the Company's more-recent competitive procurement of new solar  
21 resources. Based on the cost of the BMPs' existing PPAs, the Company had no reason to

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1 assume that the BMP suppliers were willing to accept lower rates than what is provided for  
2 in the current agreements during the development of this IRP.

3           Therefore, prior to addressing the individual objections offered by the BMPs, it is  
4 important to acknowledge that: (i) the Company has no obligation to enter new PPAs or  
5 extend existing PPAs with any of the BMPs; (ii) the Company did consider biomass plants  
6 in the development of its IRP and that type of resource was shown not to be a viable option  
7 on an economic or cost basis; (iii) the BMPs have failed to produce any evidence  
8 establishing the costs that the BMPs could agree to in new PPAs or PPA extension, and  
9 (iv) the existing BMP PPA cost information available to the Company establishes that the  
10 BMPs are not competitive with either market pricing or the Company's recent competitive  
11 procurement results.

12 **Q. Beginning on page 17 of his contested settlement direct testimony, Mr. Polich**  
13 **recommends modifications to the proposed Settlement Agreement which would**  
14 **provide PPA extensions to the BMPs. Should the Commission adopt any changes to**  
15 **the proposed Settlement Agreement?**

16 A. No. As explained on page 7 of Staff witness Proudfoot's direct testimony supporting the  
17 Settlement Agreement, Paragraph 22 of the Settlement Agreement provides that if the  
18 Commission rejects or modifies the Settlement Agreement or any provision of the  
19 Settlement Agreement, the Settlement Agreement shall be deemed to be withdrawn. See  
20 Exhibit A-150 (RTB-5), page 17, Paragraph 22. This is standard language which preserves

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1 the bargain that the settling parties negotiated. Since the Settlement Agreement cannot be  
2 modified, the BMPs' requested modifications should be rejected by the Commission.

3 The BMPs' requested modifications to the settlement agreement are also beyond  
4 the scope of this contested settlement proceeding. As set forth in the Commission's June 7,  
5 2019 Order Approving Settlement Agreement in Case No. U-20165, other proposed  
6 versions of settlements not adopted by the parties who signed the settlement agreement are  
7 not within the scope of issues to be decided by the Commission in a contested settlement  
8 proceeding:

9 The Commission agrees with Consumers that SEIA's  
10 proposal is outside the scope of this contested settlement  
11 agreement. The issue to be decided in this case is whether  
12 the criteria set forth in Rule 431(5)(a) through (c) have been  
13 satisfied so that the Commission may approve of the  
14 settlement agreement at issue here. Other proposed versions  
15 of settlements not adopted by the parties who signed the  
16 settlement agreement are not properly before the  
17 Commission. Further, the Commission agrees with the Staff  
18 that SEIA's proposal should not be used to derail the  
19 settlement agreement in this case. Accordingly, the  
20 Commission rejects SEIA's recommendation to make  
21 approval of the settlement agreement contingent on SEIA's  
22 proposal. [MPSC Case No. U-20165, June 7, 2019 Order  
23 Approving Settlement Agreement, page 82.]

24 Since the BMPs' proposed Settlement Agreement modifications are beyond the scope of  
25 this contested settlement proceeding, they should be rejected by the Commission.

26 Furthermore, as set forth above, the BMPs have failed to produce any evidence in  
27 the record establishing that extended PPAs with the BMPs would be economic compared  
28 to other resource options. And the record establishes just the opposite. Based on historic  
29 information related to existing PPAs, the BMPs are not competitive with either market  
30 pricing or the Company's recent competitive procurement results. Therefore, even if the  
31 Settlement Agreement could be modified, which it cannot, and if the BMPs' proposal was

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1 within the scope of this proceeding, which it is not, there is still no basis to adopt the BMPs  
2 recommended modifications to the Settlement Agreement because the record does not  
3 establish that the PPA extensions with the BMPs would be economic compared to other  
4 resource options.

5 **B. CAPACITY POSITION**

6 **Q. Beginning on page 6 of his contested settlement direct testimony, Mr. Polich claims**  
7 **that the Settlement Agreement PCA will result in excess capacity between 2023 and**  
8 **2030 and capacity shortages between 2031 and 2038. Do you agree?**

9 A. I do not agree with Mr. Polich's generalizations regarding the Company's capacity position  
10 under the PCA, as modified by the Settlement Agreement. Specifically, I do not agree that  
11 the Settlement Agreement PCA results in capacity shortages. As explained in response to  
12 Wolverine witness King, under the PCA, as modified by the Settlement Agreement, the  
13 Company maintains sufficient capacity to serve customers. See Figure 1 of this second  
14 rebuttal testimony. Furthermore, below I discuss that Mr. Polich's own Exhibit BMP-7  
15 (RAP-7) supports the capacity sufficiency of the Settlement Agreement.

16 With respect to the BMPs allegations of excess capacity, I also disagree with Mr.  
17 Polich that the capacity amounts in any year of the PCA is to the detriment of customers.  
18 I will discuss this in more detail below.

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1 **Q. On page 8, beginning on line 1 of his contested settlement direct testimony, Mr. Polich**  
2 **states the Settlement Agreement results in excess capacity, exposing customers to**  
3 **unreasonable expense. Mr. Polich opines that the addition of the Covert Plant in 2023**  
4 **means customers will be paying for two years of “unnecessary costs for the Covert**  
5 **capacity that is unnecessary” and that one-time solicitation “is not needed until 2030.”**  
6 **Do you agree with Mr. Polich’s claims?**

7 A. No. The record in this case demonstrates that the Company initially proposed to acquire  
8 the Covert Plant *and* the DIG, Kalamazoo, and Livingston plants to retire Karn Units 3 and  
9 4, which are capacity resources, *and* Campbell Units 1, 2, and 3, which are capacity and  
10 energy resources. In other words, the acquisition of any particular unit was not assigned  
11 to the retirement of any particular unit. The acquisitions and retirements were considered  
12 as a whole based on the impact of the energy and capacity lost and the energy and capacity  
13 gained. Through the settlement process, the settling parties agreed that the Company would  
14 not purchase the DIG, Kalamazoo, and Livingston plants, as originally proposed.  
15 However, in order to retire Campbell Units 1, 2, and 3, the Company still needs to acquire  
16 the Covert Plant and the Purchase Sale Agreement (“PSA”) for that plant provides for the  
17 purchase in 2023. Therefore, Mr. Polich is plainly incorrect in alleging that the Covert  
18 Plant capacity is “unnecessary.” Nearly every party in this proceeding supported  
19 acquisition of the Covert Plant in 2023. This acquisition brings dispatchable baseload  
20 capacity into MISO and Zone 7 and will support the replacement of the energy and capacity  
21 of the units proposed for retirement in this IRP.

22 Mr. Polich has also not established that the Company has any ability to move the  
23 start date of the Covert Plant purchase. Since the PSA provides for the Covert Plant to be

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1 purchased in 2023, attempting to move that date is not possible under the terms of the  
2 agreement. Furthermore, even if the Covert Plant does provide surplus energy and capacity  
3 for a short period, the Company can monetize the energy and capacity of the Covert Plant  
4 by selling it into the MISO markets and using the resulting revenue to lower power supply  
5 costs to the benefit of customers. The Company disagrees with Mr. Polich that customers  
6 will face economic harm as a result of the Company owning the Covert Plant.

7           Moreover, without the acquisition of the DIG, Kalamazoo, and Livingston units, as  
8 initially proposed by the Company, the one-time solicitation included in the proposed  
9 Settlement Agreement also supports the retirement of Campbell Units 1, 2, and 3. It is  
10 expected that the 500 ZRCs of dispatchable generation and the 200 ZRCs of intermittent  
11 and non-intermittent clean resources will provide sufficiency of supply to support  
12 retirement of the Campbell Units. However, until such resources are acquired and  
13 operational on behalf of customers, the Settlement Agreement provides for continued  
14 operation of Karn Units 3 and 4, which provide low-cost capacity for the benefit of  
15 customers. The continued operation of Karn Units 3 and 4 further addresses reliability  
16 concerns for customers. These low-cost capacity resources will continue to be evaluated  
17 in future IRPs, along with other existing assets, to identify if they continue to serve  
18 customer needs reliably and affordably. The Settlement Agreement identifies the plan to  
19 cease operations of these units by May 31, 2031, however, the Company intends to manage  
20 its capacity surplus position in the best interests of its customers. Because the one-time  
21 solicitation will support the retirement of Campbell Units 1, 2, and 3, and the need for  
22 continued operations of Karn Units 3 and 4 can be assessed in the future, the BMPs have

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1 not established that the one-time solicitation is unnecessary or to the detriment of  
2 customers.

3 **Q. Beginning on page 13 of his contested settlement direct testimony, Mr. Polich claims**  
4 **that the PCA, as modified in the Settlement Agreement, results in a capacity shortfall**  
5 **position in years 2031 through 2038. Do you agree with Mr. Polich's alleged capacity**  
6 **shortfall?**

7 A. No. The calculation described by Mr. Polich and included as Exhibit BMP-9 (RAP-9) is  
8 misleading and inconsistent with the modeling presented in this case. Company witness  
9 Clark discusses the issue of solar accreditation itself, in further detail. Mr. Polich suggests  
10 that *if* a change to solar accreditation is made at MISO, the PCA would result in capacity  
11 shortfalls eight years into the future. This argument is not compelling for two primary  
12 reasons.

13 First, the PCA was developed using current MISO solar capacity accreditation  
14 practices. While discussions in MISO have raised the possibility of changes to solar  
15 capacity accreditation, it would be premature to adopt such changes ahead of MISO itself  
16 issuing the rule change. In fact, at the Company's existing solar facilities, capacity  
17 accreditation, based on actual performance, has been as high as 65%. While the possibility  
18 of lowering the accreditation is under consideration, actual performance will ultimately  
19 dictate the levels of capacity customers receive from these resources. Mr. Polich's Exhibit  
20 BMP-7 (RAP-7) actually presents a capacity position for the Company under a 50% solar  
21 accreditation and demonstrates that the Company has no capacity shortfall through 2040.

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1 See Exhibit BMP-7 (RAP-7), line 24.<sup>2</sup> Table 1, below, which is pulled directly from the  
2 referenced line of Exhibit BMP-7 (RAP-7) illustrates the capacity position calculated by  
3 Mr. Polich.

**Table 1: Capacity Position Presented in Exhibit BMP-7 (RAP-7)**

<u>Year</u>	<u>Settlement Agreement Net Capacity in Excess of PRMR (Line 24)</u>
2021	617
2022	154
2023	1,249
2024	1,517
2025	1,201
2026	1,271
2027	1,457
2028	1,700
2029	1,942
2030	927
2031	138
2032	88
2033	78
2034	118
2035	396
2036	224
2037	568
2038	934
2039	1,270
2040	1,514

4 Since Mr. Polich's own exhibit clearly supports the sufficiency of capacity in the  
5 Settlement Agreement, as set forth above, his claim of a capacity shortfall should be  
6 rejected.

7 Second, Mr. Polich's alleged and miscalculated capacity shortfall is projected to  
8 occur eight years into the future. The Company will file at least one, if not multiple, IRPs

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<sup>2</sup> Note that Figure 1 in my second rebuttal testimony provides the Company's actual PCA capacity position, as modified in the Settlement Agreement. The Company is only providing the purported "Settlement Agreement Net Capacity in Excess of PRMR," as provided in Exhibit BMP-7 (RAP-7), to demonstrate that Mr. Polich's own calculations show that the PCA has no capacity shortfalls. Exhibit BMP-7 (RAP-7) contains errors which include the omission of the battery storage deployment program beginning in planning year 2024/2025.

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1 between now and that time. If changes to solar accreditation occur at MISO, the Company  
2 has ample time to respond and adjust the PCA. Furthermore, as set forth above, under the  
3 PCA, as modified by the Settlement Agreement, and the numerous mechanisms provided  
4 for in the Settlement Agreement which will allow the Company to address that projected  
5 shortfall long before it happens, the Company will maintain sufficient capacity to serve  
6 customers.

7 C. ONE-TIME SOLICITATION

8 **Q. Beginning on page 9 of his contested settlement direct testimony, BMP witness Polich**  
9 **suggests that the one-time solicitation proposed in the Settlement Agreement is**  
10 **“deeply flawed.” Do you agree with Mr. Polich’s claims regarding the solicitation?**

11 A. No. The first “flaw” Mr. Polich claims is that the one-time solicitation timing will favor  
12 existing generation facilities, and he cites engineering, financing, and construction time  
13 limitations, as well as delays in the MISO interconnection process. The Company  
14 disagrees that this is a flaw in the design of the solicitation. As explained above, the  
15 resources acquired in the one-time solicitation will help replace the capacity and energy  
16 lost by Campbell Units 1, 2, and 3 in 2025. Furthermore, beyond speculating what plants  
17 can participate, Mr. Polich fails to establish anything unreasonable about the solicitation.  
18 The solicitation will provide capacity and energy to meet the needs of the Company and its  
19 customers, and the characteristics of the resources sought in the solicitation are consistent  
20 with the results of the extensive modeling performed by the Company in this case. As  
21 explained by Company witness Sara T. Walz, the Company’s modeling selected natural  
22 gas units to satisfy large capacity and energy needs, which is consistent with the  
23 characteristics sought in the 500 ZRC tranche. The Company’s modeling also selected  
24 clean resources, like solar, which is consistent with the 200 ZRC tranche.

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1           Mr. Polich’s second claimed flaw relies on incorrect data assumptions.  
2 Specifically, Mr. Polich incorrectly states that MISO Zone 7 is projected to be 397.4 ZRCs  
3 short in 2023. See BMP witness Polich’s Contested Settlement Direct, page 10. This is  
4 inaccurate. Mr. Polich has incorrectly interpreted page 13 of Exhibit BMP-8 (RAP-8),  
5 which provides the results of the Planning Year 2022/2023 Planning Resource Auction  
6 (“PRA”). The results presented in this summary are not indicative of any projection of  
7 Zone 7 in Planning Year 2023/2024, as stated in Mr. Polich’s testimony. Further, the  
8 Company’s addition of the Covert Plant results in an increase of capacity resources of over  
9 1,100 ZRCs in Zone 7 in 2023.

10           Mr. Polich correctly stated that the MISO PRA for planning year 2022-2023  
11 resulted in higher clearing prices than recent historical averages, as well as a shortfall  
12 position for Zone 7. However, the PCA, as presented in this Settlement Agreement,  
13 provides for long-term capacity sufficiency for customers. Mr. Polich has himself  
14 acknowledged that the Settlement Agreement will provide a capacity surplus for customers  
15 for years 2023 through 2030. See BMP witness Polich’s Contested Settlement Direct,  
16 page 8. As has been discussed repeatedly in this case, Consumers Energy customers are  
17 not responsible for resource adequacy requirements for the entire Zone 7, which includes  
18 customers served by alternative energy suppliers (“AESs”) as well as other utilities. The  
19 Settlement Agreement ensures PRMRs are met for Consumers Energy customers. Please  
20 see the testimony of Company witness Clark for additional discussion on this matter.

21           Mr. Polich’s third claimed flaw suggests that the BMPs are precluded from  
22 participation in the one-time solicitation because of their existing contracts and  
23 dispatchability constraints. See BMP witness Polich’s Contested Settlement Direct,

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1 page 11. However, this limitation is untrue, and one created by the BMPs. At the outset,  
2 Mr. Polich's alleged flaw is a red herring because the Company was under no obligation  
3 to issue the one-time solicitation in a manner that would align sought PPA start dates with  
4 the expiration of the BMPs current PPAs. Because the current PPAs of the BMPs expire  
5 in different years between 2025 and 2030, it would not be possible to align the one-time  
6 solicitation with the expiration of every BMP PPA. Furthermore, while the solicitation is  
7 seeking bids which will provide the Company with capacity credit in the MISO Zone 7  
8 starting in the 2025 Planning Year, this would not preclude certain BMPs from submitting  
9 bids which take into account current contractual commitments. Such contractual  
10 commitments could be evaluated in the solicitation when determining the overall  
11 economics of a bid.

12 Mr. Polich also suggests that the BMPs are excluded from the 500 ZRC tranche of  
13 the one-time solicitation because it "provides for hourly dispatch" and the BMPs are  
14 "dispatched on 24 hours-notice." BMP witness Polich's Contested Settlement Direct,  
15 page 11. However, Mr. Polich does not correctly represent the Settlement Agreement  
16 language which provides that "[t]his tranche will seek dispatchable, nonintermittent  
17 generation *capable* of dispatching up or down in every hour of the year in response to  
18 wholesale energy market signals." See Exhibit A-150 (RTB-5), page 6, Paragraph 6  
19 (emphasis added). It is also notable that during this proceeding Mr. Polich has claimed  
20 that the BMPs "generation facilities can provide *around the clock*, renewable, *dispatchable*  
21 and reliable power generation." See 7 TR 2684 (emphasis added). Mr. Polich's statements  
22 in his contested settlement direct testimony are therefore inconsistent with his prior  
23 testimony in this proceeding which suggested that the BMPs are "dispatchable" "around

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1 the clock.”<sup>3</sup> It should also be noted that, under existing BMP PPAs, certain BMPs are  
2 offered into the MISO Day-Ahead Market as units which can dispatch on an hourly basis.  
3 Since the MISO Day-Ahead Market clears the day prior to operation, the plants are  
4 provided dispatch notice prior to actual operation.

5 Mr. Polich’s fourth alleged flaw in the one-time solicitation suggests that the second  
6 tranche which seeks to procure 200 ZRCs does not define “clean capacity resources” and  
7 could mean any resources cleaner than “Consumers existing generation resources” and  
8 therefore “natural gas plants could offer proposals.” BMP witness Polich’s Contested  
9 Settlement Direct, page 11. This fourth alleged flaw is not an actual flaw in the one-time  
10 solicitation and instead represents Mr. Polich’s interpretation of the second tranche of the  
11 one-time solicitation. The Settlement Agreement was entered by 18 parties and represents  
12 a compromise reached by those parties. The terms of the Settlement Agreement speak for  
13 themselves and Mr. Polich’s observations are irrelevant. Nevertheless, Mr. Polich’s  
14 interpretation of the second tranche simply does not make sense. The Company’s  
15 generation portfolio includes fossil fuel and clean capacity resources such as solar and  
16 hydro generation. Since the Company already possesses clean capacity resources in its  
17 generation portfolio, Mr. Polich’s interpretation that this tranche “can mean any generation  
18 resource *cleaner* than Consumers existing generation resources” (emphasis added) would  
19 produce absurd results because nothing could be “cleaner” than the clean capacity  
20 resources the Company already has.

---

<sup>3</sup> Mr. Polich has presented numerous claims in this proceeding that the BMPs are dispatchable and has not previously explained any of the limitations on dispatchability expressed in his contested settlement direct testimony. See, e.g., 7 TR 2684, 2689, 2691, 2698, 2703, 2714, 2715, 2721, 2722, 2728. Mr. Polich also compared the operation of the BMPs to the DIG gas plant, claiming that “[a]s with DIG, these plants are dispatchable and provide equivalent availability.” 7 TR 2715.

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1           Mr. Polich also fails to provide the full text describing the “clean capacity  
2 resources” that can participate in the second tranche of the one-time solicitation. The  
3 Settlement Agreement specifically provides that “[t]his tranche will seek intermittent  
4 resources and dispatchable, nonintermittent clean capacity resources (*including battery  
5 storage resources*) providing capacity which meets the Local Clearing Requirement of  
6 MISO Zone 7.” Exhibit A-150 (RTB-5), page 6, Paragraph 6 (emphasis added). Since the  
7 Settlement Agreement provides “battery storage resources” as an example of the  
8 “dispatchable, nonintermittent clean capacity resources” that can participate in the second  
9 tranche, the Settlement Agreement is not “very ambiguous,” as Mr. Polich claims. See  
10 BMP witness Polich’s Contested Settlement Direct, page 11.

11           Mr. Polich’s fifth alleged flaw in the one-time solicitation assumes that the “One-  
12 Time Solicitation will likely result in Consumers acquiring substantial amount of natural  
13 gas capacity in addition to the Covert capacity” and discusses “volatility of natural gas  
14 pricing.” BMP witness Polich’s Contested Settlement Direct, page 12. In making this  
15 argument, Mr. Polich is speculating on the outcome of the one-time solicitation for  
16 500 ZRCs of dispatchable resources, which is unproductive. For the reasons set forth by  
17 Company witness Brian D. Gallaway in the record, Mr. Polich’s discussion of gas price  
18 volatility should also be rejected. Mr. Gallaway established that gas price volatility is not  
19 expected to continue into the future. Furthermore, Mr. Polich’s suggested “need for a more  
20 fuel diverse generation portfolio” (see BMP witness Polich’s Contested Settlement Direct,  
21 page 12) ignores that the Company will have an incredibly diverse resource portfolio that  
22 includes: pumped storage and hydro generation, gas generation, wind generation, solar  
23 generation, energy efficiency, DR, and emerging technologies such as grid modernization

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1 and battery storage to meet the future demand of its customers. The Company also  
2 maintains PPAs with numerous technology types.

3 Mr. Polich's sixth and final alleged flaw with the one-time solicitation suggests that  
4 it is flawed because it solicits "only intermittent generation because solar generation with  
5 battery storage will likely be too expensive to compete with solar generation without  
6 battery storage and due to shortages of materials." BMP witness Polich's Contested  
7 Settlement Direct Testimony, page 12. Here, again, Mr. Polich is speculating on the  
8 outcomes of the 200 ZRC tranche. The one-time solicitation is a competitive bidding  
9 process which will consider the value of the resources which are bid. If certain resources  
10 are "too expensive," as Mr. Polich claims, that issue will naturally be resolved through the  
11 evaluation and ranking of eligible bids.

**D. OTHER ISSUES**

12  
13 **Q. On page 14 of his contested settlement direct testimony, Mr. Polich states that the**  
14 **Settlement Agreement does not "meet the intent of being carbon neutral by 2040 as**  
15 **[sic] stated in Settlement Section 16." Do you agree?**

16 **A.** No. First of all, Mr. Polich purported "intent of being carbon neutral by 2040" is not a  
17 term of the Settlement Agreement. Paragraph 16 of the Settlement Agreement merely  
18 reiterates that the Company's filed IRP "set forth a proposal to be Carbon Neutral by 2040  
19 and retire all coal generation by 2025." See Exhibit A-150 (RTB-5), page 13,  
20 Paragraph 16. While the Company still aims to be carbon neutral by 2040, this is not a  
21 requirement in the Settlement Agreement. Still, there is nothing in the Settlement  
22 Agreement that will necessarily impede the Company's ability to meet its goal.

23 In an attempt to support his argument regarding not meeting carbon neutrality by  
24 2040, Mr. Polich asserts that "Consumers is relying on Covert and 200 MW of generation

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1 from PPAs originating under the One-Time Solicitation” and that “[t]hese are fossil  
2 generation resources and are not carbon neutral.” BMP witness Polich’s Contested  
3 Settlement Direct, page 14. However, Mr. Polich’s assumptions are not accurate. First, as  
4 made clear in my direct testimony, the 20-year capacity plan provided by the Company in  
5 this IRP assumed cessation of operations of the Covert Plant by May 31, 2040. The final  
6 solution in 2040 will vary dependent upon the evolution of cleaner technologies, the  
7 possibility of carbon sequestration technologies, and potential for carbon offsets. Second,  
8 Mr. Polich is incorrect that the Company will acquire 200 MWs of “fossil generation  
9 resources” in the one-time solicitation that will operate beyond 2040. Mr. Polich implies  
10 that the 200 ZRC tranche, which can result in contracts up to 25 years, could result in fossil  
11 generation resources but that is inconsistent with the description of that tranche which  
12 provides that only “intermittent resources and dispatchable, nonintermittent clean capacity  
13 resources (including battery storage resources)” are eligible. See Exhibit A-150 (RTB-5),  
14 page 6, Paragraph 6. Mr. Polich has therefore not established that the Covert Plant purchase  
15 or the one-time solicitation will result in the Company not meeting its carbon neutrality  
16 goal.

17 Mr. Polich also suggests the resource mix included in the PCA will impact the  
18 Company’s ability to meet its carbon neutrality goal. Specifically, Mr. Polich questions  
19 solar production levels, a lack of battery storage, and levels of energy market purchases.  
20 See BMP witness Polich’s Contested Settlement Direct, page 14. These matters have all  
21 been extensively addressed and refuted by the evidence provided by the Company in this  
22 case. First, the Company utilized and successfully supported use of National Renewable  
23 Energy Laboratories (“NREL”) projections for solar operating factors. Testimony

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1 provided by Company witness Jeffrey E. Battaglia supports these projections from  
2 third-party and reputable sources. Secondly, the Settlement Agreement provides for an  
3 incremental 75 MW of battery storage capacity by 2027, as compared to the initial PCA.  
4 This brings the total capacity of battery storage to 550 MW installed throughout the study  
5 period on top of 1,170 MW of Ludington pumped storage capacity. Lastly, purchase of  
6 energy from MISO's energy market is a benefit to customers, to ensure the lowest-cost  
7 resources are used to meet their needs. The Company's Net Zero Carbon goal accounts for  
8 carbon emissions from those market purchases, as discussed in testimony presented by  
9 Company witness Heather A. Breining.

10 **Q. On page 7 of his contested settlement direct testimony, Mr. Polich suggests that**  
11 **potential risk of capacity shortages in Zone 7 could prevent retirement of Karn Units**  
12 **3 and 4. Specifically, Mr. Polich suggests that the units could be designated as a**  
13 **System Support Resource ("SSR") by MISO. Does this represent a significant risk to**  
14 **customers?**

15 A. No. Mr. Polich's discussion of an SSR designation for Karn Units 3 and 4 does not  
16 represent a significant risk to customers because, as discussed above, Mr. Polich's position  
17 is based on a flawed interpretation of the Company's future capacity position. Mr. Polich  
18 has failed to establish that the Company will experience a capacity shortage between 2031  
19 and 2038 and therefore has not established that there is a "likelihood that MISO will  
20 designate one or more of Consumers' fossil fuel Karn generating plants as System Support  
21 Resource and not allow their retirement." BMP witness Polich's Contested Settlement  
22 Direct, page 7.

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1           Mr. Polich also fails to accurately represent the customer benefit of Karn Units 3  
2 and 4 and what an SSR designation actually means for customers. An SSR designation  
3 would not be due to a capacity or energy shortfall. An SSR designation would result from  
4 an electric transmission system deficiency that must be mitigated before Karn Units 3 and  
5 4 could be retired. Karn Units 3 and 4 will continue to operate to ensure near-term  
6 reliability for the benefit of Consumers Energy customers. These units may be operated  
7 through May 31, 2031, depending on the Company's capacity needs and the outcome of  
8 the Company's resource procurement efforts. The cost to maintain operations of Karn  
9 Units 3 and 4 is very low<sup>4</sup>, compared to many alternatives available to meet load  
10 obligations which means that customers will not be required to pay high costs for extensive  
11 capacity and reliability benefits provided by these units. Moreover, even if Karn Units 3  
12 and 4 were designated as SSR units, the cost burden associated with that designation would  
13 shift to all customers who benefit from the reliability assets, in this case, all customers in  
14 Zone 7. Moreover, the SSR period would only be in place while system improvements are  
15 made to accommodate retirement of Karn Units 3 and 4. At the time the Company submits  
16 an Attachment Y with MISO, to initiate the process of retirement, if MISO designates the  
17 units as SSR for Zone 7, the entirety of the zone would then financially support the

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<sup>4</sup> See page 1 of Exhibit A-51 (NJK-2) Revised, page 1 of Exhibit A-52 (NJK-3) Revised, and page 1 of Exhibit A-53 (NJK-4) Revised.

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1 continued operation of the units. Therefore, an SSR designation does not pose an increased  
2 risk to customers.

3 **Q. Beginning on page 15 of his contested settlement direct testimony, Mr. Polich suggests**  
4 **that there are risks associated with the Company’s proposal solar generation. Do you**  
5 **agree with Mr. Polich’s assessment?**

6 A. No. For the reasons discussed in the second rebuttal testimony of Company witness Clark,  
7 the Company disagrees with Mr. Polich’s assessments of the risks of solar procurement  
8 and development.

9 **Q. On page 6 of his contested settlement direct testimony, Mr. Polich suggests that the**  
10 **Settlement Agreement “fails to consider both the employment and tax benefits of the**  
11 **Biomass Plants as well as the full panoply of their environmental benefits as identified**  
12 **in my initial direct testimony.” Do you agree with Mr. Polich’s criticism of the**  
13 **Settlement Agreement?**

14 A. No. The BMPs positions on these issues were extensively refuted by the Company’s record  
15 evidence and briefs. The BMPs position regarding the consideration of the employment  
16 and tax benefits of the BMPs is also based on a flawed reading of MCL 6t(8)(b). See  
17 BMPs’ May 4, 2022 Objections, page 6. The BMPs’ reading of the requirements of  
18 Section 6t(8)(b) is also incorrect. That provision addresses what the Commission shall  
19 determine in approving an IRP. See MCL 460.6t(8). In relevant part, Section 6t(8)(b)  
20 provides “[t]o the extent practicable, the construction or investment in a new or existing  
21 capacity resource in this state is completed using a workforce composed of residents of this  
22 state as determined by the commission.” MCL 460.6t(8)(b). Section 6t(8)(b) therefore  
23 only applies when a utility is proposing to construct a new resource or invest in an existing

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1 resource and aligns with the cost approval provision of the IRP law which allows utilities  
2 to seek pre-approval of those construction and investment costs in an IRP. MCL 460.6t(11)  
3 (“the commission shall specify the costs approved for the construction of or significant  
4 investment in an electric generation facility...”). There is no reasonable interpretation of  
5 Section 6t(8)(b) which could link that provision to a required evaluation of the “instate  
6 employment and tax benefits” of the BMPs. The Company does not own the BMPs and is  
7 not proposing any construction or investment related to those plants.

8 **V. CONCLUSION**

9 **Q. Based on the contested settlement direct testimony filed by Energy Michigan,**  
10 **Wolverine, and the BMPs, have those parties established any basis for the**  
11 **Commission to reject the Settlement Agreement?**

12 A. No. For the reasons discussed above, Energy Michigan and Wolverine have failed to  
13 establish that there are detrimental reliability and resource adequacy impacts related to the  
14 Settlement Agreement. Wolverine’s assertion that the Company will experience a capacity  
15 deficiency in 2025 was also shown to be incorrect. As explained by Company witness  
16 Clark, Energy Michigan and Wolverine have also refused to provide the capacity  
17 projections and future capacity plans for Energy Michigan’s AES members and Wolverine.  
18 Therefore, beyond the fact that Energy Michigan’s and Wolverine’s claims are incorrect  
19 about the impact of the Settlement Agreement on Zone 7, Wolverine’s and Energy  
20 Michigan’s failure to provide capacity forecasts and future capacity plans also makes clear  
21 that their criticisms of the Settlement Agreement cannot be sustained. Wolverine and

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1 Energy Michigan have failed to establish any basis for the Commission to not approve the  
2 Settlement Agreement.

3 The BMPs have also failed to establish any basis for the Commission to not approve  
4 the Settlement Agreement. The BMPs positions should be rejected because: (i) the  
5 Company has no obligation to enter new PPAs or extend existing PPAs with any of the  
6 BMPs; (ii) the Company did consider biomass plants in the development of its IRP and  
7 that type of resource was shown not to be a viable option on an economic or cost basis; (iii)  
8 the BMPs have failed to produce any evidence establishing the costs that the BMPs could  
9 agree to in new PPAs or PPA extension; and (iv) the existing BMP PPA cost information  
10 available to the Company establishes that the BMPs are not competitive with either market  
11 pricing or the Company's recent competitive procurement results. For the reasons detailed  
12 above, the BMPs have also failed to establish any real flaws in the Settlement Agreement  
13 which would prevent the Settlement Agreement from being approved by the Commission.

14 **Q. Does this conclude your second rebuttal testimony?**

15 **A. Yes.**

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) )  
Emergency Order: Midcontinent )  
Independent System Operator )  
(MISO) )  
\_\_\_\_\_ )

Order No. 202-26-16

Exhibit to  
Motion to Intervene and Request for Rehearing and Stay of  
Public Interest Organizations

Exhibit 57  
Jester 2021 Direct  
Testimony

## 1 STATE OF MICHIGAN

## 2 BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

3 In the matter of the application of  
CONSUMERS ENERGY COMPANY for Case No. U-21090  
4 approval of an Integrated Resource  
Plan under MCL 460.6t, certain Volume 10  
5 accounting approvals, and other relief.

6 \_\_\_\_\_/  
7 CROSS-EXAMINATION (Settlement Agreement)

8 Proceedings held via Microsoft Teams in the  
9 above-entitled matter before Sally L. Wallace,  
10 Administrative Law Judge with MOAHR, for the Michigan  
11 Public Service Commission, Lansing, Michigan, on  
12 Friday, May 20, 2022, at 9:06 a.m.

## 13 APPEARANCES:

14 ROBERT W. BEACH, ESQ.  
BRET A. TOTORAITIS, ESQ.  
15 MICHAEL C. RAMPE, ESQ.  
Consumers Energy Company  
16 One Energy Plaza, Room EP11-223  
Jackson, Michigan 49201

17 On behalf of Consumers Energy Company

18 THOMAS J. WATERS, ESQ.  
The Running Wise Law Firm  
19 1501 Cass Street, Suite D  
20 P. O. Box 686  
Traverse City, Michigan 49685

21 On behalf of Biomass Merchant Plants (BMPs)

22 CELESTE R. GILL, Asst. Attorney General  
23 525 W. Ottawa Street, 7th floor  
P.O. Box 30755  
24 Lansing, Michigan 48909

25 On behalf of Michigan Attorney General

(Continued)

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of  
**CONSUMERS ENERGY COMPANY** for  
Approval of an Integrated Resource Plan  
under MCL 460.6t, certain accounting  
approvals, and for other relief.

U-21090

ALJ Sally L. Wallace

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**TESTIMONY OF DOUGLAS B. JESTER  
IN SUPPORT OF SETTLEMENT AGREEMENT**

**ON BEHALF OF**

**THE MICHIGAN ENVIRONMENTAL COUNCIL,  
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB,  
AND CITIZENS UTILITY BOARD OF MICHIGAN**

**May 9, 2022**

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1     **I.    INTRODUCTION**

2     **Q.    Are you the same Douglas Jester who previously filed testimony in this case?**

3     A.    Yes.

4     **Q.    On whose behalf is this testimony being offered?**

5     A.    I am testifying on behalf of Michigan Environmental Council (MEC), Natural Resources  
6           Defense Council (NRDC), and Sierra Club (SC) (collectively, “MNS”) and Citizens Utility  
7           Board of Michigan (CUB).

8     **Q.    What is the purpose of your testimony?**

9     A.    I am testifying on behalf of MNS and CUB to support the settlement agreement in this  
10          case.<sup>1</sup>

11    **Q.    Are you sponsoring any exhibits?**

12    A.    No.

13    **Q.    Please summarize your opinions regarding the settlement agreement.**

14    A.    The settlement agreement is in the public interest; represents a fair and reasonable  
15          resolution of this case; and is supported by substantial evidence. The settlement preserves  
16          the most beneficial aspects of Consumers’ Proposed Course of Action, including the  
17          retirement of the entire Campbell plant and the permanent exit from coal generation in  
18          2025; as well as the solar ramp-up and annual competitive solicitations for solar generation.

---

<sup>1</sup> Case No. U-21090, Settlement Agreement filed April 20, 2022.

1 The settlement also improves upon Consumers' initially-filed PCA by:

- 2 • Eliminating the purchase of certain gas plants from Consumers' affiliate CMS  
3 Enterprises;
- 4 • Providing for competitive solicitation of Power Purchase Agreements to backfill  
5 the retiring Campbell capacity, including a tranche of dispatchable, non-  
6 intermittent generation and a tranche of clean capacity (which includes battery  
7 storage resources);
- 8 • Maintaining Karn units 3-4 in operation to support resource adequacy;
- 9 • Reducing the return on equity for the proposed regulatory asset for the retiring  
10 Campbell plant;
- 11 • Providing additional support from Company shareholders to low-income customer  
12 bill assistance programs;
- 13 • Substantially maintaining the 50/50 procurement terms from the settlement in Case  
14 No. U-20165;
- 15 • Maintaining the Financial Compensation Mechanism methodology from the  
16 settlement in Case No. U-20165;
- 17 • Requiring further evaluation of transmission options to improve reliability and  
18 facilitate economic power imports;
- 19 • Advancing battery storage investments;
- 20 • Improving future analysis of line losses and avoided transmission and distribution  
21 costs in the evaluation of distributed resources, including residential demand  
22 response;

- 1           • Requiring environmental justice analysis in Consumers' next IRP;
- 2           • Providing for public filing of community transition plans for the Campbell and
- 3           Karn sites; and
- 4           • Addressing issues under the Public Utility Regulatory Policies Act (PURPA) to the
- 5           satisfaction of the parties who engaged on those issues.

6           The improvements to the PCA reflected in the settlement agreement resulted from  
7           extensive, arms-length negotiations between Consumers and the parties, and the settlement  
8           agreement is supported by the vast majority of the parties in this case. For these reasons,  
9           it is my opinion that the settlement is in the best interest of customers and the environment,  
10          and I wholeheartedly recommend that the Commission approve it.

11    **II. OVERVIEW OF CONSUMERS' INITIAL PROPOSALS IN THIS CASE**

12    **Q. Please summarize the resource portfolio presented in Consumers' initial PCA in this**  
13    **case.**

14    **A.** The PCA described in Consumers Energy's direct case included the following resource  
15    elements:

- 16           • Retire Karn units 3 and 4, which are oil/gas peakers, in May 2023;
- 17           • Retire coal-fired Campbell units 1, 2, and 3 in May 2025;
- 18           • Purchase the New Covert Generating Facility, a natural gas-fired plant, in May
- 19           2023;
- 20           • Purchase three gas plants owned by Consumers' affiliate, CMS Enterprises
- 21           Company – Dearborn Industrial Generation (DIG), Kalamazoo, and Livingston –
- 22           in May 2025;

- 1           • Continue procuring solar resources via annual competitive solicitations, with  
2           increases in projected utility-scale solar deployment throughout the 2020s and  
3           2030s;
- 4           • Slow development of battery storage projects, with the first battery resources  
5           coming online in 2030;
- 6           • Make modest adjustments in Consumers' projected Energy Waste Reduction,  
7           Demand Response, and Conservation Voltage Reduction programs; and
- 8           • Pursue no new transmission projects or agreements to secure power imports from  
9           outside MISO Zone 7.

10 **Q. Please summarize the principal financial requests that Consumers made in its direct**  
11 **case.**

12 **A.** Apart from the gas plant acquisition costs, Consumers made two significant financial  
13 requests in its initial case.

14 First, Consumers proposed to establish a \$1.5 billion regulatory asset for the unrecovered  
15 book balances of the Campbell plant and Karn units 3-4. Consumers also proposed to  
16 recover that asset through conventional ratemaking over the previously planned remaining  
17 life of the units, with recovery of depreciation expense and pre-tax weighted average cost  
18 of capital, or WACC, including return on equity.

19 Second, Consumers proposed to change the method by which its PPA Financial  
20 Compensation Mechanism, or FCM, is calculated. The settlement in Consumers' last IRP  
21 case, U-20165, provided the Company with an FCM calculated by multiplying the PPA

1 payments by Consumers' after-tax WACC using its total capital structure. In this case,  
2 Consumers proposed to increase the FCM by multiplying the PPA payments by  
3 Consumers' pre-tax WACC using its permanent capital structure. Using pre-tax WACC  
4 instead of after-tax WACC and using permanent capital structure instead of total capital  
5 structure would have increased Consumers' current PPA incentive by almost 50%.

6 **Q. Did Consumers propose changing its solar procurement practices?**

7 **A.** Yes. The most significant proposed change was to the allocation between Company-owned  
8 and PPA solar projects. In the settlement of Case No. U-20165, Consumers agreed to  
9 acquire at least 50% of its solar capacity acquired via PPAs and no more than 50% from  
10 company-owned projects or build-transfer agreements. In this case, the Company proposed  
11 to reverse that allocation and acquire at least 50% from company-owned resources and no  
12 more than 50% via PPAs.

13 **III. REASONABLENESS OF THE SETTLEMENT AGREEMENT**

14 **Q. What does the settlement provide regarding the Campbell plant?**

15 **A.** In paragraph 4(ii) of the settlement, the parties agree that Campbell units 1, 2, and 3 will  
16 retire on or before May 31, 2025.

17 **Q. In your opinion, is retiring the Campbell plant a reasonable and beneficial  
18 settlement term?**

19 **A.** Yes. First it should be noted that no party in this case opposed retirement of Campbell units  
20 1 and 2. The Proposal for Decision (PFD) in this case also recommended approval of those  
21 retirements.

1 Further, retiring the entire Campbell plant will benefit both customers and the  
2 environment and is therefore in the public interest. After Karn 1 and 2 retire in 2023,  
3 Campbell 1-3 will be the last remaining coal units in Consumers' portfolio. The Campbell  
4 plant has a greater carbon impact than any other resource owned by the Company, and its  
5 retirement is critical to meeting state and federal climate goals, including the Michigan  
6 Healthy Climate Plan.<sup>2</sup> Because the Campbell plant emits other pollutants, such as SO<sub>2</sub>,  
7 NO<sub>x</sub>, and particulate matter, retiring Campbell is likely to also have health benefits in  
8 addition to those from reducing the Company's carbon output.

9 Extensive modeling conducted by Consumers and by MNS in this case demonstrated that  
10 retiring Campbell in 2025 is economic for customers. MNS witnesses Tyler Comings and  
11 Casey Roberts also explained that Campbell's continued operation poses regulatory risks  
12 due to Steam Electric Effluent Guidelines (SEEG) requirements and potential carbon costs.  
13 And witness Comings noted that retiring Campbell in 2025 will save customers more than  
14 \$150 million of avoidable capital expenditures. In proposing Campbell's retirement, the  
15 Company also cited community and worker benefits of accelerated retirement over  
16 continued operation. The testimony, exhibits, and modeling regarding these issues provide  
17 substantial evidence to support the Campbell plant retirement.

18 **Q. Please explain why Campbell's 2025 retirement is important for meeting the**  
19 **Michigan Healthy Climate Plan goals.**

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<sup>2</sup> Available at <https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbffa&hash=99437BF2709B9B3471D16FC1EC692588>, last checked May 6, 2022.

1    **A.**    Governor Whitmer’s Executive Directive, which initiated development of the Michigan  
2            Healthy Climate Plan, directed that the plan should result in 26-28% reduction in economy-  
3            wide greenhouse gas emissions from 2005 to 2025.<sup>3</sup> The following table displays  
4            Michigan’s GHG emissions in 2005 and the associated goals of the Michigan Healthy  
5            Climate Plan as I compiled them from reports by the US Energy Information  
6            Administration:<sup>4</sup>

Michigan Energy GHG Emissions 2005 (million metric tons CO2 Equivalent)	Residential Sector	Commercial Sector	Industrial Sector	Transportation Sector	Electric Power Sector	All Energy Sectors
Coal	0.0	0.3	7.3	0.0	67.8	75.4
Petroleum Products	4.6	0.9	5.8	53.8	0.8	65.9
Natural Gas	19.3	9.4	12.0	1.5	7.0	49.2
Total Energy-Related	23.9	10.6	25.1	55.3	75.6	190.5
Non-Energy 2002 GHG Emissions						29.3
Total 2005 GHG Emissions						219.8
NDC Goal 2025	26% Reduction from 2005					162.7
NDC Goal 2030	50% reduction from 2005					109.9
Whitmer Goal 2050	Net Zero by 2050					0.0
Energy Emissions Goal 2025	Assume 0% reductions in non-energy GHG emissions since 2005					133.4
Energy Emissions Goal 2030	Assume 25% reduction in non-energy GHG emissions since 2005					88.0
Energy Emissions Goal 2050	Assume elimination or offsets by 2050					0.0

7  
8            2019 is the most recent full compilation of similar data available from EIA. As of 2019,  
9            the corresponding emissions were as shown in the following table:

<sup>3</sup> Executive Directive 2020-10 affirmed this goal that she first adopted in Executive Directive 2019-12.

<sup>4</sup> State Carbon Dioxide Emissions Data - U.S. Energy Information Administration (EIA), available at <https://www.eia.gov/environment/emissions/state/>, last checked May 6, 2022.

Michigan Energy GHG Emissions 2019 (million metric tons CO2 Equivalent)	Residential Sector	Commercial Sector	Industrial Sector	Transportation Sector	Electric Power Sector	All Energy Sectors
Coal	0.0	0.0	4.0	0.0	44.2	48.2
Petroleum Products	3.5	1.5	6.2	50.5	0.6	62.2
Natural Gas	20.2	11.1	10.6	0.0	16.8	58.7
Total Energy-Related	23.7	12.6	20.8	50.5	61.6	169.2
Energy Emissions Reduction Needed by 2025						35.8
Energy Emissions Reduction Needed by 2030						81.2

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Since policy and economic trends related to the residential, commercial, industrial, and transportation sectors have not obviously caused a change in emissions trends in these sectors, I used those trends to project a similar table for 2025. In addition, I used EPA’s facility-level GHG emissions inventory<sup>5</sup> to identify 2019 GHG emissions from Michigan power plants that have since retired or been committed to retire by 2025, including the Campbell plant, and assumed that reduction from Electric Power Sector emissions. That forecast provides the following comparable table:

2025 GHG Emissions Reductions (million metric tons CO2 equivalent)	Residential Sector	Commercial Sector	Industrial Sector	Transportation Sector	Electric Power Sector	All Energy Sectors
Replace Coal Generation with Clean Generation					-17.8	
EV Sales Ramp to 100% by 2035				-3.5		
Accelerate Heating Efficiency & Electrification to 3.5%/yr	-5.6	-2.6	-4.1			
2025 Remaining Energy-Related Emissions	18.1	9.9	16.7	47.0	43.8	135.5
2025 Gap						2.1

9

<sup>5</sup> EPA Facility Level GHG Emissions Data, available at: <https://ghgdata.epa.gov/ghgp/main.do#/facility/>, last checked May 9, 2022.

1 Assuming the Campbell retirement and no new gas-fueled generation, there is a gap of 2.1  
2 million metric tons CO<sub>2</sub> equivalent (MMT CO<sub>2</sub>eq) between the 2025 goal of the Michigan  
3 Healthy Climate Plan and what is likely to be achieved. Since the Campbell plant annual  
4 emissions are approximately 8.285 MMT CO<sub>2</sub>eq, it is clearly not possible to meet the 2025  
5 goal of the Michigan Healthy Climate Plan without the retirement of the Campbell plant  
6 by 2025. The retirement of Campbell is therefore critical to meeting the Climate Plan's  
7 goal.

8 Further, the Michigan Healthy Climate Plan calls for the retirement of all coal generation  
9 by 2030, which would necessarily include the Campbell units.

10 **Q. What does the settlement provide regarding solar generation?**

11 **A.** By approving the PCA except as modified in the settlement agreement, paragraph 1 of the  
12 agreement approves Consumers' continued ramp-up of solar resources – an initiative first  
13 approved as part of Consumers' 2018 IRP. In the 2018 case, the Commission approved a  
14 plan that included approximately 5 GW nameplate of new solar resources in the 2020s. In  
15 this case, Consumers proposed to continue those additions and also procure an additional  
16 2 GW of solar in the 2030s above the levels included in the 2018 IRP. Paragraph 8 of the  
17 settlement agreement provides that Consumers will continue to utilize annual competitive  
18 solicitations to procure these solar resources.

19 **Q. In your opinion, is approval of Consumers' solar additions a reasonable and**  
20 **beneficial settlement term?**

21 **A.** Yes. In approving the settlement in U-20165, the Commission recognized that Consumers

1 Energy's planned solar ramp-up was both groundbreaking and environmentally beneficial.  
2 The Commission also endorsed the use of the annual solicitations to promote competition  
3 that would keep costs down and benefit customers. These public interest benefits, which  
4 the Commission has already recognized, will continue with the new settlement.

5 **Q. What does the settlement provide for regarding the acquisition of gas plants?**

6 **A.** First, the parties agree at paragraph 2 to Consumers' acquisition of the Covert plant, and  
7 that the purchase costs for that plant of \$815 million are reasonable and prudent.

8 Second, the parties agree at paragraph 2 that Consumers will not obtain ownership of the  
9 three CMS plants: DIG, Livingston, and Kalamazoo.

10 **Q. In your opinion, are the settlement terms regarding the acquisition of gas plants**  
11 **reasonable and beneficial?**

12 **A.** Yes. With respect to Covert, no party opposed Consumers' acquisition of that plant, and  
13 the PFD recommended approving it. As testimony by both Staff and Consumers pointed  
14 out, because Covert is currently in PJM, Consumers' acquisition of Covert will add 1,114  
15 Zonal Resource Credits or ZRCs to MISO Zone 7. That action will support reliability for  
16 Consumers as well as overall resource adequacy for Zone 7. For these reasons, acquisition  
17 of Covert is both in the public interest from a reliability and resource adequacy standpoint,  
18 and it is supported by substantial evidence in the record of this case.

19 Consumers' agreement not to acquire the CMS plants is also in the public interest and  
20 supported by substantial evidence. The record in this case showed myriad concerns  
21 regarding the CMS acquisitions – including issues with respect to affiliate transactions; the

1 nature of the gas plant RFP solicitation that led to the proposed purchase of these plants;  
2 and related issues. Staff, the Attorney General, and MNS all submitted substantial  
3 testimony and exhibits regarding these issues, and the hearing included substantial live  
4 testimony concerning them as well. In addition, parties including MNS, the Clean Energy  
5 Organizations (CEOs), and the Great Lakes Renewable Energy Association also provided  
6 evidence concerning certain risks associated with acquisition of those plants. Based on all  
7 of this evidence, the PFD also recommended against acquisition of the CMS plants.

8 Consumers has since come up with prudent plans to backfill capacity from retiring  
9 Campbell units by other means. I describe those plans next. Finally, it is worth noting that  
10 Staff supported in testimony Consumers' acquisition of Covert but not the CMS plants.  
11 The acquisition of some, but not all, of the assets Consumers sought to acquire is a self-  
12 evidently reasonable compromise.

13 **Q. Which resources would replace Campbell's retiring capacity?**

14 **A.** Under the settlement, Campbell's capacity will be replaced by a mix of resources. First,  
15 acquisition of the Covert plant will provide Consumers most of the energy and capacity  
16 currently provided by Campbell. Second, the settlement includes a one-time solicitation  
17 for PPAs that will provide up to 700 ZRCs of energy and capacity. These PPAs would be  
18 added to the Company's resource portfolio in the 2025 Planning Year – coinciding with  
19 the retirement of Campbell.

1 **Q. Please describe the one-time solicitation of capacity and energy for the 2025**  
2 **Planning Year.**

3 **A.** In paragraph 6 of the settlement, the parties agree that Consumers will issue a one-time  
4 competitive solicitation for PPAs to begin in PY 2025. The solicitation will contain two  
5 tranches. The first tranche will seek up to 500 ZRCs of energy and capacity for up to 10  
6 years from dispatchable, non-intermittent generation. The second tranche will seek up to  
7 200 ZRCs of energy and capacity for up to 25 years from clean energy resources (including  
8 battery storage).

9 **Q. In your opinion, is the one-time competitive solicitation a reasonable and beneficial**  
10 **settlement term?**

11 **A.** Yes. The first tranche will provide energy and capacity of similar characteristics to what  
12 Consumers sought via the proposal to acquire the CMS plants. However, soliciting 10-year  
13 PPAs instead of acquiring affiliate assets planned to remain in rate base until 2040 will  
14 reduce risks to customers. Further, a solicitation for PPAs addresses one of the issues with  
15 the earlier RFP identified by parties and the PFD, which was that the earlier RFP only  
16 sought assets for purchase. Obtaining power via PPAs also addresses some of the other  
17 risks identified in the record, namely, those related to environmental permitting and fixed  
18 operating and maintenance expenses. Finally, the PPA approach is consistent with MNS  
19 modeling plans 1 and 3 discussed by witnesses George Evans and Tyler Comings. Those  
20 plans proposed using capacity purchases as part of lower-cost portfolios that retired

1 Campbell 3 without buying most or all of the CMS plants.

2 The second tranche is also beneficial to the public interest and supported by substantial  
3 evidence. It will provide additional clean energy resources for Consumers' portfolio, with  
4 the attendant benefits I discussed earlier in my testimony. It is also consistent with my  
5 testimony that Consumers should solicit for up to 750 MW of solar resources per year  
6 rather than 500 MW – a recommendation the PFD also adopted.

7 **Q. What does the settlement provide regarding Karn units 3-4?**

8 **A.** Paragraph 4(i) of the settlement provides that Karn units 3-4 will not retire in 2023 but  
9 instead will continue operating and retire on or before their previously planned retirement  
10 date of May 31, 2031, absent extraordinary circumstances.

11 **Q. In your opinion, is the Karn retirement date a reasonable and beneficial settlement**  
12 **term?**

13 **A.** Yes. Karn 3-4 are large peaking units already owned by Consumers. They provide  
14 substantial capacity but operate infrequently. Continuing to operate Karn 3-4 supports  
15 Consumers' attainment of planning reserve margin requirements by maintaining more than  
16 780 ZRCs in the Company's portfolio. It also supports resource adequacy in Zone 7, for  
17 the same reason. Public health and climate impacts from Karn 3-4 are minor because the  
18 units operate so infrequently; in recent years their capacity factor has been substantially  
19 less than 5%. Keeping Karn 3-4 in operation also removes its unrecovered net book value  
20 from the total balance of the regulatory asset that Consumers seeks, which will now be  
21 limited to the balance for the Campbell plant, lowering the costs of the regulatory asset for

1 customers.

2 **Q. What does the settlement provide regarding Consumers' request for the regulatory**  
3 **asset you just mentioned?**

4 **A.** In paragraph 5 of the settlement, the parties agree that after retirement of the Campbell  
5 plant in 2025, the return on equity used to calculate the WACC for the regulatory asset will  
6 be 9.0%.

7 **Q. In your opinion, is this regulatory asset provision a reasonable and beneficial**  
8 **settlement term?**

9 **A.** Yes. Consumers has taken a very firm position that it will not retire Campbell in 2025  
10 without being able to recover a return of and on the unrecovered balance. Therefore, it was  
11 necessary for the other parties to agree with a regulatory asset based on WACC for this  
12 settlement to occur and to facilitate Consumers' permanent exit from coal generation three  
13 years from now. On the other hand, setting the ROE at 9.0% for the calculation of the  
14 WACC on the regulatory asset is a significant compromise for Consumers, as that figure  
15 is substantially lower than the authorized ROE of 9.9% that the Commission approved in  
16 Consumers Energy's last electric rate case, U-20963. In addition, it is my understanding  
17 that the Attorney General negotiated the low-income bill assistance provision I describe  
18 next in tandem with the compromise on the regulatory asset, which further balances the  
19 burdens and benefits of this important financial component of the agreement.

1 **Q. What does the settlement provide regarding support from Company shareholders to**  
2 **low-income customer bill assistance programs?**

3 **A.** Consumers agreed in paragraph 13 of the settlement to donate funds to its low-income bill  
4 assistance programs. These donated funds will not be recovered in rates. Consumers will  
5 donate \$5 million in 2022 and \$2 million per year for the rest of the term of the regulatory  
6 asset for the Campbell plant. Consumers will consult with the Attorney General and Staff  
7 on the recipient low-income fund, and will provide an annual report to the Commission.

8 **Q. In your opinion, are the low-income assistance donations a beneficial settlement**  
9 **term?**

10 **A.** Yes. The need for additional low-income customer bill assistance has been demonstrated  
11 both in recent Consumers electric rate cases and in recent Consumers EWR cases, and  
12 recognized by the Commission in a variety of orders.<sup>6</sup> Prohibiting recovery of these funds  
13 in rates will ensure that they come from shareholders, which is a reasonable component of  
14 the overall compromise on the regulatory asset and ROE.

15 **Q. What does the settlement provide regarding the allocation of future solar**  
16 **procurements?**

17 **A.** Paragraph 9 of the settlement requires Consumers to use commercially reasonable efforts  
18 to maintain the 50/50 split between owned resources and PPAs for new solar procurements

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<sup>6</sup> See for example Case No. U-20963, December 22, 2021 Order, pp. 402-403 (agreeing “that a COSS with a low-income customer subclass may be beneficial and recommends the company include a low-income customer subclass in the COSS for the EAAC in Case No. U-20757[.]”); Case No. U-20875, March 17, 2022 Order Approving Settlement Agreement.

1 that was first approved in the U-20165 settlement. This provision creates an absolute cap  
2 of 60% on capacity that Consumers acquires for ownership in any annual solicitation, while  
3 setting no cap on the amount of new solar the Company may acquire via PPA. The term  
4 also maintains the bar on Consumers affiliates participating in the PPA portion of the  
5 solicitations.

6 **Q. In your opinion, is continuing the 50/50 split a reasonable and beneficial settlement**  
7 **term?**

8 **A.** Yes. The Commission found this allocation reasonable and in the public interest in Case  
9 No. U-20165 and this term maintains the essential components of that agreement. It  
10 promotes competition among third-party developers which reduces customer costs, and it  
11 helps support the solar industry in Michigan. This term represents a substantial compromise  
12 by Consumers, which had sought in this case to eliminate a maximum amount of solar it  
13 could procure for Company ownership. This provision is also consistent with the PFD  
14 recommendation on this issue.

15 **Q. What does the settlement provide regarding the Financial Compensation**  
16 **Mechanism?**

17 **A.** The settlement provides at paragraph 10 for an extension of the FCM approved in Case  
18 No. U-20165. The method for calculating the FCM will remain the same as approved in  
19 that case, using after-tax WACC and total capital structure. The FCM will not be applied  
20 to PPA amendments, PURPA PPAs, Voluntary Green Pricing PPAs, or PPAs executed  
21 under Consumers' renewable energy plan.

1 **Q. In your opinion, is the FCM a reasonable and beneficial settlement term?**

2 **A.** Yes. Consumers has substantially changed its business model by agreeing to shift its  
3 resource portfolio away from coal generation and toward solar generation, and by agreeing  
4 to procure the solar generation via competitive solicitations under which half of that  
5 capacity will be in the form of PPAs. An FCM is a reasonable incentive for the Commission  
6 to authorize under such circumstances. I supported the FCM under these terms in both U-  
7 20165 and this case for those reasons. The Commission approved the FCM in Case No. U-  
8 20165 over vigorous objection of a small minority of parties, and the Commission's  
9 reasoning in that case applies equally in this one. Further, Consumers has compromised on  
10 the methodology for calculating the FCM by using after-tax WACC and total capital  
11 structure rather than pre-tax WACC and permanent capital structure as the Company  
12 requested in this case. The calculation methodology is also supported by my testimony in  
13 this case.

14 **Q. What does the settlement provide regarding transmission analysis?**

15 **A.** Paragraph 16 of the settlement states that the parties agree in Consumers' next IRP to  
16 consider how transmission investments can improve reliability and access to economic  
17 sources of power from areas outside Zone 7.

18 **Q. In your opinion, is the transmission provision a reasonable and beneficial settlement**  
19 **term?**

20 **A.** Yes. MNS witness Jay Caspary described the importance of transmission for both  
21 reliability and economics in his direct testimony in this case. The PFD found that

1 Consumers' transmission analysis in this case was deficient and did not meet the terms of  
2 the settlement agreement in U-21065. Consumers' commitment to address transmission  
3 analysis further in its next IRP will maintain focus on this issue going forward.

4 **Q. What does the settlement provide regarding battery storage investments?**

5 **A.** The parties agree to approval of a battery deployment program in paragraph 3 of the  
6 settlement agreement. Consumers proposed in rebuttal testimony to advance investment in  
7 75 MW of battery storage resources. The settlement reserves approval of the costs of the  
8 program to future electric rate cases.

9 **Q. In your opinion, is the battery storage program a reasonable and beneficial**  
10 **settlement term?**

11 **A.** Yes. Consumers made the battery proposal in response to testimony from Staff, MNS, and  
12 other parties that called for acceleration of battery storage investments as part of  
13 Consumers' resource portfolio for this IRP. The battery deployment will provide another  
14 clean energy resource to bolster Consumers' maintenance of its PRMR and support  
15 resource adequacy in Zone 7. It is also worth noting that the clean energy tranche of the  
16 one-time solicitation (paragraph 6(b)(ii)) may similarly lead to the development of new  
17 battery storage resources within Zone 7.

1 **Q. What does the settlement provide regarding collection and analysis of line loss data**  
2 **and avoided transmission and distribution costs in the evaluation of distributed**  
3 **resources?**

4 **A.** Consumers agrees in paragraph 14 of the settlement to collect further data on marginal line  
5 losses and to include marginal line losses and avoided transmission and distribution (T&D)  
6 costs in the evaluation of all distributed resources, including residential demand response,  
7 for its next IRP.

8 **Q. In your opinion, is the line loss and avoided T&D provision a reasonable and**  
9 **beneficial settlement term?**

10 **A.** Yes. This term is based on recommendations by CUB witness David Gard and MNS  
11 witness Chris Neme. Both of these witnesses explained the importance of these issues to  
12 the evaluation of EWR potential and DR potential for future IRPs. Consumers agreed to  
13 some but not all of their recommendations in rebuttal testimony, and has reached further  
14 agreement via this settlement term.

15 **Q. What does the settlement provide regarding environmental justice and community**  
16 **outreach?**

17 **A.** Paragraphs 17 and 18 of the settlement contain detailed provisions regarding environmental  
18 justice analysis and community outreach for Consumers' next IRP.

1 **Q. In your opinion, are the environmental justice and community outreach provisions**  
2 **reasonable and beneficial settlement terms?**

3 **A.** Yes. The CEOs and Urban Core Collective sought measures like these in their testimony  
4 in this case. The environmental justice analysis will provide vital information regarding the  
5 people and communities who bear disproportionate impacts of electric generation activities  
6 – information that has been lacking in Michigan IRP cases up until now. The community  
7 outreach provisions are important steps toward facilitating greater awareness and  
8 participation by people and communities who are normally excluded by the nature of  
9 proceedings like these.

10 **Q. What does the settlement provide regarding community transition plans for the**  
11 **Campbell and Karn sites?**

12 **A.** Paragraph 7 of the settlement agreement requires Consumers to publicly file its community  
13 transition plans for the Campbell and Karn sites.

14 **Q. In your opinion, is the community transition plans provision a reasonable and**  
15 **beneficial settlement term?**

16 **A.** Yes. MNS witness Tyler Comings testified in this case regarding the need for these plans  
17 to be public.

18 **IV. CONCLUSION AND RECOMMENDATIONS**

19 **Q. What is your overall conclusion regarding the settlement agreement?**

20 **A.** The settlement agreement in this case continues and significantly extends the progress of  
21 the settlement in U-20165. The settlement approves a major step by Consumers to address

1 the climate crisis while providing numerous protections for customers from future costs  
2 and risks. It is comprehensive, detailed, thorough, and embodies the input of many parties  
3 to this case. It is supported by the great weight of the evidence in the record of this case  
4 and consistent with many of the findings and recommendations in the PFD. It is the product  
5 of extensive negotiations and represents reasonable compromises on many fronts. I  
6 recommend that the Commission approve it.

7 **Q. Does that complete your testimony?**

8 A. Yes.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) )  
Emergency Order: Midcontinent )  
Independent System Operator )  
(MISO) )  
\_\_\_\_\_ )

Order No. 202-26-16

Exhibit to  
Motion to Intervene and Request for Rehearing and Stay of  
Public Interest Organizations

# Exhibit 58

## MISO Tariff Module E-1



This Module E-1 provides mandatory requirements to be met by the Transmission Provider, Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity (LSE), or other Market Participants, to ensure access to deliverable, reliable and adequate Planning Resources to meet Coincident Peak Demand and Local Resource Zone Peak Demand requirements on the Transmission System. These requirements recognize and are complementary to the reliability mechanisms of the states and the Regional Entities (RE) within the Transmission Provider Region. Nothing in this Module E-1 affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy. The Resource Adequacy Requirements (RAR) in this Module E-1 are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction. To the extent that an LSE's Coincident Peak Demand is physically located within the Transmission Provider's Balancing Authority Area but is pseudo-tied out of the MISO Balancing Authority Area pursuant to the Transmission Provider's Business Practices Manuals (BPM), such Coincident Peak Demand is not subject to the RAR provisions if such Coincident Peak Demand is subject to another Balancing Authority Area's resource adequacy requirements. To accomplish these reliability requirements, Module E-1 includes provisions for: establishing Local Resource Zones and associated limits (*i.e.*, Capacity Import Limits (CIL) and Capacity Export Limits (CEL)); establishing Local Reliability Requirements (LRR); establishing Local Clearing Requirements (LCR); establishing External Resource Zones and associated limits (*i.e.*, Capacity Export Limits (CEL)); determining the Planning Reserve Margin; Coincident Peak Demand forecasting; Local Resource Zone Peak Demand forecasting; qualifying and quantifying Planning Resources; participation of Demand and Planning Resources in the Planning Resource

Auction process; settlement provisions; and Planning Resource performance requirements for each Season.

### **Establishment of Planning Reserve Margins**

The Transmission Provider will determine a Planning Reserve Margin (PRM) in terms of Unforced Capacity for each Season using analytical study methods described in Section 68A.2, provided that if a State Regulatory Authority establishes a PRM for its regulated entities that is higher or lower than the PRM determined by the Transmission Provider, then the State Regulatory Authority-established PRM will apply to the Coincident Peak Demand of LSEs under that state's jurisdiction.

### **Planning Reserve Margin Analysis**

The Transmission Provider shall perform a technical analysis on an annual basis to establish the PRM for each Season for the Transmission Provider Region and the Transmission Provider will publish the results by November 1 preceding the applicable Planning Year. The PRM analysis shall be consistent with Good Utility Practice and the reliability requirements of the REs and the applicable states in the Transmission Provider Region. The PRM analysis shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources; Generator Planned Outages; expected performance of Demand Response Resources (DRR), Load Modifying Resources (LMR), and Energy Efficiency Resources; load forecast uncertainty; and the Transmission System's import and export capability with external systems. The Transmission Provider annually will calculate and publish on its website the estimated PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning, without establishing any enforceable specific planning reserve requirements.

### **Loss of Load Expectation Analysis**

The Transmission Provider shall coordinate with Market Participants to determine the appropriate PRM for the applicable Season in the Planning Year based upon the probabilistic analysis of being able to reliably serve the Transmission Provider Region's Demand for the applicable Season in the Planning Year. This probabilistic analysis shall use a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations within the Transmission Provider Region.

The following process will be utilized to determine the minimum PRM requirement for each Season in the Planning Year using the LOLE analysis. First, an LOLE analysis for the Planning Year will be conducted such that the LOLE for the Planning Year is one (1) day in ten (10) years, or 0.1 day per year, by either adding or removing capacity. If the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year. If the LOLE for a Season is equal to or greater than 0.01 day per year, the minimum PRM requirement for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year, an additional LOLE analysis will be performed to determine minimum PRM requirement for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01.

The minimum amount of capacity above Coincident Peak Demand in the Transmission Provider Region required to meet the reliability criteria will be used to establish the PRM for each Season.

The PRM will be established as a requirement in terms of the total Unforced Capacity for the Transmission Provider Region.

No later than September 1st of the year prior to a Planning Year, the Transmission Provider will, as necessary, develop new Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within the Transmission Provider Region to reliably meet Demand and LOLE requirements. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of LOLE studies; (5) the relative size of LRZs; and (6) natural geographic boundaries such as lakes and rivers. The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region based upon the preceding factors, including but not limited to, significant changes in membership, the Transmission System, and/or Resources.

An External Resource Zone (ERZ) will be created for each external Balancing Authority that has External Resources qualifying as Planning Resources, excluding those Balancing Authorities with only Coordinating Owner resources that are qualified to obtain local credit and/or Border External Resources.

### **Establishment of SRRZs, SRECs and SRICs**

The Transmission Provider will establish and publish, on the Transmission Provider's public website, SRRZs, SRECs and SRICs for each Season as soon as practical but no later than the first business day of March for the following Planning Year. To calculate the SRECs and SRICs, the Transmission Provider will determine the transfer limit between SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

Next, the Transmission Provider will then complete a feasibility analysis in accordance with the Resource Adequacy Business Practices Manual to review operational events from each Coincident Peak Demand hour during the previous Planning Year, and forecasted expected conditions for each Season in the upcoming Planning Year, to determine if a further reduction to the transfer limit is warranted for reliability. If such a reduction is necessary, the Transmission Provider will reduce the regional directional transfer limit, as appropriate. The Transmission Provider will then subtract the sum of Firm Transmission Service Reservations on the MISO OASIS that utilize the contract path between SRRZs and are exporting from or wheeling through the Transmission Provider's Balancing Authority for the applicable Season in the Planning Year. This difference determines the SREC and SRIC to be utilized for the applicable Season in the Planning Year.

Prior to publishing the SRRZs, SRECs, and SRICs on its public website, Transmission Provider will present the feasibility analysis and resulting SREC and SRIC calculation to stakeholders.

### **Establishment of CIL and CEL Limits**

On or before November 1st of each year, the Transmission Provider will determine preliminary values for the CIL and CEL for each of the LRZs for each Season in the following Planning Year by considering factors, including but not limited to, the following elements: (1) existing and planned Transmission System and Planning Resource additions; (2) transmission import and export capability; and (3) applicable NERC contingencies. To determine the CIL and CEL for each LRZ, the Transmission Provider will use models which contain the physical location of Load and Planning Resources for each Season. Generator output will be assigned to LRZs or ERZs consistent with the PRA representation of Planning Resources. Constraints that are identified as a result of determining the CIL and/or the CEL for each LRZ will be considered in the development of the MISO Transmission Expansion Plan (MTEP) in accordance with Attachment FF.

CIL will be equal to the Zonal Import Ability plus firm capacity commitments to non-MISO load. CEL will be equal to the Zonal Export Ability minus firm capacity commitments to non-MISO load.

The CIL and CEL values for each Season for each LRZ will be updated if needed prior to the Planning Resource Auction, but no later than eight (8) Business Days before the last Business Day in March, due to changes to firm capacity commitments from MISO resources to neighboring regions prior to the Planning Resource Auction.

MISO will determine the CEL for each Season for each ERZ no later than eight (8) Business Days before the last Business Day in March as equal to the ZRC quantity of the External Resources registered to participate in the PRA.

### **Establishment of Local Reliability Requirement**

By November 1st prior to a Planning Year, the Transmission Provider will establish a Local Reliability Requirement (LRR) metric for each LRZ to determine the quantity of Unforced Capacity needed for each Season, without consideration of the benefit of the LRZ's CIL. First, the LOLE analysis for the Planning Year will be conducted by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year. If the LOLE for a Season is equal to or greater than 0.01 day per year for the LRZ, the LRR for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year for the LRZ, an additional LOLE analysis will be performed to determine the LRR for that Season by adding a perfect negative unit with zero forced outage rate to that season until the LOLE in that Season reaches 0.01 day per year for the LRZ.

The Transmission Provider will model the location of Load and Planning Resources based on their representation in the Planning Resource Auction to determine the LRR for each LRZ. The minimum amount of capacity above the Local Resource Zone Peak Demand in the LRZ required to meet the reliability criteria will be used to establish the LRR for each Season.

The per unit LRR in each LRZ initially will be established as the ratio of the LRR over the Local Resource Zone Peak Demand modeled in the LOLE study. An LRZ's LRR shall be calculated by multiplying the per unit LRR for the LRZ times the forecasted Local Resource Zone Peak

Demand for each Season as provided by LSEs or EDCs, or as developed by the Transmission  
Provider, pursuant to Section 69A.1.

### **Establishment of Local Clearing Requirement**

The Local Clearing Requirement for each LRZ for each Season will be determined by subtracting Zonal Import Ability and controllable exports from the LRR, as set forth in the Resource Adequacy Business Practices Manual. Controllable exports are exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency. The LCR values will be updated if needed prior to the Planning Resource Auction due to changes in controllable exports.

### **Establishing Planning Reserve Margin Requirements**

- a. The Transmission Provider will establish Planning Reserve Margin Requirements (PRMR) for each Season for an LSE's Load within any given LRZ. The Initial PRMR will be determined by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by  $(1 + \text{Transmission Provider Region PRM})$ .
- b. The Transmission Provider will use the Transmission Provider Region PRM for the Initial PRMR calculation unless an alternate PRM is established by a State Regulatory Authority. In such event, the Transmission Provider will use the alternate PRM that a State Regulatory Authority has created for the geographic area in which the state has jurisdiction. The Transmission Provider will convert any State Regulatory Authority provided PRM to a comparable Unforced Capacity basis.

### **Calculation of Transmission Losses**

- a. The Transmission Provider shall calculate the LBA transmission loss percentages for each Season using the process described as follows:
  1. The Transmission Provider's State Estimator calculates transmission losses (MW) as part of the solution output process every five (5) minutes.
  2. The transmission losses (MW) are computed on all transmission lines and transformers by summing up real power at both ends for each transmission element (retaining the convention for flow direction) or as the difference in real power (without the sign convention for flow direction) for each State Estimator solution.
  3. The individual transmission losses (MW) for each element are summed to a total transmission values for each Local Balancing Authorities (LBA) level.
  4. These LBA transmission loss values are then integrated across each hour to calculate an hourly transmission loss value (MW) for each LBA.
  5. The total transmission loss value (MW) for each LBA will be the hourly integrated transmission losses value (MW) for the hour of the Coincident Peak Demand from the calendar year two years prior to the upcoming Planning Year.
  6. For the purposes of the Transmission Provider Region, the LBA transmission loss percentages are calculated as the total LBA transmission losses divided by the total LBA peak data at that MISO peak hour for each Season. For purposes of a Local Resource Zone, the LBA transmission loss percentages are calculated as the

total LBA transmission losses divided by the total LBA peak data at the LRZ peak hour for each Season.

- b. The Local Balancing Authority (LBA) transmission loss percentage shall apply to the LSE's applicable LBA Coincident Peak Demand and Local Resource Zone Peak Demand forecast to determine the LSE transmission losses. Behind-the-Meter-Generation Resources that are interconnected to the Transmission System shall be treated like other Resources with respect to transmission losses. Behind-the-Meter-Generation Resources and Distributed Energy Aggregated Resources that are not interconnected to the Transmission System, Demand Resources, and Energy Efficiency Resources shall be adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity of such resources by  $(1.0 + \text{the appropriate LBA transmission loss percentage})$ .

### **Marginal Reliability Impact (MRI) Curves**

- A. The following process will be used to determine the MRI Curves for the Transmission Provider Region for each Season of the upcoming Planning Year. The minimum PRM requirement for each Season established in the LOLE analysis, as described in Section 68A.2, will be the starting point. Then, for each Season, a perfect negative unit(s) with a capacity of at least 50MW and no more than 250MW, or perfect proxy unit(s) with a capacity of at least 50MW and no more than 250MW will be added to the model and the LOLE analysis will be performed. The capacity of both the perfect negative unit(s) and perfect proxy unit(s) will be of equal value. The change in EUE as a result of adding or removing capacity will be calculated. An additional unit(s) with the same capacity value will be added or removed in addition to the first increment or decrement and the LOLE analysis will be performed again. This process will be repeated until sufficient data is available to fit a curve that measures changes to EUE as MWs are added or removed from the minimum PRM requirement.
- B. The First Planning Area MRI Curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The following process will be used to determine the MRI Curves for the First Planning Area for each Season in the Planning Year. Assignment of LOLE risk across the Seasons will be the same as described in Section 68A.2 for the Planning Reserve Margin analysis. A minimum PRM requirement for the First Planning Area for each Season will be established through additional LOLE analysis in which the First Planning Area and Second Planning Area each have the same reliability target established for the

Transmission Provider Region as the starting point. After establishing the starting point, the MW quantity associated with the minimum PRM requirement in the Second Planning Area will be fixed, and capacity in the First Planning Area will then be added or removed to calculate changes to EUE in the First Planning Area.

- C. The Second Planning Area MRI curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The following process will be used to determine the MRI Curves for the Second Planning Area for each Season in the Planning Year. Assignment of LOLE risk across the Seasons will be the same as described in Section 68A.2 for the Planning Reserve Margin analysis. A minimum PRM requirement for the Second Planning Area for each Season will be established through additional LOLE analysis in which the First Planning Area and Second Planning Area each have the same reliability target established for the Transmission Provider Region as the starting point. After establishing the starting point, the MW quantity associated with the minimum PRM requirement in the First Planning Area will be fixed, and capacity in the Second Planning Area will then be added or removed to calculate changes to EUE in the Second Planning Area.

## **RAR Process**

Once the Transmission Provider has established the PRM, LCR, LRR, preliminary Capacity Import Limits and Capacity Export Limits and published such values on the Transmission Provider's website, then LSEs shall provide forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data for the Planning Year. For Retail Choice areas, the EDC shall provide, on behalf of LSEs within the EDC, forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data for the Planning Year to be used by the Transmission Provider. The Transmission Provider will then calculate each LSE's Initial PRMR for each Season. LSEs will meet their RAR obligation by: (i) submitting a Fixed Resource Adequacy Plan; (ii) submitting ZRCs for an RBDC Opt Out; (iii) Self-Scheduling ZRCs; (iv) purchasing ZRCs through the Planning Resource Auction process; and/or (v) paying the Capacity Deficiency Charge to meet a portion of their PRMR. LSEs that submit an RBDC Opt Out may not use any of the other options to satisfy their Final PRMR. LSEs not submitting an RBDC Opt Out may use one or more of all other available options, or any combination of available options, to satisfy their Initial or Final PRMR. The Transmission Provider will enforce the LCRs, final Capacity Import Limits and Capacity Export Limits for each LRZ, and Capacity Export Limits for each ERZ in the Planning Resource Auction. An ACP will be determined through the PRA process for each LRZ and ERZ for each Season and the ACP will be used to credit ZRCs that clear in the auction and to debit LSEs for the volume of their PRMR that is procured through the auction. Market Participants that own Planning Resources used to create ZRCs which clear in the PRA (or are identified in either a submitted Fixed Resource Adequacy Plan or an RBDC Opt Out) must meet the applicable performance requirements as described in sections 69A.3.9 and

69A.5. The Transmission Provider shall provide states, upon request, with relevant resource adequacy information as available, subject to the data confidentiality provisions in Section 38.9 of the Tariff.

### **Load Serving Entity Responsibilities**

- a. LSEs shall provide Coincident Peak Demand (and also, if available, Local Resource Zone Peak Demand forecasts) forecasts as specified in Section 69A.1.1b and will also be responsible for meeting their Final PRMR for each LRZ where they serve Load by submitting Fixed Resource Adequacy Plans, by Self-Scheduling ZRCs, by purchasing ZRCs through the PRA process, by submitting ZRCs for an RBDC Opt Out and/or by paying the Capacity Deficiency Charge.
- b. The Transmission Provider will use Coincident Peak Demand, Local Resource Zone Peak Demand, and Energy forecasts for each Season that are submitted by an EDC in combination with allocation procedures that are agreed to by the applicable LSEs. These procedures will allow the Transmission Provider to initially allocate appropriate portions of the total forecasted Coincident Peak Demand and Local Resource Zone Peak Demand to each LSE as applicable pursuant to 69A.1.2.1, and to re-assign ZRC-related charges caused by customer switching between suppliers to the appropriate LSE.
- c. All LSEs shall report to the Transmission Provider, through the MECT, whether such LSE will meet their PRMR for each LRZ for each Season in which the LSE serves Load by: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process; (iv) submitting an RBDC Opt Out; and/or, (v) paying the Capacity Deficiency Charge.

### **Forecasted Demand Identification**

a. The Demand forecasts required in Section 69A.1 shall include: (1) the Coincident Peak Demand within each LBA Area in the Transmission Provider Region for the upcoming Planning Year; (2) the monthly non-coincident peak Demand and net Energy for Load within each LBA Area, for the upcoming Planning Year and the following Planning Year; (3) the non-coincident peak Demand and net Energy for Load within each LBA Area, for each Season, for the eight Planning Years subsequent to the two for which monthly values are provided in (2); and (4) the available Local Resource Zone Peak Demand within each LBA Area in the Local Resource Zone for the upcoming Planning Year. All of these forecasts shall be submitted by November 1<sup>st</sup> prior to each Planning Year and shall be consistent with Good Utility Practice. Forecast providers shall use the MECT or other means described in the BPM for Resource Adequacy to submit the requisite information. Details regarding the items required in the Demand forecasts submittal are in the BPM for Resource Adequacy.

b. The supplied Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall include the Demand expected for the forecast time period (*e.g.* the Coincident Peak Demand hour) augmented to include the normal Demand from forecasted demand resources, whether registered or not registered with the Transmission Provider, including Demand from any retail demand side management programs and Demand behind a DEAR. Such forecasts shall include Demand that would have occurred but for the existence of Energy Efficiency Resources that have been in operation less than four (4) years. All submissions for such forecast values shall include distribution losses, but not transmission losses. The Transmission Provider will be responsible for the calculation of the applicable transmission losses for the forecasts provided

and for annually publishing such values for each LBA on its website by October 1, as specified in Section 68A.8 and the BPM for Resource Adequacy.

c. In order to assist with the development of the Coincident Peak Demand and Local Resource Zone Peak Demand forecasts, the Transmission Provider will make available the historical monthly peak hours for each of the four months June through September, since 2005, or as available, for the Transmission Provider Region and for each Local Resource Zone. On or before March 1<sup>st</sup> of each year, the Transmission Provider will review a sampling of submitted Demand forecast methodologies and inputs to ensure accuracy and consistency, in accordance with the BPM for Resource Adequacy. If the Transmission Provider determines that the Demand forecast methodologies are inaccurate or inconsistent, the Transmission Provider shall work with the applicable LSEs to reconcile such issues. If reconciliation is not achieved, or if Local Resource Zone Peak Demand forecasts are not available, then the Transmission Provider will provide the required forecast values.

d. All Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall reflect a 50% probability that the Demand will not exceed the forecasted Demand for the relevant period.

e. Consistent with Section 69A.1.2.1, the EDC must provide both the Transmission Provider and the respective LSEs with each retail customer's peak load contribution ("PLC") in each Season, including transmission losses and PRM as determined by the Transmission Provider, in the EDC's service territory by December 15<sup>th</sup>. At least five (5) Business Days before January 15, LSEs must notify the EDC and the Transmission Provider if they disagree with the EDC calculated PLC value.

f. If an LSE knows it will gain a wholesale customer by the beginning of any Season in the next Planning Year, then that LSE may provide the Transmission Provider with the Coincident Peak Demand and the Local Resource Zone Peak Demand forecast for such acquired load by November 1. In all other cases, the existing Market Participant serving such wholesale customer shall provide the Transmission Provider by November 1<sup>st</sup> with the Market Participant's forecast of the wholesale customer's Coincident Peak Demand and Local Resource Zone Peak Demand.

**Accounting for Total Demand Forecasts Given Wholesale and Retail Load Switching**

- a. On or before January 15<sup>th</sup>, an EDC must notify the Transmission Provider through the MECT of the Initial PRMR for the LSE's proportion of the EDC's forecast Demand that it expects to serve on the 1<sup>st</sup> day of each Season in the next Planning Year. The LSE that is the provider of last resort ("POLR") for the EDC area in question will have the obligation to procure capacity for the required PRMR for the remaining Demand (*i.e.*, the remaining Demand is the EDC's forecast Coincident Peak Demand minus the sum of the LSE's allocated portion of forecast Coincident Peak Demand, identified as described above, in the EDC's service territory). The Transmission Provider will notify the POLRs of any remaining Initial PRMR within five (5) Business Days after January 15<sup>th</sup>.
- b. On or before January 15<sup>th</sup>, to account for wholesale customers that may switch LSEs during the next Planning Year, the PRMR will be met as follows: (1) if an LSE has responsibility to serve a wholesale load on the 1<sup>st</sup> day of any Season in of the next Planning Year, then such LSE shall have the obligation to procure the required PRMR for such load for such Season; (2) if no LSE has responsibility for serving a wholesale load on of the 1st day of any Season in of the next Planning Year, then the LSE with an obligation to serve such load on November 1 before the Planning Year, shall have the obligation to procure capacity for the required PRMR for each Season in the upcoming Planning Year for such load, provided that such LSE anticipates that the contract for wholesale load will be extended; or (3) if the LSE advises the Transmission Provider that the LSE will not serve the contract for wholesale load, then the customer for such wholesale load shall inform the Transmission Provider by January

30<sup>th</sup> of the name of the Market Participant that will be responsible for the PRMR obligation for such wholesale load.

### **Daily Assignment of Coincident Peak Demand Obligations**

- a. For those areas of service where an LSE's Coincident Peak Demand forecast is included in the Coincident Peak Demand forecast submission of an EDC, the EDC will determine and report each LSE's portion of such Demand to the Transmission Provider, using the default method set forth in Section 69A.1.2.1.
- b. In a state that permits retail load switching, the Transmission Provider shall allocate resource capacity costs on a daily basis to LSEs by multiplying the Final PRMR associated with identified customers served by the LSE times the applicable zonal Auction Clearing Price less any zonal deliverability benefits plus any Local Clearing Requirement Charges for the Local Resource Zone where the load is located, consistent with Section 69A.1.2.1.
- c. In states where wholesale load may switch, the Transmission Provider shall allocate costs on a daily basis to LSEs. The LSE that acquires wholesale load will be charged for such load based upon the Final PRMR for the wholesale load's forecast Coincident Peak Demand times the applicable zonal Auction Clearing Price less any zonal deliverability benefits plus any Local Clearing Requirement Charges for the Local Resource Zone where the wholesale load is located.
- d. An LSE may challenge the EDC Demand forecast under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

### Default Method

- a. The method submitted by an EDC must describe in detail the procedures and data used to determine the assignment of the EDC's forecast Coincident Peak Demand to its retail customers, including those served by LSEs providing service within the EDC's area.
- b. EDC will assign a peak load contribution ("PLC") value to each retail customer, based on the most recent PLC values derived for each Season from each retail customer's Demand at the time of the Transmission Provider's peak Demand during each Season (*i.e.*, the Prior Seasonal Retail Customer Coincident Peak ("PSRCCP")). Retail customer peak demands should be increased to reflect any load reductions achieved and for which capacity credits are earned, either through retail programs or participation in wholesale markets (*e.g.* LMRs). In the aggregate, the PLCs determined by the EDC must equal the Initial PRMR that is calculated from the forecast Coincident Peak Demand provided by the EDC for each Season. This equality is achieved by multiplying each retail customer's demand at the time of the Transmission Provider's peak Demand during each Season prior to the Planning Year by the same adjustment factor, as shown in the equation below:

$$\sum_i \text{PLC}_i = \text{Initial PRMR}_{\text{EDC}}$$

$$\text{Factor} = \text{Initial PRMR}_{\text{EDC}} \div \sum_i \text{PSRCCP}_i$$

In other words, for each EDC, the sum of the individual retail customer (*i.e.*, *i*) PLC values must equal the EDC's Initial PRMR. In addition, a single value ("Factor") is defined as the ratio of the Initial PRMR for any EDC divided by the sum of all of the PSRCCP values for each of the EDC's retail customers. The EDC must use the same Factor in the following equation:

$$\text{PLC}_i = \text{Factor} \times \text{PSRCCP}_i \quad \forall i$$

Thus, for each EDC it must also be true that the PLC for any individual retail customer shall be equal to the product of that customer's PSRCCP times the same Factor identified in the second equation above. For the purposes of these equations, the following mathematical symbols are used: (1)  $\Sigma$  equals sum; (2)  $i$  equals individual retail customer, as in PLC  $_i$  or PSRCCP $_i$ ; and (3)  $\forall i$  equals for all  $i$ , as in: for each member of the set of retail customers.

c. The PSRCCP shall be adjusted (upward) to reflect any demand that was reduced during the Coincident Peak for each Season hour through the effect of a Load Modifying Resource, or through the effect of an Energy Efficiency Resource during the first four (4) full Planning Years of the EE Resource's existence. The Transmission Provider will provide to the EDC the amount of measured (or estimated if final settlement data is forthcoming) load reduction that occurred as a result of an ARC or LSE deploying a DRR, LMR or EDR following a Setpoint Instruction, Scheduling Instruction or EDR Dispatch Instruction during the Transmission Provider's Coincident Peak Demand.



### **Load Switching**

Beginning the first Calendar Day of each Season in the Planning Year, the EDC will be responsible for tracking the individual customer Final PRMR values transferred from the originally supplying LSE to the newly supplying LSE now responsible for resource adequacy commitments.

### **Forecasted Demand for FRP/FRS Agreements**

Full Responsibility Purchases/Sales (FRP/FRS) agreements are treated effectively like a transfer of Demand and all RAR obligations from one LSE to another Market Participant. A purchaser under an FRP/FRS agreement shall submit the forecasted Coincident Peak Demand and Local Resource Zone Peak Demand associated with such agreement to the Transmission Provider through the MECT for the applicable Planning Year. A seller under an FRP/FRS agreement is contractually obligated to comply with all of the RAR obligations for the transferred Demand during the Planning Year encompassing the planned Coincident Peak Demand. The purchaser under an FRP/FRS agreement no longer has the RAR obligations for the transferred Demand; provided however, that if the seller under an FRP/FRS agreement is not an LSE under the jurisdiction of the Transmission Provider, then the purchaser under the FRP/FRS agreement will remain responsible for any RAR obligations associated with the Demand transferred under the FRP/FRS agreement. A seller under an FRP/FRS agreement will be responsible for the transferred Demand to meet this additional obligation like it was their own Demand. If a seller and a purchaser under an FRP/FRS agreement cannot agree on whether a particular transaction is an FRP/FRS agreement, then either party may invoke the dispute resolution procedures in Section 12 of the Tariff.

### **Multiple Region Planning Resources**

If an LSE serves Demand both in the Transmission Provider Region and outside the Transmission Provider Region, then the LSE must separately satisfy its Final PRMR in all areas of the Transmission Provider Region. Compliance with RAR shall not affect an LSE's obligation to maintain distinct and separate amounts of resources to cover its applicable planning reserve obligation for the amount of Demand outside the Transmission Provider Region.

### **Capacity Tracking Tool**

To facilitate RAR, the Transmission Provider shall administer the MECT, a title tracking and registration tool that shall include the ability to enable Market Participants and LSEs to meet their RAR responsibilities.

### **Planning Resource Requirements**

Nothing herein shall infringe upon the requirement that LSEs comply with applicable state safety standards, planning reserve margins, or be subject to the enforcement thereof. If the Transmission Provider becomes aware that any Planning Resource fails to meet the requirements of this section, then the Transmission Provider shall promptly notify the Market Participant and specify the reasons for any such failure. Wherever possible, the Transmission Provider and the Market Participant will work in good faith to remedy deficiencies, if any, in meeting the Planning Resource requirements, through informal communications rather than Commission filings.

### **Capacity Resources**

As described below, a Generation Resource, External Resource, Demand Response Resource - Type II, Intermittent Generation, Dispatchable Intermittent Resource, Electric Storage Resource, or Hybrid Resource is eligible to become a Capacity Resource. The Transmission Provider will qualify a Capacity Resource for any applicable Season in the upcoming Planning Year, in accordance with processes specified in the BPM for Resource Adequacy. Electric Storage Resources can be Capacity Resources if they meet all the requirements as specified in the BPM for Resource Adequacy, including the requirement to be able to continuously discharge for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day, in accordance with the BPM for Resource Adequacy, provided that an Electric Storage Resource may de-rate its capacity in order to comply with this requirement.

## **Generation Resources that are not Dispatchable Intermittent Resources or Distributed**

### **Energy Aggregated Resources**

1. Generation Resources and Electric Storage Resources that are not Dispatchable Intermittent Resources or Distributed Energy Aggregated Resources are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights for the Resource by:
  - (a) registering such resource with the Transmission Provider as documented in the BPM for Market Registration;
  - (b) demonstrating GVTC capability for each Season in the Planning Year as established in the BPM for Resource Adequacy;
  - (c) submitting generator availability data (including, but not limited to, NERC Generation Availability Data System (GADS) information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy;
  - (d) by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.a.4; and
  - (e) demonstrating deliverability as described in Section 69A.3.1(g). All new Generation Resources and Electric Storage Resources that are not Dispatchable Intermittent Resources and Distributed Energy Aggregated Resources, or an existing Generation Resource and Electric Storage Resource that is not a Dispatchable Intermittent Resource and s Distributed Energy Aggregated Resource that has an increased installed capacity, shall submit their GVTC to the Transmission Provider prior to qualification, but no later

than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a Generation Resource and Electric Storage Resource that is not a Dispatchable Intermittent Resource (including a Generation Resource and Electric Storage Resource that has the status of Suspend pursuant to Section 38.2.7) and a Distributed Energy Aggregated Resource that has not completed GVTC testing by the deadlines provided in 69A.3.1.a.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA or in a FRAP (including through bilateral ZRC transactions), subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data based on GVTC is not required for a Generation Resource or Electric Storage Resource that is not a Dispatchable Intermittent Resource and a Distributed Energy Aggregated Resource and that is less than 10 MW if the Market Participant has never provided such data for such Resource. A Market Participant that begins reporting generator availability data based on GVTC for a Generation Resource or Electric Storage Resource that is not a Dispatchable Intermittent Resource and that is less than 10 MW must continue to report such data. A Generation Resource or Electric Storage Resource that has provisional Interconnection Service does not qualify as a Capacity Resource.

4. A Market Participant for a Generation Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning

Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Generation Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Generation Resource from utilizing the ICAP Deferral process as described in Section 69A.7.9.

### **Demand Response Resources – Type II**

1. Demand Response Resources – Type II backed by a Demand Resource are eligible to qualify as Capacity Resources. A Market Participant that possesses ownership or equivalent contractual rights in the DRR – Type II can register such resource as a Capacity Resource with the Transmission Provider for the upcoming Planning Year as documented in the BPM for Market Registration and by meeting the following requirements:
  - a. For an existing DRR – Type II that is a Capacity Resource, the Market Participant shall demonstrate capability and availability to reduce Demand in response to instructions from the Transmission Provider for each applicable Season and shall submit such data to the Transmission Provider no later than October 31 prior to such Planning Year unless the Transmission Provider has granted an extension, as established in the BPM for Resource Adequacy.
  - b. For a new DRR – Type II or for an existing DRR – Type II that has experienced an increase in its Capacity Rating, and that is backed by a Demand Resource, the Market Participant shall submit test data to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.
2. A Demand Response Resource – Type II that is backed by behind the meter generation is eligible to qualify as Capacity Resources. A Market Participant that possesses ownership or equivalent contractual rights in the DRR – Type II can register such resource as a Capacity Resource with the Transmission Provider for the upcoming Planning Year as

documented in the BPM for Market Registration and by meeting the following requirements:

- a. A Market Participant shall demonstrate GVTC capability of the DRR – Type II backed by behind the meter generation for each Season in the Planning Year as established in the BPM for Resource Adequacy;
- b. An existing DRR – Type II backed by behind the meter generation shall submit GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.b.4; and
- c. A Market Participant shall submit generator availability data (including, but not limited to, NERC Generation Availability Data System information) for the DRR – Type II backed by behind the meter generation into a database provided by the Transmission Provider.
- d. For a new DRR – Type II or an existing DRR – Type II that has an increased installed capacity, and that is backed by behind the meter generation, the Market Participant shall submit GVTC data to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.

### 3. Installed Capacity (ICAP) Deferral

If a Market Participant for a DRR – Type II has not completed GVTC testing by the deadlines provided in 69A.3.1.b.2, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs

from such capacity may be used in the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out (including through bilateral ZRC transactions) subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

4. Reporting generator availability data based on GVTC is not required for a DRR – Type II backed by behind the meter generation facility of less than 10 MW if the Market Participant has never provided such data for such behind the meter generation facility. A Market Participant that begins reporting generator availability data for behind the meter generation facility that is less than 10 MW based on GVTC must continue to report such data. A Demand Response Resource – Type II that has provisional Interconnection Service does not qualify as a Capacity Resource. In accordance with the qualification provisions in the BPM for Resource Adequacy, the Transmission Provider will qualify a Demand Response Resource – Type II for the applicable Season in the upcoming Planning Year.
5. A Market Participant for a DRR – Type II required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the DRR by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline.

Denial of an extension will not preclude the Market Participant for the DRR – Type II from utilizing the ICAP Deferral process as described in Section 69A.7.9.

**External Resources:**

1. External Resources, including those specified in Diversity Contracts and PPAs (which are subject to additional qualification requirements in section 69A.3.1.c.4), are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights in External Resources by: (a) registering such resources with the Transmission Provider as documented in the BPM for Resource Adequacy; (b) demonstrating GVTC capability for each Season that the resource will be registered in as established in the BPM for Resource Adequacy by providing operational data, and by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.c.5; (c) submitting generator availability data (including, but not limited to, NERC Generation Availability Data System information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy; (d) identifying one or more specific External Resource(s) that can be verified by the Transmission Provider as Capacity Resource(s) and which does not include any portion(s) of an External Resource that has already qualified as a Capacity Resource; (e) demonstrating that there is firm transmission service for each Season that the resource is to be registered in from the External Resource to the border interface CPNode of the Transmission Provider Region and either that firm Transmission Service has been obtained to deliver capacity on the Transmission System from the border to a Load within an LRZ or demonstrating deliverability as described in Section 69A.3.1.g; and (f) certifying that any External

Resources being identified are not otherwise being used as capacity resources in any other RTO/ISO, in another resource adequacy construct, or in an external balancing authority's resource plan for its firm end-use load and capacity sales requirements within the external balancing authority area.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for an External Resource has not completed GVTC testing by the deadlines provided in 69A.3.1.c.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out (including through bilateral ZRC transactions) subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data for an External Resource of less than 10 MW based upon GVTC is not required if the Market Participant has never provided such data for such External Resource. A Market Participant that begins reporting generator availability data for an External Resource that is less than 10 MW based on GVTC must continue to report such data. All new External Resources or an existing External Resource that has an increased installed capacity shall submit their GVTC to the Transmission Provider prior to qualification as established in the BPM for Resource Adequacy. In accordance with the qualification provisions in the BPM for Resource Adequacy, the Transmission Provider will qualify an External Resource for the applicable Season in the upcoming Planning Year.

4. In the case of a power purchase agreement (PPA), including, but not limited to a Diversity Contract, then the agreement shall meet the additional qualification requirements set forth below:
  - i. A PPA that does not identify the full Installed Capacity of the External Resource from which power will be supplied must specify the portions of each such External Resource that is available under the PPA (i.e. slice-of-system resources) and that are verifiable by the Transmission Provider. Each External Resource specified in such PPA must meet the criteria for a Capacity Resource for all of the portion of the contract amount assigned to the External Resource(s). The capacity from the External Resource will be reduced proportionately to remove amounts that fail to meet such criteria.
  - ii. A copy of every PPA must be provided by the Market Participant using External Resources from such PPA as a Capacity Resource to the Transmission Provider to enable it to verify the External Resource(s) that are backing the PPA and to confirm compliance with RAR. Any redacted versions of a PPA submitted by a Market Participant must contain sufficient information to allow the Transmission Provider to verify compliance with RAR. The Transmission Provider will maintain the confidentiality of these agreements in accordance with the confidentiality provisions in Section 38.9 of the Tariff.
  - iii. For PPAs executed after April 3, 2014, one of the following must apply regarding the external balancing authority in which the External Resource is located:

(a) In the case of unit specific sales, if the MISO Balancing Authority Area is experiencing an Energy Emergency, the external balancing authority will not interrupt the PPA Schedule from the External Resource unless the generator being used to serve the unit specific sale has a forced outage.

(b) In the case of slice-of-system sales, if the external balancing authority area experiences an Energy Emergency and the MISO Balancing Authority Area is simultaneously experiencing an Energy Emergency, the external balancing authority will only interrupt the PPA Schedule on a pro rata basis with the shedding of firm end-use load in the external balancing authority area. Pro rata interruption of the PPA Schedule from the External Resource will be determined as the ratio of the PPA Schedule to the sum of the external balancing authority firm end-use load plus the PPA Schedule. (c) If the external balancing authority (1) is located within the Transmission Provider's reliability coordinator area; (2) participates in a contingency reserve sharing group with the Transmission Provider; and (3) has a Seams Operating Agreement with the Transmission Provider containing the following features, then in the event that the external balancing authority area experiences an Energy Emergency and the MISO Balancing Authority Area is simultaneously experiencing an Energy Emergency, the Transmission Provider and the external balancing authority will share interruption of PPA Schedules from an External Resource and load shedding in the external balancing authority area on a pro rata basis in proportion to the end-use load in the area under the Energy Emergency. Pro rata sharing shall be

determined as the respective ratio of each of the balancing authority's end-use load in the Energy Emergency Area divided by the sum of the end-use load of each balancing authority in the Energy Emergency Area. The Seams Operating Agreement must (1) ensure that the external balancing authority has established a planning reserve margin and qualifications for planning resources using processes and criteria comparable to the Transmission Provider; (2) specify the actions that will be taken by both entities during an Energy Emergency prior to implementing firm end-use load shedding, and (3) specify that the external balancing authority will submit end-use load estimates to the Transmission Provider in a comparable manner as submitted by Load entities in Module E-1, provide generator GVTC and GADS data for all resources used to serve firm requirements of the external balancing authority, and provide transparency in the form of submittal of fixed resource plans comparable to processes used by Market Participants for Fixed Resource Adequacy Plans in the Transmission Provider's Module E-1.

- iv. A PPA executed prior to April 3, 2014 will continue to qualify as a Planning Resource for the full term of the PPA if it is only interruptible as a last resort under Requirement 2 of NERC Standard EOP-011-1. A Diversity Contract executed prior to April 3, 2014 will continue to qualify as a Planning Resource, if it is only interruptible as a last resort under Requirement 2 of the NERC Standard EOP-011-1 between June 1st and September 30th.

- v. A Market Participant may only qualify a PPA as a Capacity Resource if such agreement establishes a firm obligation on the part of the seller of the Capacity to deliver the Capacity to the Market Participant.
- vi. If the terms and conditions in a PPA do not explicitly conform with every requirement of Section 69A.3.1.c. 4 (i) through (iv) above, the Transmission Provider will use alternative documentation and verification procedures to determine if the PPA qualifies as a Capacity Resource. A party seeking Capacity Resource status for a non-conforming PPA must provide the Transmission Provider with written information regarding whether: (a) the PPA was executed prior to October 20, 2008; (b) an RE has accredited the PPA to satisfy resource adequacy requirement provisions; (c) the PPA has provided reliable capacity to the Transmission Provider Region; (d) the supplier(s) of capacity in the PPA commit(s) to provide the capacity to an LSE in the Transmission Provider Region in a defined amount at a defined location based upon the supplier(s)' portfolio of generation assets; (e) energy from the PPA cannot be interrupted for economic reasons and will only be interrupted for force majeure type conditions as a last resort during Emergency conditions; (f) either the purchaser(s) or the supplier(s) of capacity in the PPA has committed to offer energy into the Day-Ahead Energy and Operating Reserves Market and all pre-Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment processes for all periods for which energy is available under the PPA, consistent with the must offer provisions in Section 69A.5; (g) the physical resource(s) backing the PPA are identified by the

supplier of the PPA; (h) the portion of the physical resources backing the PPA has not otherwise been registered by any other entity as Capacity Resources in the Transmission Provider Region or as capacity resources in any other region; and (i) if the PPA is renewed, the PPA will be modified to comply with the terms of section 69A.3.1.c. 4 (i) through (iv) and (vi). The Transmission Provider will analyze all available alternative documentation and verification information.

Based upon such analysis, the Transmission Provider will inform the party seeking Capacity Resource status for the PPA within 30 days whether the PPA qualifies as a Capacity Resource.

- vii. No PPA may be qualified as a Capacity Resource if such agreement includes provisions permitting the seller to interrupt deliveries thereunder for reasons other than Force Majeure.
5. A Market Participant for an External Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the External Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline.

Denial of an extension will not preclude the Market Participant for the External Resource from utilizing the ICAP Deferral process as described in Section 69A.7.9.

6. Existing Resources that modify their registration, scheduling and market participation in the Energy and Operating Reserves Markets and become pseudo-tied External Resources after September 1, 2022 will be accredited at the lesser of class average SAC in Schedule 53 or the accreditation provisions governing External Resources in section 69A.4.1.b.

### **Use Limited Resources**

The Market Participant shall identify eligible Generation Resources, Electric Storage Resources, Distributed Energy Aggregated Resources or External Resources to the Transmission Provider that are Use Limited Resources. The Market Participant that seeks to qualify a Generation Resource, Distributed Energy Aggregated Resource or External Resource as a Use Limited Resource under RAR shall meet all the requirements as specified in the BPM for Resource Adequacy. A Use Limited Resource must be able to operate for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day in each applicable Season in order to qualify as a Capacity Resource, in accordance with the BPM for Resource Adequacy.

## **Intermittent Generation, Dispatchable Intermittent Resources, and Distributed Energy**

### **Aggregated Resources**

Intermittent Generation, Dispatchable Intermittent Resources, and Distributed Energy

Aggregated Resources are resources that are eligible to qualify as a Capacity Resource by a Market Participant provided that the Market Participant: (a) possesses ownership or equivalent contractual rights for the resource; (b) supplies historical performance data or required documentation for the resource as established in the BPM for Resource Adequacy; and (c) registers the resource with the Transmission Provider in accordance with the BPM for Market Registration (if the resource is located within the MISO Balancing Authority Area metered boundary), or the BPM for Resource Adequacy (if the resource is located outside the MISO Balancing Authority Area metered boundary).

### **Curtailments**

At its sole discretion, the Transmission Provider may curtail exports not being used as capacity by an external balancing authority and/or recall External Resources, PPAs, and Diversity Contracts sourced from a Capacity Resource during a declared Energy Emergency. Procedures for such actions shall be specified in the operating procedures. With respect to external balancing authorities that have a Seams Operating Agreement with the Transmission Provider pursuant to Section 69 A.3.1.c.4, during a declared Energy Emergency in the MISO Balancing Authority Area, the Transmission Provider shall only interrupt or reduce Export Schedules associated with a sale of capacity on a reciprocal pro rata basis to that required of the external balancing authority in Section 69A.3.1.c.4.(iii).

**A. Determination of Deliverability of Generation Resources, Electric Storage**

**Resources, and External Resources:**

The Transmission Provider shall be responsible for determining whether Generation Resources, Electric Storage Resources, and External Resources eligible to be Capacity Resources are deliverable to Load. The deliverable amount of such Generation Resources, Electric Storage Resources, and External Resources will be any combination of the following:

- i. The amount of Network Resource Interconnection Service under Attachment X;
- ii. The amount of Energy Resource Interconnection Service under Attachment X that is coupled with firm Transmission Service;
- iii. The amount of firm Transmission Service associated with a Grandfathered Agreement that can only be used to satisfy PRMR within the LRZ of the Load under the Grandfathered Agreement;
- iv. The amount of aggregate deliverability that a Generation Resource or External Resource was granted through the market transition deliverability test by the Transmission Provider and could qualify for Network Resource Interconnection Service; or
- v. The amount of non-aggregate deliverability that a Generation Resource or External Resource was granted by the transmission provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that corresponding Transmission Owner's integration date, will be accepted by the Transmission Provider as deliverable to the Network Loads of

the Network Customer for that term of the confirmed designation, as such term may be extended.

**B. Determination of Deliverability of Intermittent Generation, Dispatchable**

**Intermittent Resources, and Electric Storage Resources:**

The Transmission Provider shall be responsible for determining whether Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources eligible to be Capacity Resources are deliverable to Load. The deliverable amount of such Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources will be any combination of the following:

- i. The amount of Network Resource Interconnection Service under Attachment X;
- ii. The amount of Energy Resource Interconnection Service under Attachment X that is coupled with firm Transmission Service;
- iii. The amount of firm Transmission Service associated with a Grandfathered Agreement that can only be used to satisfy PRMR within the LRZ of the Load under the Grandfathered Agreement;
- iv. The amount of aggregate deliverability that the Intermittent Generation or Dispatchable Intermittent Resource was granted through the market transition deliverability test by the Transmission Provider and could qualify for Network Resource Interconnection Service; or,
- v. The amount of non-aggregate deliverability that a Intermittent Generation or Dispatchable Intermittent Resource was granted by the transmission provider and confirmed by a Network Customer as a designated Network Resource under the

OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that corresponding Transmission Owner's integration date, will be accepted by the Transmission Provider as deliverable to the Network Loads of the Network Customer for that term of the confirmed designation, as such term may be extended.

**C. Determination of Deliverability of Distributed Energy Aggregated Resources**

The Transmission Provider shall be responsible for determining whether Distributed Energy Aggregated Resources eligible to be Capacity Resources are deliverable to Load. The Distributed Energy Resource Aggregator will coordinate with the Electric Distribution Company in order for the Electric Distribution Company to perform a technical review of the Distributed Energy Aggregated Resource's transmission system impacts. Any MW found to be injecting onto the transmission system as a result of the technical review must demonstrate deliverability by obtaining External Network Resource Interconnection Service or firm Transmission Service in order to qualify for the Planning Resource Auction or a FRAP.

## **Retirement, Suspension, Installed Capacity (ICAP) Deferral and Replacement of Planning**

### **Resources**

#### **a. Retirement, Suspension, ICAP Deferral and Replacement**

A Planning Resource for which a Market Participant requests a change in status in accordance with the System Support Resource (SSR) provisions described in Section 38.2.7 will no longer qualify as a Planning Resource effective as of the actual date that the status of the Planning Resource changes to Retire pursuant to Section 38.2.7. A Generation Resource that has the status of Suspend pursuant to Section 38.2.7 will continue to qualify as a Planning Resource in accordance with the BPM for Resource Adequacy. A Planning Resource for which a Market Participant submits an ICAP Deferral Notice will be subject to ICAP Deferral Requirements and Charges pursuant to Section 69A.7.9. As used in this section, “cleared ZRCs” include ZRCs that cleared in the PRA, were used in a FRAP, were used in an RBDC Opt Out, or were used to replace ZRCs in accordance with this section. As used in this section, “uncleared ZRCs” include ZRCs that did not clear in the PRA, were not used in a FRAP, were not used in an RBDC Opt Out or were not used to replace ZRCs in accordance with this section. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is Retired or Suspended prior to the end of the Season during the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs. If a Market Participant does not replace such ZRCs associated with a Retired or Suspended Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section. If a Market Participant’s Planning Resource fails to satisfy the ICAP deferral requirements set forth in Section 69A.7.9 and the Market Participant does not replace

cleared ZRCs with uncleared ZRCs, an ICAP Deferral Non-Compliance Charge will be assessed pursuant to Section 69A.7.9. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Section 69A.5 for greater than thirty-one (31) Days in total due to full or partial Generator Planned Outage during the Season of the Planning Year in which the ZRCs cleared, or for Planning Resources that are subject to Diversity Contracts for greater than one (1) Month during any Season of the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. If a Market Participant does not replace such ZRCs associated with a Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section. A Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs that are used to replace cleared ZRCs must meet the applicable performance requirements as described in sections 69A.3.3.1 and 69A.5 for the balance of the Season of the Planning Year, subject to the same replacement requirements set forth above. Any combination of cleared or replaced ZRCs that are on full or partial Generator Planned Outage for greater than thirty-one (31) Days in total during a Season, or for any other reason including full or partial Generation Outages that were not planned but were known or could have been reasonably anticipated at the time of the PRA, as set forth in the Market Monitoring and Mitigation Business Practices Manual, or unavailable because subject to a Diversity Contract that is not available for greater than one (1) Month during a Season, will be assessed a Capacity Replacement Non-Compliance Charge. If a Planning Resource for which a Market Participant converts Seasonal Accredited

Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Sections 69A.3.3.1 and 69A.5 due to a Catastrophic Generator Outage any time during the Season(s) of the Planning Year in which the ZRCs cleared such Market Participant may replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. A Planning Resource may not transfer its performance requirements by replacing the cleared ZRCs with uncleared ZRCs other than in the case of suspension, retirement, ICAP deferral, Catastrophic Generator Outage or full or partial Generator Planned Outages that may exceed thirty-one (31) Days in the Season as discussed immediately above. Cleared ZRCs can be replaced with uncleared ZRCs that are not from the same LRZ or ERZ by examining post-replacement clearing as if it were the PRA clearing results, so that such replacement: (1) does not violate any CIL used in the PRA; (2) does not violate any CEL used in the PRA; (3) does not reduce the remaining total ZRCs for any LRZ of cleared ZRCs below the LCR for that LRZ; and (4) does not exceed any intra-regional flow ranges established under applicable seams agreements, coordination agreements, or transmission service agreements. ZRC replacements from LRZs or ERZs other than that of the cleared ZRCs will be processed in accordance with the following parameters:

- i. ZRC replacement shall be processed on a first come, first served basis.
- ii. The amount of cleared ZRCs in each LRZ or ERZs at the time of a ZRC replacement shall be based upon the current amounts of cleared ZRCs, including any previous replacement transactions.

ZRC replacement shall have no impact on settlements from the PRA, FRAPs, and RBDC Opt Out, including any assessed Capacity Replacement Non-Compliance Charges.

**b. Capacity Replacement Non-Compliance Charge and Distribution**

- i. Capacity Replacement Non-Compliance Charges will be calculated as follows:  
the number of days for which the Market Participant had a replacement requirement but failed to replace per section 69A.3.1.h.a above multiplied by the amount of ZRCs that failed to be replaced multiplied by the sum of the ACP for the applicable Season and the daily CONE value (1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource cleared those ZRCs. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in the respective SRRZ. For External Resources represented in ERZs that are connected to multiple SRRZs or that are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.
- ii. Distribution of Capacity Replacement Non-Compliance Charges: Capacity Replacement Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs that have met their Final PRMR during the applicable Season of the Planning Year on a *pro rata* basis, based upon their respective LSEs' share of Final PRMR for the Transmission Provider Region.

### **Energy Efficiency Resources (EE Resource)**

An Energy Efficiency Resource is a Planning Resource, in which the Market Participant possesses ownership or equivalent contractual rights, from an end-use customer project (including the installation of more efficient devices or equipment or implementation of more efficient processes or systems) that was implemented after July 20, 2011, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous reduction in electric energy consumption during On Peak daylight hours, as further described in the BPM for Resource Adequacy. EE Resources are eligible to qualify as Planning Resources by registering such EE Resources as Planning Resources with the Transmission Provider, as documented in the BPM for Resource Adequacy. An EE Resource can qualify as a Planning Resource for ZRCs for each Season for up to four (4) Planning Years immediately following the EE Resource's initial qualification provided that the energy efficiency measures are fully implemented prior to each Planning Year. ZRCs from EE Resources will be grossed-up by the amount of avoided transmission losses in accordance with Section 68A.8.b and also by the applicable PRM in accordance with Section 68A.2. EE Resources shall not require notice, dispatch, or operator intervention, such that the EE Resource will reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service, in accordance with the BPM for Resource Adequacy. The additional requirements for EE Resource measurement and verification are found in Attachment UU.

### **Demand Response Resources – Type I and Load Modifying Resources**

Demand Response Resources – Type I and Load Modifying Resources can be offered as ZRCs in the PRA or can be used in FRAPs pursuant to Section 69A.9 or used in an RBDC Opt Out pursuant to Section 69A.9.1. As described below, a Demand Resource or behind the meter generation is eligible to qualify as a DRR – Type I or a Load Modifying Resource if it meets the following requirements. All DRR – Type I and LMRs that are cleared in the PRA or were submitted in a FRAP for a Season or submitted in an RBDC Opt Out must be available for use in the event of an Emergency as declared by the Transmission Provider, pursuant to the Emergency Operating Procedures of the Transmission Provider, unless replaced with other ZRCs pursuant to Section 69A.3.1.h. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DRR – Type I or LMR for the applicable Season in the upcoming Planning Year. The Seasonal Accredited Capacity for DRR – Type Is and LMRs will be calculated pursuant to Schedule 53B.

### **Deployment Procedures for LMR**

Procedures for deployment of LMR are found in the BPM for Resource Adequacy and emergency operating procedures. Such procedures shall be consistent with the information provided by the Market Participant regarding availability and notice time. At a minimum the Market Participant will provide the deployment parameters of the LMR (as described in Sections 69A.3.5 and 69A.3.6), during declared Emergencies prior to the use of Operating Reserves to achieve energy balance. The Market Participant shall, at all times, notify the Transmission Provider or Local Balancing Authority when the status or availability of an LMR changes, except for de minimis changes that do not need to be reported, according to procedures specified in the BPM for Resource Adequacy and emergency operating procedures. The Transmission Provider or Local Balancing Authority shall coordinate with the Market Participant that owns or controls such LMR when necessary to deploy or notify such LMR of a planned deployment. The Transmission Provider or Local Balancing Authority shall coordinate with the Market Participant that owns or controls such LMR when necessary to notify such LMR of a planned deployment through the issuance of Scheduling Instructions. Market Participants may be issued Scheduling Instructions during a declared Emergency or in anticipation of an Emergency at the discretion of Transmission Provider. Market Participants shall acknowledge Scheduling Instructions issued in accordance with BPM for Resource Adequacy for its LMRs. In the event of an anticipated Emergency where the Transmission Provider does not declare the actual Emergency at least two hours prior to the anticipated Emergency event, Market Participants are not obligated to meet the Scheduling Instructions issued in anticipation of such Emergency and

will not be penalized for non-performance. This does not apply to Scheduling Instructions issued after the declaration of an Emergency.

A Market Participant that acknowledges Scheduling Instructions for its LMR(s) as required by the BPM for Resource Adequacy will receive credit for one (1) of the minimum deployments or interruptions required for the LMR for the applicable Season whether or not an Emergency is declared. However, a Market Participant that fails to acknowledge the Scheduling Instructions as required by the BPM for Resource Adequacy will not receive credit for such deployment or interruption for its LMR(s).

An LMR that does not perform consistent with the Market Participant's response to its Scheduling Instructions in the event of an Emergency is subject to the penalty provisions of Section 69A.3.9 and will not receive credit as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season.

### **Demand Resources (DR) with an Emergency Obligation**

Demand Resources registered as either a DRR – Type I or LMR may be deployed to reduce Demand consistent with the submitted Capacity Availability submitted by the Market Participant representing the Demand Resource. A Market Participant shall test, validate, and measure its Demand Resources and submit the results to the Transmission Provider, which shall verify all Demand reduction claimed by a Market Participant, consistent with the procedures specified in the BPM for Demand Response. The accrediting, testing, validation, and Measurement and Verification developed by the Transmission Provider shall take into account any applicable State Regulatory Authority, Regional Entity, or other non-jurisdictional entities' requirements regarding duration, frequency and notification processes for the candidate Demand Resource. A Demand Resource that is sensitive to temperature changes or that is using a Statistical Measurement and Verification methodology must identify, at the time of registration, the extent of such parametric sensitivity to the Transmission Provider with sufficient detail to enable the Transmission Provider to verify whether the Demand Resource would be subject to penalties in Section 69A.3.9 for failure to achieve the targeted Demand reduction amount using the appropriate consumption baseline set forth in Attachment TT. Parametric sensitive analysis must include, but is not limited to, identifying the parameter changes and the parameter's elasticity of the LSE's Load, as further described in the BPM for Demand Response. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DR for each Season in the upcoming Planning Year.

### **Demand Resource Eligibility**

A Market Participant that possesses ownership or equivalent contractual rights in a Demand Resource can register a Demand Resource as a DRR – Type I or an LMR to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. The Market Participant registering the Demand Resource must include the contracts with each end-use customer indicating rights to require the Demand Resource to curtail Load. Notwithstanding, a copy of a contract with an end-use customer will not be required if the Market Participant is the end-use customer. In addition, the Market Participant must meet the following requirements:

- a. A Market Participant shall be prohibited from registering into the PRA any component of a Demand Resource that is concurrently registered, in whole or in part, under another DRR, LMR, or EDR whether by the same or a different Market Participant. A Demand Resource registering as an LMR shall not also register as either a DRR or EDR.
- b. The Demand Resource must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a Load Modifying Resource that is capable of reducing an LSE's Demand for the applicable Season may qualify in meeting this standard).
- c. The Demand Resource must be available to be scheduled for a Demand reduction with a notification time requirement: (i) less than or equal to six (6) hours to register in the PRA as a DRR – Type I or an LMR – Type I; or, (ii) less than or equal to thirty (30) minutes to register as an LMR – Type II, in the applicable Seasons.

- d. When a Demand Resource is issued Setpoint Instructions or Scheduling Instructions, performance will be evaluated as set forth in Attachment TT using the applicable Measurement and Verification.
- e. Once the Setpoint Instruction, Scheduling Instruction, or Firm Service Level is achieved, the Demand Resource must be able to maintain the Setpoint Instruction, Scheduling Instruction, or Firm Service Level for at least four (4) continuous Hours.
- f. Unless the Demand Resource is unavailable due to Force Majeure:
  - (i) A Demand Resource participating as a DRR – Type I or an LMR – Type I that is unavailable to respond to all Setpoint Instructions or Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9; and
  - (ii) A Demand Resource participating as an LMR – Type II that is unavailable to respond to any Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9.

This obligation only applies to Seasons during which a Demand Resource clears the Planning Resource Auction.

- g. A Demand Resource for which curtailment is not an obligation during Emergency events declared by the Transmission Provider pursuant to the Transmission Provider emergency operating procedures, will not qualify to participate in the PRA as a DRR – Type I or qualify as an LMR.  
  
A Market Participant that submits an Offer into the Day-Ahead and/or Real-Time

Energy and Operating Reserve Markets for a Demand Resource is still subject to the requirements to be available during an Emergency pursuant to the Transmission Provider Emergency Operating Procedures, regardless of the projected or actual Real-Time Energy market LMP.

- h. A Demand Resource shall submit Metered data at regular intervals as set forth in Attachment TT.
- i. A Market Participant must demonstrate demand reduction capability for each Planning Year on an annual basis as established in the BPM for Resource Adequacy. Beginning with the 2020/2021 Planning Year each Demand Resource must validate its performance by meeting the Transmission Provider's Scheduling Instructions when called upon during the prior Planning Year or conducting a real power test. A Demand Resource for which a real power test is conducted will receive credit as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season of the Planning Year in which such a test occurs.

A Demand Resource may provide operational data, or develop an alternative mechanism, subject to the approval of the Transmission Provider, by which the demand reduction capability can be demonstrated without requiring an actual demand reduction if a real power test is precluded or waived due to one of the two conditions as specified below:

- 1) Such a real power test is precluded by any applicable regulatory restriction and such a limitation is documented during DR registration; or

2) A Market Participant may waive the obligation to conduct a real power test by notifying the Transmission Provider during DR registration and accepting a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode described in and distributed pursuant to Section 69A.3.9. A Demand Resource providing such notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the ICAP value registered, but not tested, multiplied by \$2,400/MW, where \$2,400 is the product of  $3 * 4 * \$200$  to account for the three (3) times energy penalty assumed under the waiver, the four (4) hours of LMR requirements, and a \$200 LMP as a proxy for pricing under emergency conditions.

All existing accredited Demand Resources that neither conduct a real power test nor meet Scheduling Instructions issued by the Transmission Provider during the prior Planning Year must participate in training provided by the Transmission Provider on the deployment of LMRs during the prior Planning Year. Any existing accredited Demand Resource must submit (1) the real power test results, (2) reference performance of Scheduling Instructions for demand reduction when called upon during the calendar year prior to the upcoming Planning Year, (3) alternate testing mechanism, relevant data, and a reference of training participation to the Transmission Provider, or (4) a Demand Resource Deferral Notice pursuant to 69A.3.5(1) and a reference of training participation to the Transmission Provider no later than February 1 prior to such Planning Year for

existing accredited DR. For new Demand Resources, (1) a real power test must be conducted and results submitted to the Transmission Provider, (2) alternate testing mechanism must be submitted, or (3) a Demand Resource Deferral Notice must be submitted prior to qualifying as a Demand Resource, but no later than March 1 prior to the PRA in accordance with the BPM for Resource Adequacy. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 for existing accredited Demand Resource, and Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 prior to initially qualifying as a Demand Resource.

- j. Market Participants providing physical, regulatory, or contractual limitations of the notice times and availability of Demand Resources must provide appropriate documentation to the Transmission Provider in accordance with the BPM for Resource Adequacy.
- h. A Market Participant may defer the obligation to conduct a real power test, as set forth in section 69A.3.5(i), by providing a Demand Resource Deferral Notice to the Transmission Provider in writing and signed by an officer of the company no later than February 1<sup>st</sup> prior to the Planning Year. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 for existing accredited Demand Resource, and Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 prior to initially

qualifying as a Demand Resource. The Demand Resource Deferral Notice shall contain: (1) the expected Demand Resource test value (in megawatts) from such Demand Resource and if the Demand Resource is new, the LBA or external BA where it is represented; and (2) appropriate information validating that real power test results will be submitted to the Transmission Provider by the last Business Day of May prior to the Planning Year. A Market Participant that provides a Demand Resource Deferral Notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the amount of Demand Resource test value provided in the Demand Resource Deferral Notice multiplied by \$2,400/MW, where \$2,400 is the product of 3\*4\* \$200 to account for the three (3) times energy penalty assumed under the deferral, the four (4) hours of LMR requirements, and a \$200 LMP as a proxy for pricing under emergency conditions. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants that have elected to submit a Demand Resource Deferral Notice must satisfy credit requirements by March 31, 2021. If the Market Participant submits the real power test results on or before the last Business Day of May prior to the Planning Year that are equal to or greater than the expected Demand Resource test value, then the Transmission Provider will adjust the Market Participant's credit requirement to account for these changes within twenty (20) Business Days after that real power test is submitted. In the event ZRCs associated with a Planning Resource for which Demand Resource testing has been successfully deferred are unconverted in accordance with section

69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred Demand Resource value, in which case the Transmission Provider will adjust the Market Participant's Demand Resource value and credit requirement within twenty (20) Business Days. A Market Participant that provides a Demand Resource Deferral Notice and that either (1) has not submitted any real power test result for such Demand Resource by the last Business Day of May prior to the Planning Year, or (2) has submitted a real power test result by the last Business Day of May prior to the Planning Year that demonstrates fewer megawatts are available than the expected Demand Resource test value submitted in the Demand Resource Deferral Notice, shall be subject to a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode for any such deficiency described in and distributed pursuant to Section 69A.3.9. In addition, such Market Participant shall not have their credit released until a real power test result demonstrating the availability of all megawatts submitted in the Demand Resource Deferral Notice is submitted and verified by the Transmission Provider, or the end of the Planning Year, whichever is earlier.

### **Behind the Meter Generation Eligibility**

1. A Market Participant that possesses ownership or equivalent contractual rights in a behind the meter generator can register such behind the meter generator as a DRR – Type I or an LMR to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. A behind the meter generator registered as a DRR – Type I or an LMR is a BTMG. The Market Participant registering the BTMG must include the contracts with each end-use customer indicating rights behind the BTMG to generate behind-the-meter generation. Notwithstanding, a copy of a contract with an end-use customer will not be required if the Market Participant is, or has non-contractual legal rights to control, the end use customer. In addition, the Market Participant must meet the following requirements:
  - a. A Market Participant shall be prohibited from registering into the PRA any BTMG that is concurrently registered, in whole or in part, under another DRR, LMR, or EDR, whether by the same or a different Market Participant. A BTMG registering as an LMR shall not also register as a DRR or EDR.
  - b. The BTMG must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a Load Modifying Resource that is capable of reducing an LSE's Demand for the applicable Season may qualify in meeting this standard).
  - c. A behind the meter generator for which curtailment is not an obligation during Emergency events declared by the Transmission Provider will not qualify to participate in the PRA as a DRR – Type I or qualify as an LMR.

A Market Participant that submits an Offer in the Day-Ahead Market and/or Real-Time Energy and Operating Reserve Markets for a BTMG is still subject to the requirement to be available during an Emergency pursuant to the Transmission Provider Emergency Operating Procedures, regardless of the projected or actual Real-Time Energy Market LMP.

- d. A Market Participant shall demonstrate GVTC capability for applicable Season in each Planning Year on an annual basis as established in the BPM for Resource Adequacy, and by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing accredited BTMG unless the Transmission Provider has granted an extension pursuant to Section 69A.3.6.1.j. All new BTMGs or an existing accredited BTMG that has an increased installed capacity shall submit their GVTC to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA as established in the BPM for Resource Adequacy.
- e. A Market Participant shall submit generator availability data (including, but not limited to, NERC GADS information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy. A Market Participant is not required to report generator availability data based on GVTC for a BTMG less than 10 MW if the Market Participant has never provided such data for such BTMG. A Market Participant that begins reporting generator availability data based upon GVTC for a BTMG that is less than 10 MW must continue to report such data.

- f. A BTMG must be available to provide Energy with a notification time requirement: (i) of six (6) hours or less notice if registering in the PRA as a DRR – Type I or an LMR – Type I; or (ii) with thirty (30) minutes or less notice if registering as an LMR – Type II in the applicable Seasons.
- g. A Market Participant shall demonstrate that the BTMG is able to sustain energy production at the MW level being registered for at least four (4) continuous Hours;
- h. Unless unavailable due to Force Majeure:
  - (i) A BTMG participating as a DRR – Type I or LMR – Type I that is unavailable to respond to all Setpoint Instructions or Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9; and
  - (ii) A BTMG participating as an LMR – Type II that is unavailable to respond to any Scheduling Instruction shall be subject to the penalties set forth in Section 69A.3.9.

This obligation only applies during Seasons which the BTMG clears the Planning Resource Auction.

- i. A BTMG shall submit Metered data at regular intervals as set forth in Attachment TT.
- j. A Market Participant registering a BTMG may not register as a DRR – Type II or Non-Emergency BTMG for three years (3) Planning Years. After three (3) Planning Years, a Market Participant may commit to participate as a BTMG for

an additional three (3) Planning Years or may elect to participate as a DRR – Type II or Non-Emergency BTMG. A BTMG may opt to participate as a DRR – Type I or LMR at any time by satisfying the requirement of such participation option.

- k. A Market Participant for a BTMG required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the BTMG by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extent the GVTC deadline. Denial of an extension will not preclude the Market Participant for the BTMG from utilizing the ICAP Deferral process as described in Section 69A.7.9.

## 2. Installed Capacity (ICAP) Deferral

If a Market Participant for a BTMG has not completed GVTC testing by the deadlines provided in 69A.3.6.1.d, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used the PRA, in a FRAP (including through bilateral ZRC transactions) or in an RBDC Opt Out, subject to the notification, credit, and non-compliance

provisions of Section 69A.7.9.



### **Transmission Provider Initiated Testing of Demand Resources**

1. A Demand Resource participating as a DRR or a LMR that is registered in the PRA shall be subject to a Transmission Provider initiated test according to the following requirements:
  - a. Test frequency:
    - i. A Demand Resource using an Attachment TT defined Statistical Measurement and Verification methodology shall be tested once per Planning Year;
    - ii. A Demand Resource participating as a DRR or LMR – Type I shall be tested once per three (3) Planning Years;
    - iii. A Demand Resource participating as an LMR – Type II shall be tested once per Planning Year. A Market Participant representing a Demand Resource participating as an LMR – Type II may request a Transmission Provider initiated test opt out as set forth in Section 69A.3.8.2; or
    - iv. Notwithstanding the provisions above, the Transmission Provider may test a resource at any time due to its non-performance.
  - b. A Demand Resource that has successfully deployed in response to a Setpoint Instruction or Scheduling Instruction issued during an Emergency in either the past one (1) or three (3) Planning Years as applicable pursuant to sub-section a. above, shall count as a successful Transmission Provider initiated test. Provided there are no deployment failures for a Demand Resource participating as an LMR during the 2025/2026, 2026/2027, and 2027/2028 Planning Years, full

response to Setpoint Instructions or Scheduling Instructions issued during an Emergency shall count as a successful Transmission Provider initiated test for the first one (1) or three (3) Planning Year cycle, as applicable, beginning with the 2028/2029 Planning Year.

- c. A new Demand Resource participating as a DRR or an LMR shall undergo a Transmission Provider initiated test during the first Planning Year it is registered for the PRA.
  - d. A Market Participant shall receive at least 24 hours notification prior to the initiation of a Transmission Provider initiated test. Additional requirements regarding the Transmission Provider initiated test shall be set forth in the BPM for Resource Adequacy.
2. A Demand Resource participating as an LMR – Type II may opt out of the annual Transmission Provider initiated test requirement if it has responded to all Scheduling Instructions and successfully passed all Transmission Provider initiated tests, within the past three (3) Planning Years.
    - a. If opting out of a test, a Demand Resource opting out of the test shall be subject to increased real-time penalties equal to the product of Pricing VOLL and the amount of specified Demand reduction, measured in MWh, not achieved in response to a Setpoint Instruction or Scheduling Instruction issued during an Emergency, in addition to any other penalty provisions set forth in 69A.3.9.
  3. A Demand Resource will be deemed to have fully satisfied the Transmission Provider initiated test if the resource has met its performance obligations, as set forth in

Attachment TT, within the registered notification time, and maintained the Demand reduction or Firm Service Level as applicable for four (4) continuous hours.

4. A Demand Resource will have partially failed the Transmission Provider initiated test if the Demand Resource fully deploys outside of the registered notification time and within six (6) hours of initiating the test for participating as DRR – Type I or LMR – Type I, within thirty (30) minutes of initiating the test for participating as LMR – Type II, and within the Offered Shut-Down time for participating as a DRR – Type II. A partial failure of a Transmission Provider initiated test will result in:
  - a. The Demand Resource being charged the product of the amount of the Demand shortfall, measured in MW at the Hour equal to the initiation of the Transmission Provider test plus the registered response time, and the Auction Clearing Price, for the lesser of:
    - i. The remainder of the Season; or
    - ii. Such time as the Demand Resource fully deploys in response to a Setpoint Instruction or Scheduling Instruction during a Transmission Provider declared Emergency.
  - b. The Transmission Provider will adjust the resource’s registered response time to reflect its tested response. A Market Participant must provide evidence to the Transmission Provider to register such resource with a response time less than the response time achieved during the Transmission Provider initiated test during subsequent Planning Years.
  - c. The Demand Resource may be tested in subsequent Seasons during the same

Planning Year.

- d. The Demand Resource shall be tested in the subsequent Planning Year.
5. A Transmission Provider initiated test shall be deemed to be fully failed if the Demand Resource failed to achieve its required Demand reduction, as measured per the applicable Attachment TT Measurement and Verification identified during the registration of the resource, within six (6) hours of initiating the test for participating as DRR – Type I or LMR – Type I, within thirty (30) minutes of initiating the test for participating as LMR – Type II, and within the Offered Shut-Down time for participating as a DRR – Type II.
- a. A Demand Resource experiencing a complete test failure will be subject to penalties equal to the product of the cleared ZRCs and the ACP for the entire Season in which the test was performed.
  - b. The Transmission Provider shall perform a test in the subsequent Season the resource has cleared ZRCs.
  - c. A resource failing two (2) tests during a single Planning Year shall be fully disqualified for the remainder of the Planning Year and shall pay 2.748 times the applicable LRZ's CONE multiplied by the amount of cleared ZRCs for each Season.

### **Penalty Provisions for LMRs**

Unless an LMR is unavailable as a result of maintenance requirements, for reasons of Force Majeure, or because the number of required deployments based on the registered number has been reached, the Market Participant representing the entity that had ZRCs from LMRs that cleared in the PRA, were used in a FRAP, or were used in an RBDC Opt Out will be subject to the following penalties in the event the LMR is called upon during an Emergency as declared by the Transmission Provider and the LMR fails to perform in accordance with its Market Participant's response to such Market Participant's Scheduling Instructions. The penalties defined below will only apply to the portion of the Market Participant's response to such Market Participant's Scheduling Instruction that is not followed during the Emergency declaration and will only be assessed by the Transmission Provider after giving the operator of the LMR an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties. There will not be an LMR penalty assessed for any portion of the Scheduling Instruction which had already been accomplished by an LMR for other reasons (*e.g.*, for economic considerations, self-scheduling at or above the credited amount of BTMG or local reliability concerns in accordance with instructions from the Local Balancing Authority) at the time the request for interruption is made by the Transmission Provider. Likewise, for certain Demand Resources that are temperature dependent (*e.g.*, a Demand Resource program involving air conditioning load), the specified Demand reduction may be adjusted in a manner defined in the measurement and verification procedures developed by the Transmission Provider to reflect the circumstances at the time a Demand Resource is called upon to reduce Demand.

- a. The Transmission Provider shall assess the responsible Market Participant the costs that were otherwise incurred to replace the deficient Planning Resource at the time the Market Participant's LMR is called upon by the Transmission Provider and does not respond in full or in part consistent with the Market Participant's response to MISO's Scheduling Instructions. These costs will be the product of the amount of specified Demand reduction not achieved and the Hourly Real-Time Ex Post LMP at the Load CPNode, plus any applicable Revenue Sufficiency Guarantee charges. The Transmission Provider shall allocate any such penalty revenues only to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency that required the use of an LMR. Such revenues shall be distributed on a Load Ratio Share basis. For any situation where either an LMR does not respond to an interruption request, including those circumstances where the LMR is claimed to be unavailable as a result of maintenance requirements or for reasons of Force Majeure, the Transmission Provider shall initiate an investigation with the Market Participant which has registered the Demand Resource or BTMG and was qualified as an LMR into the cause of the LMR not being available when called upon to reduce Demand. If deemed appropriate by the Transmission Provider, the Transmission Provider will disqualify the Demand Resource or BTMG from further use as an LMR for the remainder of the current Planning Year, and will discontinue payment of the applicable ACP for the remainder of the current Planning Year when the LMR was unavailable. If such

LMR was used in a FRAP or cleared in the PRA or used in an RBDC Opt Out, then the Market Participant will be charged the applicable ACP for the remainder of the current Planning Year for the Unforced Capacity of the LMR. The revenues collected will be distributed on a *pro rata* basis in such LRZ based upon an LSE's Final PRMR.

- b. In the event the same LMR is unavailable on a second occasion (with at least a separation period of 24 hours) when called upon to respond to Scheduling Instructions, except for a validated circumstance of maintenance requirements or for reasons of Force Majeure, the Market Participant taking credit for that LMR shall make the same penalty payment as indicated in Section 69A.3.9.a above, and the Demand Resource or BTMG will no longer qualify as an LMR and will not receive the applicable ACP for the remainder of the current Planning Year and will not be eligible for LMR status for the next Planning Year. If such LMR was used in a FRAP or cleared in the PRA or used in an RBDC Opt Out, then the Market Participant will be charged the applicable ACP for the remainder of the current planning year for the Unforced Capacity of the LMR. The revenues collected will be distributed on a *pro rata* basis in such LRZ based upon an LSE's Final PRMR.

### **Non-Emergency Behind the Meter Generation Eligibility**

1. A Market Participant that possesses ownership or equivalent contractual rights in a behind the meter generator can register such behind the meter generator as a Non-Emergency BTMG to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. The Market Participant registering the Non-Emergency BTMG must include the contracts with each behind the meter generator indicating rights behind the Non-Emergency BTMG to generate behind-the-meter generation. Notwithstanding, a copy of a contract with a behind the meter generator will not be required if the Market Participant is, or has non-contractual legal rights to control, the behind the meter generator. In addition, the Market Participant must meet the following requirements:
  - a. A Market Participant shall be prohibited from registering into the PRA any Non-Emergency BTMG that is concurrently registered, in whole or in part, whether by the same or a different Market Participant.
  - b. The Non-Emergency BTMG must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a single Non-Emergency Behind the Meter Generation resource may qualify in meeting this standard).
  - c. At registration, a Market Participant registering a Non-Emergency BTMG must commit to participate as a Non-Emergency BTMG for three (3) Planning Years. After three (3) Planning Years, a Market Participant may commit to participate as a Non-Emergency BTMG for an additional three (3) Planning Years or may elect to participate as a DRR – Type I or an LMR. A resource participating as a Non-

Emergency BTMG may opt to participate as a DRR – Type II Resource at any time by satisfying the requirements of a DRR – Type II.

- d. A Non-Emergency BTMG has no obligation to respond to a Transmission Provider Setpoint Instruction or Scheduling Instruction.
- e. A Market Participant registering a Non-Emergency BTMG shall demonstrate GVTC capability for the applicable Season in each Planning Year on an annual basis as established in the Business Practices Manual for Resource Adequacy. A Market Participant of an existing Non-Emergency BTMG must submit the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Non-Emergency BTMG by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Non-Emergency BTMG from utilizing the ICAP Deferral process as described in Section 69A.7.9.

A Market Participant of all new Non-Emergency BTMGs, or an existing accredited Non-Emergency BTMG that have increased installed capacity, shall

submit their GVTC to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA.

A Market Participant may request an extension of these deadlines pursuant to Section 69A.3.10.2.

- f. A Market Participant shall submit generator availability data (including, but not limited to, NERC GADS information) into a database provided by the Transmission Provider and as established in the Business Practices Manual for Resource Adequacy. A Market Participant is not required to report generator availability data based on GVTC for a Non-Emergency BTMG less than 10 MW if the Market Participant has never provided such data for such Non-Emergency BTMG. A Market Participant that begins reporting generator availability data based upon GVTC for a Non-Emergency BTMG that is less than 10 MW must continue to report such data.
- g. A Market Participant for Non-Emergency BMTG shall submit Meter data at regular intervals as set forth in Attachment TT.

## 2. Installed Capacity (ICAP) Deferral

If a Market Participant for a Non-Emergency BTMG has not completed GVTC testing by the deadlines provided in 69A.3.10(e), is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out, subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

### **Planning Resource Capacity Values**

In order for the Transmission Provider to account for resource performance and availability, Capacity Resources, Demand Response Resources – Type I, Load Modifying Resources, and Non-Emergency Behind the Meter Generation will be given a capacity value for each applicable Season based on the Seasonal Accredited Capacity calculation applicable to its Resource type; and EE Resources will be given capacity values based on the measurement and verification data provided for such resources, as provided in the BPM for Resource Adequacy.

### **Seasonal Accredited Capacity of Capacity Resources**

The Transmission Provider will determine the Seasonal Accredited Capacity for each Capacity Resource.

- a. The Seasonal Accredited Capacity for a Capacity Resource that is a Generation Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation, Electric Storage Resource, External Resource, or Use Limited Resource, is based on an evaluation of the type and volume of interconnection service, GVTC value, and Real-Time offered availability of such Generation Resource or Electric Storage Resource for each Season as set forth in Schedule 53.
- b. The Seasonal Accredited Capacity for a Capacity Resource that is an External Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation or Use Limited Resource, is based on the GVTC value and XEFOR<sub>d</sub> values of such External Resource for each Season. External Resources that are not required to report generator availability data will have a forced outage rate based on the class average forced outage rate of the resource type.
- c. The Transmission Provider will determine the Seasonal Accredited Capacity for a DRR – Type II that qualifies as a Capacity Resource, for each Season, as set forth in Schedule 53B.
- d. The Seasonal Accredited Capacity for a Capacity Resource that is a Dispatchable Intermittent Resource or Intermittent Generation will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM

for Resource Adequacy.

- e. The Seasonal Accredited Capacity value for a Capacity Resource that is a Hybrid Resource will be established by the Transmission Provider based on the sum of the Seasonal Accredited Capacity values of its respective Electric Facilities for the production and/or storage for later injection of electricity, up to the level of firm interconnection service, prior to a minimum amount of operating data becoming available. Once sufficient operation data is available, as defined in the BPM, the Seasonal Accredited Capacity value for a Hybrid Resource will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM.
- f. The Seasonal Accredited Capacity of a Capacity Resource that is an Electric Storage Resource will be established by the Transmission Provider based on an evaluation of the type and volume of interconnection service, a GVTC value based upon a power and energy test, and an XEFOR<sub>d</sub>. Electric Storage Resources that are not required to report generator availability data will have an XEFOR<sub>d</sub> rate based on their class average forced outage rate.
- g. The Seasonal Accredited Capacity for a Capacity Resource that is a Use Limited Resource will be determined by the Transmission Provider based on the type and volume of interconnection service, the GVTC and XEFOR<sub>d</sub> values of such Use Limited Resource in accordance with the BPM for Resource Adequacy.

### **Seasonal Accredited Capacity of Demand Resources**

The Transmission Provider will determine the appropriate Seasonal Accredited Capacity value for Demand Resources that qualify as a Planning Resource as established in Schedule 53B.

**Seasonal Accredited Capacity of Behind the Meter Generation and Non-Emergency Behind the Meter Generation**

The Transmission Provider will determine the Seasonal Accredited Capacity for each BTMG and Non-Emergency BTMG as set forth in Schedule 53B. If such BTMG or Non-Emergency BTMG is interconnected to the Transmission System, the Transmission Provider will consider the type and volume of interconnection service when determining the Seasonal Accredited Capacity.

### **EE Resources**

The Seasonal Accredited Capacity for a qualified EE Resource will be determined by the Transmission Provider based upon submitted measurement and verification documents, as provided in the BPM for Resource Adequacy.

### **Attributes of ZRCs**

A Market Participant that owns or possesses equivalent contractual rights to a qualified Planning Resource can convert the convertible Seasonal Accredited Capacity of the Resource (Seasonal Accredited Capacity MW) as determined in section 69.A.3.1.g into ZRCs through the MECT in order to offer such ZRCs into a PRA. Market Participants also can unconvert and/or transfer ZRCs through the MECT to another Market Participant, as described in the BPM for Resource Adequacy.

#### **A. Eligibility for Zonal Resource Credits for a Capacity Resource that is a Planning Resource that is not Intermittent Generation or Dispatchable Intermittent Resource.**

For a Capacity Resource that is not Intermittent Generation or Dispatchable Intermittent Resource the amount of Capacity that is eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal Accredited Capacity value of the Capacity Resource. The convertible Seasonal Accredited Capacity shall be determined by:

- i. Determining the Installed Capacity;
- ii. Determining the Seasonal Accredited Capacity of the Capacity Resource;
- iii. Allocating the Capacity Resource's Seasonal Accredited Capacity value where:
  - a. If the Capacity Resource has only Energy Resource Interconnection Service, the Seasonal Accredited Capacity will be allocated to the Capacity Resource's Energy Resource Interconnection Service Seasonal Accredited Capacity value, which will be calculated by multiplying the lesser of the Capacity Resource's ICAP or Energy Resource Interconnection Service by SAC divided by ICAP;

- b. If the Capacity Resource has both Network Resource Interconnection Service and Energy Resource Interconnection Service, the Seasonal Accredited Capacity will be allocated first to the Capacity Resource's Network Resource Interconnection Service Seasonal Accredited Capacity value, which will be calculated by multiplying the lesser of the Capacity Resource's ICAP or Network Resource Interconnection Service by SAC divided by ICAP, as provided below:

$$NRIS\ SAC = MIN(NRIS, ICAP) \times (SAC/ICAP)$$

- c. Any remaining total Seasonal Accredited Capacity value will then be allocated to Energy Resource Interconnection Service Seasonal Accredited Capacity as provided below:

$$ERIS\ SAC = MAX(0, (ICAP-NRIS)) \times (SAC/ICAP)$$

- d. The resulting Network Resource Interconnection Service Seasonal Accredited Capacity value shall be eligible to be converted into Zonal Resource Credits; and
- e. The resulting Energy Resource Interconnection Service Seasonal Accredited Capacity value that is coupled with firm Transmission Service shall be eligible to be converted into Zonal Resource Credits up to the Energy Resource Interconnection Service Unforced Capacity value of the Capacity Resource, by multiplying the firm Transmission Service amount by SAC divided by ICAP.

**B. Eligibility for Zonal Resource Credits for a Capacity Resource that is an Intermittent Generation or Dispatchable Intermittent Resource**

For Intermittent Generation and Dispatchable Intermittent Resources that are Capacity Resources, the amount of Capacity eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal Accredited Capacity value of the Intermittent Generation or Dispatchable Intermittent Resource, which is equal to the total Seasonal Accredited Capacity value multiplied by the quotient of the deliverability adjusted Capacity factor divided by the peak performance Capacity factor of the Capacity Resource where:

- a. the deliverability-adjusted capacity factor is the average of the actual Energy output capped at the demonstrated deliverability of the Intermittent Generation or Dispatchable Intermittent Resource determined in Section 69A.3.1.g during the highest system peak load observances for each Season that the Capacity Resource was in service divided by the Installed Capacity of the Capacity Resource; and,
- b. the existing peak performance Capacity factor is the average of the actual Energy output during the highest system peak load observances for each Season that the Capacity Resource was in service divided by the Installed Capacity of the Capacity Resource.

**C. Eligibility for Zonal Resource Credits for a Capacity Resource that is a Distributed Energy Aggregated Resource**

For Distributed Energy Aggregated Resources that are Capacity Resources, the amount of Capacity eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal

Accredited Capacity value of the Distributed Energy Resources within the aggregation according to their resource type as determined in section 69A.3.1.g.

### **Capacity Resource Must Offer and Performance Requirements**

- a. Market Participants that convert Seasonal Accredited Capacity from Capacity Resources into ZRCs that clear in a Season in the PRA or are used in a FRAP (and that do not replace such ZRCs in accordance with Section 69A.3.1.h) or used in an RBDC Opt Out, including Capacity Resources that are the subject of Diversity Contracts, must submit Self-Schedules or Offers for Energy, and Contingency Reserve if qualified, and offers for Short-Term Reserve if qualified, for the Installed Capacity value of the Capacity Resources converted to ZRCs and clear in a Season in the PRA or used in a FRAP or used in an RBDC Opt Out for each Hour of each Day during the applicable Season in the Planning Year, in the Day-Ahead Energy Market and all pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment process. This must offer obligation does not apply to the extent that the Capacity Resource is unavailable due to a full or partial forced or scheduled outage, in accordance with the BPM for Resource Adequacy and the BPM for Outage Operations. Additionally, this must offer obligation is modified to the extent the Capacity Resource is provided an operating limitation, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, by the Transmission Provider or Transmission Operator to preserve the reliability of the Transmission System, that is lower than the must offer obligation described above, for the duration of such limitation.

Any such Capacity Resource with full or partial Generator Planned Outages that exceeds thirty-one (31) Days during any Season will be deemed not to have met its performance requirement for any Days greater than thirty-one (31) Days and must replace ZRCs in

accordance with Section 69A.3.1.h, provided that Capacity Resources subject to Diversity Contracts that are unavailable for greater than thirty-one (31) Days in total during any Season, will be deemed not to have met its performance requirement and will be subject to the ZRC replacement provisions set forth in Section 69A.3.1.h.

Self-Schedules or Offers for Energy must be made consistent with requirements specified in Sections 39 and 40 of this Tariff as well as in the BPM for Resource Adequacy and the Business Practices Manual for Energy and Operating Reserves Markets. Partial or full forced or scheduled outages or derates of Capacity Resources must be reported in the Transmission Provider's Outage Scheduler, as described in further detail in the Business Practices Manual for Outage Operations. Must offer requirements specified in the BPM for Resource Adequacy will reflect resource operational limitations, including those related to Use Limited Resources, fuel limited, energy output limited or Intermittent Generation and including all state regulations and laws, including but not limited to, state safety standards, planning reserve margins, or the enforcement thereof. The Transmission Provider will monitor compliance with must offer requirements in accordance with the BPM for Resource Adequacy.

- b. If a Capacity Resource that has ZRCs cleared in the PRA during any Season or is used in a FRAP during any Season or used in an RBDC Opt Out is capable of performing but fails to perform when called upon by the Transmission Provider for an Emergency, the Transmission Provider shall assess the owner of such Capacity Resource the costs that were otherwise incurred to replace the energy from the deficient Capacity Resource at the time that the Capacity Resource is called upon by the Transmission Provider and does not

respond in full or in part, for each day of non-performance of such Capacity Resource, provided that the planned or forced outage of the Capacity Resource is not properly reported in the Transmission Provider's Outage Scheduler, as set forth in the Business Practices Manual for Outage Operations. These costs will be the product of the amount of qualified ZRCs not achieved and the real-time LMP at the Capacity Resource's CPNode, plus any applicable related Revenue Sufficiency Guarantee charges. The Transmission Provider shall allocate any such revenues to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency. Such revenues shall be distributed on a Load Ratio Share basis.

- c. Market Participants must input all Energy Efficiency Resource and Load Modifying Resource information into the MECT at least seven (7) Business Days prior to the Planning Resource Auction.



### **State RAR Standards**

The Transmission Provider will assist states in meeting any state resource adequacy standards by providing relevant MECT information as available and as may be requested by states, subject to the data confidentiality provisions in Section 38.9 of this Tariff. Nothing in the RAR shall prohibit any state from requesting data relating to state safety standards, planning reserve margins, or the enforcement thereof.

### **Information regarding RAR Obligations**

The Transmission Provider will maintain databases and will report to states and the affected LSEs, upon request, aggregated, non-confidential information regarding jurisdictional LSEs' RAR obligations during relevant time periods. Confidential Data regarding RAR status will be provided to states only in accordance with the data confidentiality provisions in Section 38.9 of this Tariff.

### **Facilitation of a Bilateral Capacity Bulletin Board**

The Transmission Provider shall maintain an electronic bulletin board platform that may be used by Market Participants to facilitate voluntary bilateral ZRC transactions and to monitor the conversion of Seasonal Accredited Capacity to ZRCs.

**Facilitation of LSE's RAR Information**

The Transmission Provider shall, upon request, submit RAR information to the applicable RE, Electric Reliability Organization, state (in the case of an LSE subject to regulation or using delivery services rates, terms or conditions established by such State Regulatory Authority) or to the Commission, subject to the provisions of Section 38.9 of this Tariff.

## **Reliability Based Demand Curve Procedures**

### **A. Translation of MRI Curves to RBDCs**

The following process will be utilized to determine the RBDC for the Transmission Provider Region for each Season of the upcoming Planning Year. The MRI Curves for the Transmission Provider Region as described in Section 68A.9 will be multiplied by a scaling factor measured in \$/MWh. The scaling factor for an RBDC is calculated to support ACPs that achieve annual Net CONE when the Transmission Provider Region is at the reliability requirement established by the LOLE analysis for each Season. LOLE risk across the Seasons is modeled as described in Section 68A.2.1. The scaling factors shall be determined as set forth in the Business Practices Manual for Resource Adequacy.

The process used to determine the RBDCs for each of the First Planning Area and the Second Planning Area for each Season in the Planning Year is similar to the process used for developing the RBDC curve for the Transmission Provider Region.

### **B. Monte Carlo Analysis**

Every three Planning Years, the Transmission Provider will evaluate the ability of RBDCs, through probabilistic analysis, to reliably serve the Transmission Provider Region's Demand while supporting ACPs that achieve annual Net CONE when the Transmission Provider Region is at the reliability requirement established by the LOLE analysis for each Season. The probabilistic analysis shall use a Monte Carlo study that assumes there are no internal transmission limitations within the Transmission Provider Region.

The Monte Carlo analysis will model both in-market supply and demand based on historic supply and demand variability, respectively, observed through a minimum of the three

most recent PRAs. The Monte Carlo model will produce seasonal clearing prices and quantities with each draw. Overall model results will be assessed by comparing the average of seasonal prices from the study against the estimate of Net CONE described in section 69A.8. The scaling factor is adjusted in each successive Monte Carlo simulation so that long run equilibrium conditions are ultimately achieved, indicated by the average of seasonal prices from the study equal to the estimate of Net CONE. Net CONE values used for the Monte Carlo analysis will be the simple arithmetic average of all LRZ Net CONE values.

A separate Monte Carlo analysis will be performed to evaluate the RBDCs for the First Planning Area and the Second Planning Area. Separate scaling factors will be used in the Monte Carlo analysis for each of the First Planning Area and the Second Planning Area that supports achievement of Net CONE values for the corresponding Planning Area, indicated by the average of seasonal capacity prices under long run equilibrium conditions. Net CONE values used in the Monte Carlo analysis for the RBDCs for the First Planning Area and the Second Planning Area will be the simple arithmetic average of LRZ Net CONE values for the specific LRZs in the corresponding Planning Area.

### **Planning Resource Auction**

Within twenty (20) Business Days after the last Business Day in March, the Transmission Provider will conduct a PRA to determine the ACP in each LRZ and ERZ for the upcoming Planning Year which begins on June 1st. The Transmission Provider will post the results of the PRA on its website, consistent with the standards and procedures set forth in the BPM for Resource Adequacy. The Transmission Provider shall ensure that each Market Participant submitting a ZRC Offer is qualified to submit such an offer consistent with the Transmission Provider's creditworthiness provisions. The Transmission Provider will ensure that the LCR, the CEL and CIL are respected for each LRZ, the CEL is respected for each ERZ, and the SREC and the SRIC are respected for each SRRZ, if applicable, when conducting the PRA.

## **PRA Procedures**

**a. Participating ZRCs in the PRA:** All Market Participants that own or have contractual rights to the Planning Resources that are represented within an LRZ or ERZ and have converted Seasonal Accredited Capacity to ZRCs, will have an option to (consistent with withholding provisions) submit offers into the PRA for such ZRCs, to the extent that the Market Participant has not submitted a FRAP, or RBDC Opt Out, as described in Section 69A.9. Owners of jointly-owned facilities can individually offer their share of any such resources into the PRA, either as self-schedule price takers or with specific offers, or use their share of such resources as part of their FRAPs, or RBDC Opt Outs. These ZRC Offers must be submitted in price/quantity pairs on a monotonically increasing basis expressed as MW-day and must consist of a stepped ZRC Offer curve of up to five (5) segments for each Planning Resource. ZRC Offers shall be submitted to the Transmission Provider via the MECT during the PRA offer window. Only ZRCs that are not otherwise committed for the remainder of the Planning Year are permitted to participate in the PRA. The PRA offer window shall begin at 8:00 am EPT three (3) Business Days before the last Business Day in March and shall end at 6:00 pm EPT on the last Business Day in March. The Transmission Provider may extend or reopen the PRA offer window based on unanticipated events that: (i) interfere with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) are otherwise likely to have a widespread negative impact on the results of the PRA. The Transmission Provider shall notify Market Participants and post such notice of any extension or reopening of the PRA on its website. The notice shall state the extension or

reopening's circumstances, rationale, and duration. The price associated with these ZRC Offers cannot exceed the annual CONE value divided by the number of days in the Season for the LRZ where the ZRC is represented. ZRC Offers from External Resources represented in ERZs, which are connected to single SRRZ, cannot exceed the greatest CONE value of all LRZs in respective SRRZ. ZRC Offers from External Resources represented in ERZs, which are connected to multiple SRRZs or are not connected to any SRRZs, cannot exceed the greatest CONE value of all LRZs in those connected SRRZs. Owners of ZRCs may bilaterally sell or buy ZRCs; however if a ZRC has cleared in the auction, the Market Participant that registered the Planning Resource that is the subject of such ZRC shall be responsible for complying with all Tariff requirements. The Independent Market Monitor will review the actions of owners/operators of all qualified Seasonal Accredited Capacity from Planning Resources and conversion to ZRCs to evaluate potential withholding of Planning Resources from the PRA, consistent with Module D. External Resources, including Generation Resources pseudo-tied into the MISO Balancing Authority Area, will be granted ZRCs in the applicable External Resource Zone. Notwithstanding the above, External Resources located within a Coordinating Owner that (i) borders the Transmission Provider Region; (ii) whose external ties are predominantly to the Transmission System; and (iii) has Seams Operating Agreements that allow for coordinated operations, will be granted ZRCs in the LRZ where their firm transmission service crosses the border of the Transmission Provider Region, and Border External Resources will be granted ZRCs in the LRZ where the Transmission System connects to the substation with its interconnection facilities.

Generation Resources, Intermittent Generation, Electric Storage Resources, and Dispatchable Intermittent Resources will have to meet the terms of Section 69A.3.1.g. To the extent a Capacity Resource is located on the border of two or more LRZs (e.g., has transmission lines from two or more LRZs terminating at the substation containing the Capacity Resource's interconnection facilities), the Capacity Resource will be assigned to an LRZ as follows:

- (i) if the Capacity Resource is located within the MISO BA, MISO will assign that Capacity Resource to the LRZ that contains the Local Balancing Authority in which the Capacity Resource is physically located; or
- (ii) if the Capacity Resource is a Border External Resource, MISO will assign that Capacity Resource to the LRZ with which it has the greatest electrical connection. This connection will be determined by the impacts of the Resource on the system, including (i) the electrical loading of transmission facilities within and tying to the Zone and (ii) the transmission constraints which define the CIL and CEL for the Zone.

Once assigned, Capacity Resources which border two or more LRZs will not be reassigned unless significant changes occur in the Transmission Provider Region, including but not limited to, significant changes in LRZ boundaries, membership, the Transmission System, and/or Resources.

**b. Participating Demand:** All LSEs will be required to meet their Final PRMR through the PRA process, unless they have decided to pay the Capacity Deficiency Charge. LSEs can Self-Schedule ZRCs to meet their PRMR, consistent with the Self-

Scheduling Option in Section 69A.7.8. The Transmission Provider will conduct the PRA based upon the PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge, expressed as a variable reliability target through RBDCs for all of the LSEs located within the Transmission Provider Region.

**c. Conducting the PRA:** The Transmission Provider will conduct the PRA for each Season using the following auction procedures to determine the ACP for each LRZ and ERZ. The PRA shall be designed to commit resources equal to the Final PRMR determined by application of the RBDC for each LSE, minus the amount of PRMR associated with the Capacity Deficiency Charge but including resources used in a FRAP and an RBDC Opt Out, in each LRZ up to the total volume of offered ZRCs. All ZRCs offered at zero price will clear the PRA. The PRA shall clear for each LRZ and ERZ of the Transmission Provider Region. A multi-zone optimization methodology shall be employed to simultaneously perform the following tasks: (1) conduct the PRA to meet the supply and demand balance both for the Transmission Provider Region and for each of the First Planning Area and the Second Planning Area by clearing ZRC Offers and establishing the Final PRMR, as determined by application of the RBDCs, minus the amount of PRMR associated with the Capacity Deficiency Charge for each LRZ of the Transmission Provider Region to yield cleared ZRCs; (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs and from ERZs; and (4) respect the SREC and SRIC for each SRRZ, if applicable.

(i) **Objective Function:** The objective of the multi-zone optimization methodology shall be to maximize social surplus, using the as-offered overall

costs of capacity procurement and the as-bid overall benefits of capacity procurement reflected in the RBDCs over the time horizon, subject to LCR, network constraints, and SRICs and SRECs, if applicable. The overall costs will include the ZRC Offers of all Planning Resources selected for cleared ZRCs. CILs of each LRZ are simultaneous to the extent that imports into the LRZ are concurrently simulated; and CELs of each LRZ and ERZ are simultaneous to the extent that exports out of the relevant LRZ or ERZ are concurrently simulated. Network constraints will be represented by an initial set of zonal CELs and CILs, driven by the dispatch from planning models. The CELs and CILs will be reviewed by the Transmission Provider to determine if there are network loading violations when based on the geographical dispatch derived from the initial auction clearing. If no network violation is indicated, then the auction results are final. If a network violation is indicated, then reductions will be made to the affected export and import capabilities to avoid network violations and the auction will be cleared again with the new set of export and import capabilities. After a maximum of two (2) successive iterations per Season to address network violations, the auction clearing iteration with the fewest megawatts of network violations will be deemed as the final auction result.

(ii) **Time Horizon:** For purposes of clearing the system-wide PRMR the time horizon is an hour, representing the projected maximum Coincident Peak Demand. For a Local Resource Zone, the time horizon is the hour representing the Local Resource Zone Peak Demand, over each Season for the next Planning

Year for the Transmission Provider Region. Coincident Peak Demand is used to establish an LSE's Initial PRMR while Local Resource Zone Peak Demand is used to establish an LRZ's LRR.

(iii) **Capacity Market and Congestion Management:** The multi-zone optimization methodology will perform congestion management simultaneously with the scheduling of capacity for each Season in the Planning Year. Congestion management is the process where ZRCs are cleared to eliminate network constraint violations and to maximize the social surplus of procuring PRMR to meet applicable reliability standards.

(iv) **Model of Transmission Provider Transmission System:** The multi-zone optimization methodology will enforce network constraints represented by CILs, CELs and LCRs that are obtained by using a model of the transmission system including Planning Resources and Demand which will be updated annually to reflect existing and planned transmission and generation projects. Transmission and Planning Resources shall be modeled as part of the multi-zone optimization methodology to reflect their expected state during the peak Hour of each Season in the Transmission Provider Region. The model is of zonal form, which shall include all Planning Resources, Demand, and a representation of systems external to the Transmission Provider Region, and which will be consistent with seams agreements with neighboring regions.

**Network Constraints.** The multi-zone optimization methodology shall enforce constraints on transmission lines, transformers, and groups of

transmission branches that compose transmission interfaces represented by LCR, CIL, and CEL. Most of these constraints shall represent thermal limits on the power flow through transmission facilities. Certain constraints may impose more restrictive limits on power flow, taking into account contingencies and typically represented through operating guides.

**Transmission Losses.** The multi-zone optimization methodology will clear ZRCs to cover transmission losses; the PRMR will include estimates of transmission losses in its calculation for each Season.

(v) **LRZ ACP Calculation:** The Auction Clearing Price (ACP) for an LRZ is the marginal cost of serving the Demand in that LRZ. The ACP is composed of the system marginal cost of capacity, the regional marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for a LRZ, (*i.e.*, network constraints that are active at the optimal solution prohibiting a lower cost outcome), and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable. The ACP is calculated by considering the next increment or decrement to Demand for each LRZ. The Transmission Provider will calculate ACPs for each LRZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day (\$/MW-day).

(vi) **External Resource Zone (ERZ) ACP:** The ACP for an ERZ is comprised of the system marginal cost of capacity, marginal cost of financially binding CEL for the ERZ, the marginal cost of financially binding SRECs and SRICs for SRRZ with which the ERZ interconnects. For ERZs which connect with more than one

SRRZ, or which do not directly connect to a single SRRZ, a weighted average of the marginal cost of financially binding SREC and SRIC will be applied, with weights derived from the distribution of annual energy flows into the SRRZs from the ERZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day (\$/MW-day).

(vii) **ACP Inputs:** Primary inputs to the ACP calculation are network constraints represented by CIL, CEL, LCR, and other constraints established by the Transmission Provider associated with SRECs and SRICs for SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements and the set of valid ZRC Offers and the Final PRMR for the Transmission Provider Region minus the amount of Initial PRMR associated with the Capacity Deficiency Charge for each LRZ. Valid ZRC Offers may include offers from ZRCs converted from confirmed Seasonal Accredited Capacity from Planning Resources. ZRC Offers can be submitted as Self-Schedules, in accordance with Section 69A.7.8.

(viii) **ACP Outputs:** For non-zero ACPs, Resources that set the ACP in a LRZ or ERZ will be cleared in proportion to the amount of ZRCs necessary to meet the Final PRMR. When more than one resource is marginal and offered at the ACP, then all resources offered at the ACP are cleared *pro rata* up to the amount required to meet the reliability requirement. This may result in a portion of multiple Resources clearing as the marginal resources that set the ACP.

(ix) **Eligibility Rules:** ACPs can be set by any ZRC Offers.

**(x) ACP for multiple Seasons with ZRC Shortage Conditions or ZRC Near-Shortage Conditions to meet Local Clearing Requirements:**

When an LRZ has more than one Season in any combination of ZRC Shortage Conditions and/or ZRC Near-Shortage Conditions the final Auction Clearing Price (ACP) for the LRZ will be set as the minimum of: (a) the original ACP as determined in Section 69A.7.1.c.(v) reflecting the effective financial binding of an LCR constraint; or (b) the summation of: (i) the amount composed of the system marginal cost of capacity, the regional marginal cost of capacity, and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable; and (ii) the LCR price adder. The LCR price adder will be set as the amount obtained by dividing the applicable LRZ's annual CONE value by the summation of the number of days in Seasons in each Season of the Planning Year in which the LRZ was in ZRC Shortage Conditions in the Planning Resource Auction and the number of days in each Seasons of the Planning Year in which the LRZ was in ZRC Near-Shortage Conditions in the Planning Resource Auction.

(xi) **Notification:** ACPs and total summarized cleared ZRC Offers determined as described above shall be calculated and published by the Transmission Provider by 11:59 pm EST on the twentieth Business Day following the last Business Day in March. The Transmission Provider may extend the publishing deadline based on unanticipated events that: (i) interfered with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) were

otherwise likely to have a widespread negative impact on the results of the PRA.

The Transmission Provider shall notify Market Participants and post such notice of any extension of publishing the results of the PRA on its website. The notice shall state the extension's circumstances, rationale, and duration.

### **Consequences of PRA**

All PRA transactions will be financially binding. Market Participants with cleared ZRC Offers must comply with all of the ZRC requirements for all ZRCs that clear in the PRA.

### **Uncleared ZRCs**

Once the PRA has concluded, a Market Participant may convert back to Seasonal Accredited Capacity any ZRCs that do not clear in the PRA.

### **PRA Reporting**

The Transmission Provider will not reveal the ZRC Offers submitted by any Market Participant in a PRA until one (1) month following the completion of the PRA, except as required pursuant to the provisions of Section 38.9 of the Tariff. When the ZRC Offers are posted, price/quantity pairs will be made public, however the names of the Market Participants submitting such offers and the names of the Planning Resources offered shall not be publicly revealed.

### **Market Monitoring**

All actions of Market Participants participating or failing to participate in the PRA shall be subject to the provisions of Module D, except to the extent that a Market Participant has opted out of the PRA as described in Section 69A.9. The Transmission Provider will report any known attempt to exercise market power by LSEs or by Market Participants in the PRA procedures to the Independent Market Monitor.

### **PRA Settlement**

- a. Cleared ZRC Offers will be settled at the ACP for the LRZ or ERZ where the ZRC is represented on a daily basis and the Market Participants submitting cleared ZRC Offers will be credited on a weekly basis by the Transmission Provider. The Transmission Provider will settle the LSEs cost of their Final PRMR minus the amount of PRMR associated with the Capacity Deficiency Charge at the ACP for the LRZ where the Demand is located on a daily basis and will debit LSEs weekly, to the extent that an LSE has not opted out of the PRA pursuant to Section 69A.9 or submitted an RBDC Opt Out pursuant to Section 69A.9.1. For LSEs not selecting RBDC Opt Out, the Final PRMR will be established based on the financial binding of RBDCs representing the Transmission Provider Region and applicable planning area (i.e., the First Planning Area or the Second Planning Area).

Final PRMRs will be determined as follows:

- i. LSEs using the RBDC Opt Out will have Final PRMRs calculated by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by  $(1 + \text{Transmission Provider Region PRM} + \text{RBDC Opt Out Adder})$ .
- ii. LSEs not using the RBDC Opt Out will have Final PRMRs calculated using the formula below:

*Final PRMR for a LSE not using the RBDC Opt Out*

$$\begin{aligned}
 &= \left( \text{PRA Cleared Capacity} \right. \\
 &\quad \left. - \sum \text{Final PRMR for LSEs using the RBDC Opt Out} \right) \\
 &\quad \times \frac{\text{Initial PRMR of the LSE not using the RBDC Opt Out}}{\sum \text{Initial PRMR of all LSEs not using the RBDC Opt Out}}
 \end{aligned}$$

- iii. LSEs under state jurisdiction where the State Regulatory Authority has overridden the PRM established by the Transmission Provider will have Final PRMRs for each Season calculated by multiplying the LSE’s forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + the planning reserve margin established by the State Regulatory Authority).

The Transmission Provider will financially net the ZRC credits and LSE debits for Market Participants. Market Participants with cleared ZRCs sourced from Diversity Contracts will receive reduced credit for any ZRC volumes cleared above their PRMR up to the cleared volume of ZRCs from Diversity Contracts.

The reduced compensation will be based on the total number of days the capacity from the Diversity Contract is dedicated to Demand in the Transmission Provider Region in each Season divided by the total number of days in the Season.

- b. An LSE that submits a FRAP or an RBDC Opt Out with PRMR in an LRZ and ZRCs in an ERZ or a separate LRZ may be subject to a ZDC, as described below:
  - (i) The Zonal Deliverability Charge will be the maximum of: (a) the difference between the ACP for the LSE’s PRMR within an LRZ where an LSE has Demand

that is not met by ZRCs from Planning Resources that are represented in such LRZ and the ACP in the LRZ or ERZ where the LSE's ZRCs are represented; or (b) zero. The Transmission Provider will multiply the ZDC by the ZRCs to obtain the deliverability charge that the Transmission Provider will assess the LSE. The Zonal Deliverability Charge will only be assessed to an LSE's Load that is part of a FRAP or for LSEs submitting ZRCs for an RBDC Opt Out.

- c. Any portion of an LSE's PRMR not covered by the FRAP, minus the amount of PRMR associated with the Capacity Deficiency Charge, shall be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is not recovered by ZRCs in a FRAP.
- d. For instances where a LRZ clears under ZRC Shortage Conditions or ZRC Near-Shortage Conditions to meet Local Clearing Requirement in more than one Season in a Planning Resource Auction and final ACPs are adjusted per Section 69A.7.1.c.(x), certain cleared ZRC Offers may exceed the final ACPs. In this case, such cleared ZRCs may be eligible for a ZRC Offer Revenue Sufficiency Credit, to the extent that settlement amounts credited in paragraph 69A.7.6.a above for a Planning Year are insufficient to cover Allowable ZRC Offer Costs, needed to be incurred by the Planning Resource to be available for cleared Seasons.  
  
ZRC Offer Revenue Sufficiency Credit will be calculated as the greater of: (i) zero; or, (ii) the difference between Allowable ZRC Offer Costs, and the total settlement amounts credited per paragraph 69A.7.6.a for the associated cleared

ZRC Offers for all Seasons in a Planning Year.

Where Allowable ZRC Offer Costs shall equal the minimum of: (i) the sum of all cleared ZRC Offer segment volumes multiplied by the ZRC Offer segment price, multiplied by the number of Days in the Season, calculated for all Seasons for which the ZRCs clear in the Planning Resource Auction; or, (ii) the annual CONE for the LRZ where the ZRCs are represented; or, (iii) the applicable facility-specific Reference Level costs for the Planning Resource, if a Market Participant received a facility-specific Reference Level per Section 64.1.4.

ZRC Offer Revenue Sufficiency Credits will be allocated pro-rata across the Seasons where the ZRC Offer cleared for settlement and distribution.

- e. ZRC Offer Revenue Sufficiency Charges will be assessed as the sum of all ZRC Offer Revenue Sufficiency Credits for a Season distributed to Market Participants representing LSEs in an LRZ clearing under ZRC Shortage Conditions or ZRC Near-Shortage Conditions on a pro rata basis, based upon their respective LSE's share of Final PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge in the appropriate LRZ.

### **Distribution of Excess Auction Revenue**

The following provisions address situations where LSEs will be entitled to receive financial benefits on contractual commitments and/or use of the Transmission System. These benefits will provide LSEs with financial hedges for ACP separation between LRZs and/or ERZs based on excess revenue from the Planning Resource Auction.

The Transmission Provider will distribute any such excess revenues in two stages:

- (i) in the first stage, the Transmission Provider shall distribute such excess revenues to LSEs qualifying for Historic Unit Considerations (HUCs) as described in Section 69A.7.7(a) and ZDC Hedges as described in Section 69A.7.7.(b), then
- (ii) any remaining excess revenue will be distributed in accordance with the Zonal Deliverability Benefit provisions of Section 69A.7.7(c).

The LSE will only receive excess PRA revenue if the ACP paid by the LSE is higher than the ACP received for such Planning Resources. If there are not sufficient excess revenues to fully fund all Historic Unit Considerations and ZDC Hedges, the revenues will be allocated on a pro rata basis to all HUCs and ZDC Hedges.

### **Historic Unit Considerations (HUCs)**

The Transmission Provider will allocate excess PRA revenue to LSEs with ownership or contractual arrangements, limited to a) Grandfathered Agreements, b) arrangements that predate July 20th, 2011, or c) arrangements that predate March 26, 2018 and pertain to External Resource represented in External Resource Zones in which:

- i. The LSE has Initial PRMR obligations equal to or greater than the amount of the Planning Resource designated in the arrangement;
- ii. The Planning Resource designated in the arrangement and Initial PRMR obligation span multiple LRZs and/or ERZs;
- iii. The LSE has long-term (five years or more) contracts for or ownership of the Planning Resource and has maintained continuous firm Transmission Service or firm Network Resource Interconnection Service, and in the case of External Resources, firm transmission service on the applicable external Balancing Authority transmission system, for that Planning Resource to the LRZ containing the LSE's associated Initial PRMR obligation; and
- iv. LSEs must note qualification for HUCs and submit information supporting HUC eligibility to the Transmission Provider by January 15<sup>th</sup> prior to the upcoming Planning Year.

A combination of arrangements that require the delivery of capacity throughout the Planning Year will qualify to receive excess PRA revenue through a HUC, provided that the arrangements satisfy the criteria herein. The volume of MW eligible to receive excess PRA revenue will be the lesser of the cleared ZRCs from the Planning Resource(s) or the amount of Initial PRMR that are

associated with the qualified arrangement. A qualified arrangement shall remain eligible to receive excess PRA revenue for the current term of the executed contract, excluding any evergreen contract extension, or for two Planning Years, whichever is longer. In the event that the owned resource status is changed to retired, the transmission service is not maintained, or the arrangement is terminated or otherwise expires, the arrangement shall no longer be eligible to receive excess PRA revenue.

### **ZDC Hedges**

An LSE will also be able to receive excess Planning Resource Auction revenue if the LSE qualifies for a ZDC Hedge. A ZDC Hedge can result from approved firm Transmission Service Request where the source and sink are in separate LRZs or between an LRZ and an ERZ that result in required Network Upgrades. The Market Participant that funds the Transmission System upgrades that result in an increase in the CIL, as determined by the Transmission Provider, for an LRZ where the sink is located, will receive a ZDC Hedge. The Market Participant submitting the Transmission Service Request will receive one hundred percent(100%) of the MW volume of the CIL increase. ZDC Hedges will be granted based upon the order that the Transmission Provider receives Transmission Service Requests. Market Participants must submit information supporting ZDC Hedges to the Transmission Provider by November 1st prior to a Planning Year. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm Transmission Service Request. ZDC Hedges will be effective for thirty (30) years or the service life of the Transmission System facility or Network Upgrade, whichever is less.

### **Zonal Deliverability Benefit**

If there are any remaining excess PRA revenues, the Transmission Provider will distribute the remaining amounts to Deliverability Benefit Zones.

First, the Transmission Provider will subtract PRMR and ZRCs associated with HUCs and ZDC Hedges to derive an adjusted PRMR (Adjusted PRMR) and ZRC (Adjusted ZRC). Second, the Transmission Provider shall create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint. Third, the Transmission Provider, for each DBZ, will subtract the sum of Adjusted PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of the Adjusted PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon a weighted average approach. Fourth, the Transmission Provider will calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$\textit{Weighted Average Export ACP} = \frac{\sum(\textit{Net Export}_j \times \textit{ACP}_j)}{\sum \textit{Net Export}_j}$$

Where j = Each net exporting DBZ

Fifth, the Transmission Provider will calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$\textit{ZDB Credit}_k = \textit{Net Import}_k \times (\textit{ACP}_k - \textit{Weighted Average Export ACP})$$

Where  $k$  = Each net importing DBZ

Finally, the Transmission Provider will distribute the ZDB credit in each DBZ $k$  by dividing the ZDB credit by the sum of Adjusted PRMR of the LRZs within each DBZ $k$ . This distribution is a credit to the initial ACP calculated for each LRZ from the PRA.

The Transmission Provider will receive FRAP and RBDC Opt Out related revenue from Zonal Deliverability Charges. The Transmission Provider will allocate such revenue to the DBZ where the PRMR associated with the ZDC is physically located. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment. The Transmission Provider will also receive FRAP and RBDC Opt Out related revenues derived from ZRCs that would have received payments greater than the charges to the associated FRAP or RBDC Opt Out PRMR. The Transmission Provider will allocate such revenue to the DBZ where the ZRC associated with the FRAP or RBDC Opt Out is represented. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment. After calculating the ZDB rate(s), if there exists any remaining excess revenue (i.e. surplus), the surplus will be allocated back to the Deliverability Benefiting Zone(s) on a PRMR *pro-rata* basis.

Whenever an LRZ has an ACP that exceeds the System ACP because the LCR for that LRZ exceeds the sum of PRMR for LSEs within that LRZ, payments made to ZRCs in that LRZ will exceed the sum of receipts from LSEs within that LRZ plus any receipts from other LRZs related to such ZRCs. The revenue shortfall within such LRZ will be recovered from all LSEs within that LRZ on a PRMR pro-rata basis. PRMR covered by FRAPs and RBDC Opt Outs will be included in the pro-rata calculation, and the related amounts charged to the LSEs that use FRAPs and RBDC Opt Outs through this Local Clearing Requirement Charge.

**Self-Scheduling Option:**

LSEs with sufficient ZRCs within an LRZ where the LSE has forecasted Demand will be able to avoid the financial impact of that LRZ's ACP for the Final PRMR by Self-Scheduling such ZRCs into the PRA (*i.e.*, by Offering ZRCs into the PRA at a zero price so that the ZRCs will clear). For Planning Resources associated with ZRCs represented outside the LRZ where the LSE has PRMR, an LSE would also need to use the financial hedges described in Section 69A.7.7 to avoid the financial effects of potential price differences between LRZs or between an LRZ and an ERZ.

### **Installed Capacity (ICAP) Deferral Requirements and Charges**

- a. ICAP Deferral Notice. Market Participants that request ICAP deferral as provided in Sections 69A.3.1.a.2, 69A.3.1.b.2, 69A.3.1.c.2, and/or 69A.3.6.2. must provide an ICAP Deferral Notice to the Transmission Provider in writing by an officer of the company no later than February 15th prior to the Planning Year: (1) the expected ICAP value (in megawatts) from such Planning Resource and if the Planning Resource is new, the LBA or external BA where it is represented for any Season for which it wants to be eligible to offer ZRCs, (2) appropriate information validating that ICAP will be submitted to the Transmission Provider by the last business day of the Month prior to the start of any Season in which it wants to be eligible.
- b. ICAP Deferral Credit Requirements. A Market Participant that provides ICAP Deferral Notice must satisfy credit requirements by March 1st prior to the Planning Year totaling the ICAP value provided in the ICAP Deferral Notice, multiplied by ninety (90) days of daily CONE values (i.e., 90/365 times CONE) for the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs, or which are not directly connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs. If the Market Participant: (1) submits GVTC results, demonstrates deliverability, and demonstrates commercial operation, or (2) registers replacement ZRCs in accordance with Section 69A.3.1.h, then the Transmission Provider will adjust the Market

Participant's credit requirement to account for these changes within ten (10) Business Days after ICAP is submitted or replacement ZRCs have been provided to the Transmission Provider. In the event ZRCs associated with a Planning Resource for which ICAP has been deferred are unconverted in accordance with 69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred ICAP value. Then the Transmission Provider will adjust the Market Participant's ICAP value and credit requirement within ten (10) Business Days.

c. ICAP Deferral Non-Compliance Charges.

- i. A Market Participant that provides ICAP Deferral Notice and that either (1) has not submitted ICAP for such Planning Resources by the last business day of the Month prior to the start of any Season for which it has deferred, or (2) has submitted an ICAP value demonstrating fewer megawatts are available than the ICAP value submitted in the ICAP Deferral Notice, shall be assessed ICAP Deferral Non-Compliance Charges unless it completes ZRC replacement in accordance with Section 69A.3.1.h. Assessment of ICAP Deferral Non-Compliance Charges will commence on the first day of the any Season for which a Market Participant has an ICAP deferral and continue until ICAP is submitted and verified by the Transmission Provider, replacement ZRCs are registered per the BPM for Resource Adequacy, the ICAP value is forfeited, or the end of any deferred Season, whichever is earlier. Market Participants with Planning Resources subject to ICAP Deferral Non-Compliance Charges do not have to meet the applicable performance requirement as described in Sections 69A.3.9

and 69A.5 for such Resources, until such time that they are no longer subject to these charges.

- ii. ICAP Deferral Non-Compliance Charges will be calculated as follows: the amount of ICAP that has not been submitted to the Transmission Provider multiplied by the sum of the ACP and the daily CONE value (i.e., 1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs or which are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.
- iii. Distribution of ICAP Deferral Non-Compliance Charges: ICAP Deferral Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon the LSE's share of Final PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge for the Transmission Provider Region during the applicable Season.

### **Calculation of CONE and Net CONE**

- a. The CONE value shall initially be the rate proposed by the Transmission Provider in a 2012 Federal Energy Regulatory Commission filing and approved by the Commission for the Planning Year commencing on June 1, 2013. The Transmission Provider and the IMM shall consider factors, including, but not limited to: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE, the Transmission Provider and the IMM shall not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services. CONE values will be calculated for each LRZ. The Transmission Provider shall arrange for CONE values to be calculated in concert with the IMM no later than September 1 beginning on September 1, 2012. The recalculated CONE values shall be filed with the Commission annually thereafter.
- b. The Transmission Provider shall calculate Net CONE values for each LRZ. Net CONE represents the difference between CONE values and Inframarginal Rents, for the Generation Resource type used in the CONE value calculation (the Reference Resource Type). The following process will be used to estimate Net CONE:

To determine Inframarginal Rents, the most recent three Planning Years of historic data will be compiled for each Generation Resource of the Reference Resource Type operating in the Transmission Provider Region consisting of all revenues for the Generation Resource from the Transmission Provider's Energy and Operating Reserve Markets, on a per MW or MWh basis, whichever is applicable, calculated hourly, and Production Costs calculated hourly. The greater of the market revenues minus Production Costs, or zero, shall be calculated hourly, and summed across all Hours for each Planning Year, for each resource of the Reference Resource Type. Inframarginal Rents outside of two standard deviations from the sample mean are removed. The Generation Resources are then grouped into LRZs based on their location. An average Inframarginal Rents is calculated for each LRZ and then scaled using a capacity factor for each LRZ. The capacity factor is the ratio of the commitment hours of the Generation Resource of the Reference Resource Type that is committed for the maximum number of hours in the Planning Year amongst all Generation Resources of the Reference Resource Type to the average commitment hours of all Generation Resources of the Reference Resource Type that were committed in the LRZ in the Planning Year. This results in Inframarginal Rents values for each LRZ for each Planning Year, which will be averaged over a three-year period to determine an initial Inframarginal Rents for each LRZ. To determine the final Inframarginal Rents values to be used for the upcoming Planning Year, the Transmission Provider will apply a scaling factor to the initial Inframarginal Rents. The scaling factor will be based on statistical models between: a) LMPs to gas, and; b) LMPs to Inframarginal Rents. Readily available settled futures gas prices for the

upcoming Planning Year will be applied to the statistical models to calculate the scaling factor.

Each LRZ's final Inframarginal Rents are then grouped and averaged into values in the First Planning Area and Second Planning Area. The values from the First Planning Area and Second Planning Area are then subtracted from the LRZ-specific CONE values to get an estimate of Net CONE for each LRZ. For use in the PRA, Net CONE values are sorted into values in the First Planning Area and Second Planning Area.

The Transmission Provider shall arrange for Net CONE values to be calculated no later than September 1 prior to the subsequent Planning Year beginning on September 1, 2024.

The recalculated Net CONE values shall be filed with the Commission annually thereafter.

### **Use of FRAP in the Planning Resource Auction**

An LSE electing to use a Fixed Resource Adequacy Plan (FRAP) in the PRA for any Season can continue to use its existing resource planning processes to meet all or any portion of its Initial PRMR by providing the Transmission Provider with a FRAP, as described below:

- a. An LSE electing to use a FRAP for any Season must submit a FRAP for each LRZ to the Transmission Provider by the 7<sup>th</sup> Business Day of March prior to a Planning Year in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet all or any portion of the LSE's Initial PRMR for such LRZ. Market Participants submitting registrations for new and existing Load Modifying Resources can be included in the Module E Capacity Tracking Tool beginning as early as December prior to the Planning Year. Load Modifying Resources registrations submitted to the Transmission Provider will be evaluated to determine if Load Modifying Resources meet the qualification requirements. Market Participants that submit registrations by February 1 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome on or before February 21 that precedes the Planning Year. Market Participants that submit registrations between February 2 and February 15 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome at least two Business Days prior to the FRAP deadline. The Transmission Provider will make a good faith effort to notify Market Participants that submit registrations after February 15 but not later than March 1 of the outcomes of such registrations no later than the FRAP deadline. The FRAP must include the LSE's forecasted Coincident Peak Demand for each LRZ for each Season and also identify the

ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet the FRAP designated portion of its Initial PRMR and also its load ratio share of the LCR for each LRZ for each Season. The Transmission Provider will evaluate each LSE's FRAP to determine if it meets the designated portion of the LSE's Initial PRMR and the LSE's share of LCR and the Transmission Provider will notify the LSE via the MECT prior to March 15th before a Planning Year of the extent that the portion of an LSE's Initial PRMR or share of LCR for each LRZ is not covered by a submitted FRAP. The LSE will have until the PRA offer window opens to remedy any deficiencies in their FRAP for each Season.

- b. To the extent that the LSE's ZRCs satisfy the portion of the LSE's Initial PRMR for the applicable Season(s) submitted through a FRAP, (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the FRAP into the PRA, or otherwise participate in the PRA for such Season; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's Initial PRMR within such LRZ that is covered by the FRAP. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in FRAPs, as part of the Transmission Provider's reliability assessment when conducting the PRA.
- c. Any portion of an LSE's Initial PRMR not covered by the FRAP may be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is procured through the PRA.

- d. If an LSE owns or controls ZRCs that are not included in the LSE's FRAP, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.
- e. To the extent that an LSE designates ZRCs in a FRAP that are represented in the same LRZ as the LSE's Demand to meet the LSE's Initial PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.
- f. An LSE that contains ZRCs from Planning Resources that are not represented in the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

### **Use of RBDC Opt Out in the Planning Resource Auction**

An LSE electing to use the RBDC Opt Out can continue to use its existing resource planning processes to meet its Final PRMR by providing the Transmission Provider with an RBDC Opt Out, as described below:

- a. The RBDC Opt Out Lock-In Period will be three consecutive Planning Years for all Seasons. If an LSE fails to submit an RBDC Opt Out then the LSE will be required to participate in the PRA through any combination of the other Tariff-defined options, or pay the Capacity Deficiency Charge, for each Planning Year in which the LSE does not submit an RBDC Opt Out.
- b. An LSE under state jurisdiction where the State Regulatory Authority has overridden the PRM established by the Transmission Provider is not eligible to select the RBDC Opt Out.
- c. An LSE selecting the RBDC Opt Out will be required to meet its Final PRMR for the entirety of its load and losses, and its entire share of LCR for each LRZ, for each Season.
- d. An LSE must provide an initial notification of its intent to elect the RBDC Opt Out no later than January 15th prior to the upcoming Planning Year. An LSE electing the RBDC Opt Out must submit its final plan for each LRZ to the Transmission Provider by the 7<sup>th</sup> Business Day of March prior to each Planning Year during the RBDC Opt Out Lock-In Period in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet the LSE's Final PRMR, and share of LCR for each LRZ, for each Season. Market Participants

using the RBDC Opt Out must submit all registrations for new and existing resources to be used in the RBDC Opt Out through the MECT consistent with the timelines established in the Business Practices Manual for Resource Adequacy.

The RBDC Opt Out must include the LSE's seasonal forecasted Coincident Peak Demand for each LRZ and also identify the ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet its Final PRMR, and also its share of the LCR for each LRZ for each Season. The Transmission Provider will evaluate each LSE's RBDC Opt Out on an annual basis to determine if it meets the LSE's Final PRMR and the LSE's share of LCR requirements for all Seasons. The Transmission Provider will notify the LSE prior to March 15<sup>th</sup> before the applicable Planning Year whether the submitted RBDC Opt Out meets the LSE's Final PRMR, and share of LCR for each LRZ, requirement for each Season during the applicable Planning Year. The LSE must remedy any deficiencies in its RBDC Opt Out for each Season before the PRA offer window opens.

- e. The Transmission Provider will notify the RERRA(s) following the submission of an initial intent to elect the RBDC Opt Out by an LSE. RERRA(s) may elect to notify the Transmission Provider within twenty (20) Business Days whether the LSE's load subject to the RERRA's respective jurisdiction is authorized to select the RBDC Opt Out. Upon receipt of such a notification from the RERRA(s) that the LSE is not authorized to elect the RBDC Opt Out for the LSE's load subject to the RERRA's respective jurisdiction, the Transmission Provider will reject the

LSE's RBDC Opt Out for such load. If the Transmission Provider receives no notification from the RERRA(s) within the twenty (20) Business Day period, and an LSE has demonstrated that it has designated ZRCs in order to meet its Final PRMR, and share of LCR for each LRZ, for each Season, then the proposed RBDC Opt Out by the LSE will be deemed accepted by the Transmission Provider.

- f. To the extent that the LSE's ZRCs satisfy the LSE's Final PRMR for the applicable Season(s) submitted through an RBDC Opt Out, (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the RBDC Opt Out into the PRA, or otherwise participate in the PRA for such Season; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's Final PRMR within such LRZ. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in RBDC Opt Outs, as part of the Transmission Provider's reliability assessment when conducting the PRA.
- g. If an LSE owns or controls ZRCs that are not included in the LSE's RBDC Opt Out, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.
- h. To the extent that an LSE designates ZRCs in an RBDC Opt Out that are represented in the same LRZ as the LSE's Demand to meet the LSE's Final PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.
- i. An LSE that designates ZRCs from Planning Resources that are not represented in

the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

- j. LSEs that submit an RBDC Opt Out may not use any of the other options to satisfy their Final PRMR including: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process, and/or (iv) paying the Capacity Deficiency Charge to meet all or a portion of their Initial PRMR.
- k. LSEs that elect the RBDC Opt Out that do not meet their Final PRMR shall pay the RBDC Opt Out Deficiency Charge, which is 2.748 times applicable LRZ's CONE multiplied by the difference in ZRCs between the LSEs Final PRMR and the amount of ZRCs submitted as the LSEs RBDC Opt Out for each Season in which the LSE fails to meet its Final PRMR.
- l. RBDC Opt Out Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a pro rata basis, based upon their respective LSE's share of Final PRMR for the Transmission Provider Region minus the Final PRMR associated with the RBDC Opt Out Deficiency Charge. If the LRZ where LSEs incurred RBDC Opt Out Deficiency Charges failed to meet its Local Clearing Requirement ("LCR"), then RBDC Opt Out Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a pro rata basis, based upon their respective LSE's share of Final PRMR minus the Final PRMR associated with the RBDC Opt Out Deficiency Charge in such LRZ.

- m. The Transmission Provider will determine the RBDC Opt Out Adder that will be applicable for the upcoming Planning Year every year on or before December 15. The RBDC Adder applicable during the first Planning Year in which an LSE elects to use the RBDC Opt Out will apply for such LSE's entire RBDC Opt Out Lock-In Period.
- n. The Transmission Provider will determine the RBDC Opt Out Adder based on a Seasonal average of the RBDC based PRA clearing for the prior three Planning Years. If the prior year RBDC based PRA clearing is not available, simulated RBDC based PRA clearing will be used to determine the RBDC Opt Out Adder.

### **Capacity Deficiency Charge**

- a. The Transmission Provider will impose a Capacity Deficiency Charge on an LSE that has provided notification prior to the Planning Resource Auction that they will meet their Initial PRMR in part or in whole by removing Initial PRMR from the Transmission Provider's capacity construct for one or more Seasons by paying the Capacity Deficiency Charge. The Capacity Deficiency Charge will be calculated as follows: The CONE value for the LRZ(s) where the LSE has provided notice it will be meeting its Initial PRMR by paying the Capacity Deficiency Charge for each Season of the Planning Year will be multiplied by 2.748 times the Initial PRMR volume indicated by the LSE. The Capacity Deficiency Charge will be assessed to Market Participants representing their respective LSE paying the Capacity Deficiency Charge on the first Business Day after the results of the Planning Resource Auction have been published.
- b. Distribution of Capacity Deficiency Charge Revenues: A Market Participant representing an LSE that provided notice it will be meeting all or part of its Initial PRMR by paying the Capacity Deficiency Charge will not be distributed any Capacity Deficiency Charge revenues for that LSE's Initial PRMR that was met by paying the Capacity Deficiency Charge. Capacity Deficiency Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon their respective LSE's share of Initial PRMR for the Transmission Provider Region minus the Initial PRMR associated with the Capacity Deficiency Charge. If the LRZ where LSEs incurred Capacity Deficiency Charges failed to meet its Local Clearing Requirement ("LCR"), then Capacity Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a *pro rata* basis,

based upon their respective LSE's share of Initial PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge in such LRZ.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) )  
Emergency Order: Midcontinent )  
Independent System Operator )  
(MISO) )  
\_\_\_\_\_ )

Order No. 202-26-16

Exhibit to  
Motion to Intervene and Request for Rehearing and Stay of  
Public Interest Organizations

Exhibit 59

MISO 2025–26 Prelim.  
PRA Report with Final  
Results

<b>Total Installed Capacity (ICAP)</b>	Installed Capacity (ICAP) is the lesser of a resource's net demonstrated capability submitted by the resource or its interconnection service. This field provides a summation for Local Resource Zones (LRZ), External Zones, and a MISO total. Values reflect the ICAP data as available in the Module E Capacity Tracking (MECT) tool and are subject to change the closer the Planning Resource Auction (PRA) approaches.
<b>Total Seasonal Accredited Capacity (SAC)</b>	SAC is the amount of Capacity, for a given Season, in MW, assigned to a Planning Resource after accounting for its historic availability. This field provides the sum of all "SAC (Max)" in the MECT based on the various accreditation methods used for each resource type by LRZ, ERZ, and a MISO total. This the maximum potential amount of capacity that is possible to be used towards meeting Resource Adequacy requirements assuming all SAC is deliverable. It is typical for not all SAC to participate in the PRA, as it is subject to Market Participant validation and confirmation and eligibility rules. This value reflects the SAC (Max) values as available in the Module E Capacity Tracking (MECT) tool. This value also reflects DR/BTMG/ER/EE which have completed and approved registrations.
<b>Market Participant Confirmed SAC</b>	This field reflects the "SAC (Max)" values in the MECT which have been confirmed by the Market Participants. The closer the PRA approaches the more Market Participants confirm their SAC values. SAC values must be confirmed by the Market Participant before capacity can be converted into Zonal Resource Credits (ZRCs).
<b>Market Participant Converted SAC into Zonal Resource Credits (ZRC)</b>	ZRCs are the fungible unit by which the PRA is conducted. ZRCs represent a MW unit of a Planning Resource that has been converted from a MW of Seasonal Accredited Capacity to a credit in the MECT, which is eligible to be offered by a Market Participant into the PRA, to be sold bilaterally, used as replacement capacity and/or to be submitted through a Fixed Resource Adequacy Plan. Once a Market Participant has confirmed their SAC values, any portion of SAC that is deliverable (NRIS or ERIS plus firm Transmission Service) may be converted into ZRCs. This field sums all SAC values that have been converted into ZRCs by Market Participants. This value is subject to change the closer the PRA approaches due to more Market Participants converting confirmed SAC into ZRCs.
<b>Potential IMM Exclusion SAC</b>	MISO Tariff Module D Market Monitoring Mitigation Measures, Section 64.1.1 g provides circumstances Market Participants are allowed to refuse to submit ZRC Offers into the PRA. This value reflects data in the MECT which has been uploaded by the IMM for SAC MWs seeking and/or allowed to be excluded from the PRA.
<b>OASIS Attachment Y Approved Generation Retirement (MW)</b>	The sum of approved & public generation retirement MW which starts in the auction period. This data is taken from the Attachment Y posting on the MISO OASIS. This value is nameplate not SAC.
<b>Generation Suspension (MW)</b>	The sum of approved generation suspension requested for this upcoming auction period. This value is nameplate not SAC.
<b>BTMG Registrations In Progress</b>	Behind the Meter Generation (BTMG) registrations that have been entered into the MECT but not yet approved. Once approved these values can propagate to the ICAP, SAC, Confirmed SAC, and ZRC tabulations contained in this report.
<b>DR Registrations In Progress</b>	Demand Response (DR) registrations that have been entered into the MECT but not yet approved. Once approved these values can propagate to the ICAP, SAC, Confirmed SAC, and ZRC tabulations contained in this report.
<b>ER Registrations In Progress</b>	External Resources (ER) registrations that have been entered into the MECT but not yet approved. Once approved these values can propagate to the ICAP, SAC, Confirmed SAC, and ZRC tabulations contained in this report.
<b>EE Registrations In Progress</b>	Energy Efficiency (EE) registrations that have been entered into the MECT but not yet approved. Once approved these values can propagate to the ICAP, SAC, Confirmed SAC, and ZRC tabulations contained in this report.
<b>Sub Total of Registrations In Progress</b>	Sums the above registrations.
<b>Coincident Peak Forecast (CPF)</b>	This value reflects a forecasted demand submitted with Load Serving Entities (LSE) and Electric Distribution Companies (EDC) into the MECT. CPF is the demand which is forecasted to coincide with the MISO peak.
<b>Transmission Loss (TL) for CPF (MW)</b>	LBA transmission loss percentages apply to the LSE's LBA Coincident Peak Demand forecast to determine the LSE's transmission losses (MW) for the calculation of the seasonal PRMR.
<b>Initial Planning Reserve Margin Requirement (Initial PRMR)</b>	The amount of ZRCs required of each LSE with Coincident Peak Demand in an LRZ to meet the LSE's Resource Adequacy Requirements in each Season.
<b>Final Planning Reserve Margin Requirement (Final PRMR)</b>	
<b>Planning Reserve Margin Requirement (PRMR)</b>	
<b>Zonal Coincident Peak Forecast (ZCPF)</b>	This value reflects a forecasted demand submitted with Load Serving Entities (LSE) and Electric Distribution Companies (EDC) into the MECT. ZCPF is the demand which is forecasted to coincide with the zonal peak.
<b>Transmission Loss (TL) for ZCPF (MW)</b>	LBA transmission loss percentages coincident with each LRZ's seasonal Peak Demand forecast will determine the LSE's transmission losses (MW) for the calculation of LRR (MW).
<b>Local Clearing Requirement (LCR)</b>	The minimum amount of Seasonal Accredited Capacity for an LRZ that is required to meet its LOLE for each Season while fully using the Zonal Import Ability for such LRZ and accounting for controllable exports.
<b>Zonal Import Ability (ZIA)</b>	The ability of an LRZ to import capacity from areas outside of that LRZ. Equal to an LRZ's base interchange plus the LRZ's incremental ability to import generation.
<b>Capacity Export Limit (CEL)</b>	The amount of Planning Resources in MWs for an LRZ or ERZ determined by the Transmission Provider that can be reliably exported from that LRZ or ERZ for each Season.
<b>Capacity Import Limit (CIL)</b>	The amount of Planning Resources in MWs for an LRZ determined by the Transmission Provider that can be reliably imported into that LRZ for each Season..
<b>Local Reliability Requirement (LRR)</b>	The minimum amount of capacity for an LRZ to meet its LOLE for each Season, without considering transmission ties to systems outside of the LRZ.
<b>Controllable Exports</b>	Firm capacity commitments from MISO units to non-MISO load and may be committed and dispatched by MISO during emergencies.

**ACTUAL PRA DATA - PY25-26 SUMMER**

	1	2	3	4	5	6	7	8	9	10	N/C	S	Total						
PRMR																			
Coincident Peak Forecast (CPF) (MW) [M]	16,668.1	12,013.0	9,866.0	8,412.4	7,541.1	16,712.2	19,143.1	7,696.9	19,859.9	4,683.9	90,355.9	32,240.7	122,596.6						
Transmission Loss (TL) for CPF (MW) [N]	439.6	211.9	226.0	148.8	133.9	419.0	530.7	169.3	354.9	82.6	2,109.9	606.8	2,716.7						
Planning Reserve Margin (PRM %) [P]	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%						
Initial Planning Reserve Margin Requirement (Initial PRMR) (MW) [Q] = [(M+N)*(1+P)]	18,459.4	13,190.2	10,889.2	9,237.6	8,281.3	18,484.8	21,228.0	8,487.8	21,812.2	5,142.9	99,770.5	35,442.9	135,213.4						
"Effective" Planning Reserve Margin (PRM %) [R] = [S] / [(M+N)-1]	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	8.7%	8.7%	8.7%	10.1%	8.7%	9.8%						
Final Planning Reserve Margin Requirement (Final PRMR) (MW) [S]	18,843.5	13,464.4	11,116.0	9,430.1	8,453.5	18,868.9	21,669.2	8,552.6	21,978.8	5,182.3	101,845.6	35,713.7	137,559.3						
LCR																			
Zonal Coincident Peak Forecast (ZCPF) [A]	17,651.7	12,192.8	10,082.7	8,538.9	7,680.0	16,769.1	19,791.9	7,989.2	20,735.3	4,752.2									
Transmission Loss (TL) for ZCPF (MW) [B]	525.6	220.7	239.2	135.2	151.0	428.0	639.0	199.7	370.3	83.9									
Local Resource Requirement (LRR) [C]	1.195	1.135	1.318	1.280	1.301	1.262	1.138	1.350	1.136	1.447									
Zonal Import Ability (ZIA) [D]	6,023	4,370	5,460	7,757	4,117	8,366	3,569	2,358	4,361	4,474									
Controllable Exports [E]	2	0	95	768	0	285	0	210	0	0									
Capacity Import Limit (CIL) [F] = [(D+E)]	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474									
Local Clearing Requirement (LCR) [G] = [(A+B)*C-D-E]	15,696.9	9,719.3	8,049.3	2,577.8	6,071.1	13,051.7	19,681.4	8,487.0	19,615.0	2,523.8									
CIL and CEL																			
Capacity Import Limit (CIL)	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474									
Capacity Export Limit (CEL)	3,991	4,614	4,618	4,584	3,939	6,881	5,726	6,299	4,286	2,097									
	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total	
Total Installed Capacity (ICAP)	27,943.5	16,415.3	23,085.0	12,250.0	7,522.5	19,449.0	25,511.5	12,476.2	23,413.1	6,685.9	396.5	648.8	32.5	158.9	0.0	171.1	280.0	176,439.8	
Total Seasonal Accredited Capacity (SAC)	20,183.4	14,622.0	11,582.8	9,483.1	6,795.6	16,229.2	20,918.2	11,682.6	20,635.0	5,654.9	391.7	614.2	29.5	154.6	0.0	170.9	279.9	139,427.6	
Market Participant Confirmed SAC	19,992.5	14,622.0	11,470.0	9,482.9	6,795.6	16,229.2	20,916.8	11,682.6	20,629.5	5,654.1	391.7	614.2	29.5	154.6	0.0	170.9	279.9	139,116.0	
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,855.0	14,614.8	11,395.6	9,414.9	6,758.0	16,197.6	20,885.1	11,652.3	20,557.3	5,566.6	391.7	614.2	29.5	154.6	0.0	170.9	279.6	138,537.7	
Potential IMM Exclusion SAC	419.0	0.0	118.4	191.2	0.0	415.0	2.7	134.6	505.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,786.1	
OASIS Attachment Y Reported MW of Approved Generation Retirement	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0	
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	0.0	0.0	0.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0	

**ACTUAL PRA DATA - PY24-25 SUMMER**

	1	2	3	4	5	6	7	8	9	10	N/C	S	Total					
PRMR																		
Coincident Peak Forecast (CPF) (MW)	16,337.3	11,985.1	9,447.6	8,460.3	7,459.7	16,610.4	19,215.6	7,509.1	19,755.0	4,534.0	89,516.0	31,798.1	121,314.1					
Transmission Loss (TL) for CPF (MW)	815.9	304.7	448.6	166.3	152.1	421.0	568.7	225.2	325.3	87.7	2,877.3	638.2	3,515.5					
Planning Reserve Margin (PRM %) [P]	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%					
Planning Reserve Margin Requirement (PRMR) (MW)	18,697.0	13,395.8	10,786.8	9,402.8	8,297.0	18,564.5	21,564.7	8,430.5	21,887.6	5,037.7	100,708.6	35,355.8	136,064.4					
LCR																		
Zonal Coincident Peak Forecast (ZCPF)	17,023.5	12,143.1	9,543.5	8,565.0	7,532.3	16,657.2	19,867.5	7,839.9	20,497.8	4,674.0								
Transmission Loss (TL) for ZCPF (MW)	691.2	309.9	340.2	110.8	147.9	375.5	606.7	156.7	370.1	79.3								
Controllable Exports	2	0	58	892	0	284	10	164	511	0								
Local Clearing Requirement (LCR)	13,591.0	9,354.2	7,662.4	451.5	7,014.3	12,787.9	19,270.5	7,523.3	18,380.1	3,651.5								
CIL and CEL																		
Capacity Import Limit (CIL)	6,462	4,506	4,969	10,749	3,208	7,481	4,500	3,608	5,305	3,564								
Capacity Export Limit (CEL)	4,537	3,971	5,490	2,771	4,644	5,619	5,709	6,099	3,025	1,840								
	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	28,432.6	16,352.7	23,017.0	11,838.6	8,256.6	18,890.8	26,656.0	11,460.7	24,568.5	6,505.7	395.9	1,016.3	32.2	158.9	22.0	243.9	280.0	178,128.4
Total Seasonal Accredited Capacity (SAC)	21,146.8	15,260.4	11,613.6	9,273.0	7,541.9	16,191.8	22,023.2	11,002.2	22,795.8	5,704.6	392.0	998.7	29.4	156.9	22.0	241.1	280.0	144,673.4
Market Participant Confirmed SAC	20,954.3	14,895.4	11,401.8	9,153.5	7,473.5	16,191.8	22,023.2	11,002.2	22,565.8	5,704.6	392.0	998.7	29.4	156.9	22.0	241.1	280.0	143,486.2
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	20,815.5	14,836.9	11,275.8	9,059.8	7,442.1	16,191.8	21,967.3	10,979.5	22,534.5	5,704.6	392.0	994.0	29.4	156.9	22.0	239.6	280.0	142,921.7
Potential IMM Exclusion SAC	29.6	401.2	226.4	229.6	14.2	384.7	23.7	186.3	1,172.5	0.0								
OASIS Attachment Y Reported MW of Approved Generation Retirement	7.8	0.0	12.0	0.0	0.0	0.0	0.0	0.0	335.0	0.0								
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	24.9	0.0	0.0	0.0	0.0	257.9	0.0								

**ACTUAL PRA DATA POSTING - PY25-26 FALL**

	1	2	3	4	5	6	7	8	9	10	N/C	S	Total								
<b>PRMR</b>																					
Coincident Peak Forecast (CPF) (MW) [M]	14,539.8	10,319.8	8,601.1	7,610.5	6,723.2	15,049.4	17,272.0	6,835.8	18,495.8	4,402.6	80,115.8	29,734.2	109,850.0								
Transmission Loss (TL) for CPF (MW) [N]	508.5	199.4	258.1	179.2	151.1	563.9	564.4	143.6	283.8	73.1	2,424.6	500.5	2,925.1								
Planning Reserve Margin (PRM) % [P]	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%								
Initial Planning Reserve Margin Requirement (Initial PRMR) (MW) [Q] = [(M+N)*(1+P)]	17,290.4	12,086.4	10,179.1	8,950.4	7,898.3	17,939.5	20,493.9	8,019.3	21,578.1	5,142.6	94,838.0	34,740.0	129,578.0								
"Effective" Planning Reserve Margin (PRM) % [R] = [S] / [(M+N)-1]	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	15.2%	15.2%	15.2%	18.4%	15.2%	17.5%								
Final Planning Reserve Margin Requirement (Final PRMR) (MW) [S]	17,811.7	12,450.6	10,486.1	9,220.3	8,136.3	18,480.2	21,111.9	8,037.5	21,627.0	5,154.3	97,697.1	34,818.7	132,515.8								
<b>LCR</b>																					
Zonal Coincident Peak Forecast (ZCPF) [A]	15,376.9	10,533.0	8,891.0	7,750.0	6,851.7	15,178.9	17,957.3	7,245.2	19,391.5	4,449.4											
Transmission Loss (TL) for ZCPF (MW) [B]	485.7	210.1	301.2	99.8	134.5	581.3	617.3	137.6	395.3	101.4											
Local Resource Requirement (LRR) [C]	1,288	1,222	1,537	1,320	1,365	1,312	1,255	1,469	1,198	1,557											
Zonal Import Ability (ZIA) [D]	5,688	6,537	7,704	7,013	4,679	8,672	5,115	5,675	4,741	4,508											
Controllable Exports [E]	52	0	93	760	0	280	0	164	0	0											
Capacity Import Limit (CIL) [F] = [(D+E)]	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508											
Local Clearing Requirement (LCR) [G] = [(A+B)*C-D-E]	14,691.0	6,591.1	6,331.4	2,588.7	4,857.2	11,725.4	18,196.1	5,006.3	18,963.6	2,577.6											
<b>CIL and CEL</b>																					
Capacity Import Limit (CIL)	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508											
Capacity Export Limit (CEL)	6,115	4,259	5,831	4,309	5,816	5,191	5,168	4,055	4,173	3,164											
	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total			
Total Installed Capacity (ICAP)	26,744.9	16,212.3	23,081.8	12,151.3	7,663.1	19,066.4	24,921.1	12,268.7	23,435.7	6,667.6	375.1	670.1	32.6	158.9	0.0	171.1	280.0	173,900.7			
Total Seasonal Accredit Capacity (SAC)	19,481.4	14,342.5	14,114.0	9,096.4	6,913.6	15,751.7	19,559.1	11,125.1	21,312.1	5,634.1	372.1	651.0	30.4	154.7	0.0	170.3	277.4	138,985.9			
Market Participant Confirmed SAC	19,248.9	14,342.5	13,864.5	9,096.3	6,913.6	15,751.7	19,557.8	11,125.1	21,312.1	5,634.1	372.1	651.0	30.4	154.7	0.0	170.3	277.4	138,502.5			
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,043.7	14,332.9	13,767.3	9,068.2	6,855.9	15,717.2	19,518.6	11,081.4	21,242.7	5,546.6	372.1	650.0	30.4	154.0	0.0	170.3	272.1	137,824.1			
Potential IMM Exclusion SAC	391.4	0.0	126.4	183.4	0.0	649.8	3.5	88.9	550.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,993.5			
OASIS Attachment Y Reported MW of Approved Generation Retirement	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0			
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	0.0	0.0	0.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0			

**ACTUAL PRA DATA - PY24-25 FALL**

	1	2	3	4	5	6	7	8	9	10	N/C	S	Total								
<b>PRMR</b>																					
Coincident Peak Forecast (CPF) (MW)	13,807.4	10,324.4	8,511.7	7,534.4	6,839.1	15,271.0	17,008.8	6,481.7	17,834.0	4,088.9	79,296.8	28,404.6	107,701.4								
Transmission Loss (TL) for CPF (MW)	425.0	184.5	195.6	96.6	139.8	289.7	410.2	175.0	251.4	70.6	1,741.4	497.0	2,238.4								
Planning Reserve Margin (PRM) %	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%								
Planning Reserve Margin Requirement (PRMR) (MW)	16,253.6	12,001.3	9,943.9	8,714.7	7,969.8	17,770.1	19,892.6	7,602.0	20,653.4	4,750.0	92,546.0	33,005.4	125,551.4								
<b>LCR</b>																					
Zonal Coincident Peak Forecast (ZCPF)	14,773.2	10,543.9	8,715.6	7,606.5	6,911.9	15,347.7	17,752.9	6,970.4	18,780.9	4,246.3											
Transmission Loss (TL) for ZCPF (MW)	481.0	191.1	226.2	154.3	168.2	331.9	430.2	139.3	328.0	83.8											
Controllable Exports	2.0	0.0	62.0	895.0	0.0	298.0	10.0	195.0	501.0	0											
Local Clearing Requirement (LCR)	12,336.9	7,152.3	5,280.7	3,673.5	6,416.4	10,750.3	19,443.3	5,499.1	16,630.6	2,482.3											
<b>CIL and CEL</b>																					
Capacity Import Limit (CIL)	6,502	5,719	6,746	6,594	3,786	8,959	4,400	5,137	6,109	4,736											
Capacity Export Limit (CEL)	5,711	4,512	6,956	3,906	5,402	3,514	5,381	4,115	2,803	2,889											
	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total			
Total Installed Capacity (ICAP)	27,927.1	16,310.6	22,865.2	11,492.0	8,156.9	18,784.9	26,047.0	11,303.9	24,555.3	6,497.0	372.7	1,463.3	32.3	158.9	22.0	242.9	280.0	176,512.0			
Total Seasonal Accredit Capacity (SAC)	20,210.5	14,875.4	11,224.6	8,895.6	7,415.8	16,084.2	21,193.1	10,546.4	22,803.6	5,807.4	370.4	1,371.4	30.1	153.9	22.0	240.2	280.0	141,524.6			
Market Participant Confirmed SAC	20,083.5	14,638.4	11,024.7	8,776.9	7,348.2	16,084.2	21,193.1	10,546.4	22,523.3	5,807.4	370.4	1,371.4	30.1	153.9	22.0	240.2	280.0	140,494.1			
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,938.5	14,575.2	10,875.3	8,668.7	5,562.3	16,084.2	21,072.8	10,544.3	22,502.8	5,807.4	370.4	1,362.3	30.1	153.9	22.0	237.7	280.0	138,087.9			
Potential IMM Exclusion SAC	80.4	276.9	225.2	252.3	1,754.7	604.6	95.9	120.2	1,686.2	0.0											
OASIS Attachment Y Reported MW of Approved Generation Retirement	4.9	0.0	6.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0											
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	25.6	0.0	0.0	0.0	0.0	262.4	0.0											

\*Disclaimer - Values displayed on this posting demonstrates progress to date by Market Participants and MISO and is subject to change. The capacity displayed is not a prediction of final capacity values prior to the upcoming Planning Resource Auction. The capacity that will ultimately participate in the upcoming auction are still in progress. Capacity changes will likely stem from: Behind the Meter Generators (BTMG) / Demand Response (DR) / External Resources (ER) / Energy Efficiency (EE) programs that are still in the process of completing registration, Market Participants resolution of GVTC extensions, Market Participants utilizing ICAP Deferral, March Commercial Model updates and the March 14 deadline for Market Participants to request the IMM grant PRA exclusions as outlined in Module D Section 64.1.1 paragraph g. As per the Tariff Module E-1 Section 68A.4 and BPM-011 Appendix K, final Preliminary PRA data posting will be posted by March 25.

Data Export Time: 3/18/2025

Total (row 20), Confirmed (row 21) and Converted (row 22) SAC do not include the following: Potential IMM Exclusions (row 23), Retirements (row 24), and Suspensions (row 25).

**ACTUAL PRA DATA POSTING - PY25-26 WINTER**

	1	2	3	4	5	6	7	8	9	10	N/C	S	Total					
PRMR																		
Coincident Peak Forecast (CPF) (MW) [M]	14,605.7	8,960.7	8,087.2	7,059.4	6,547.0	14,766.6	13,277.3	7,076.0	18,032.2	4,211.9	73,303.9	29,320.1	102,624.0					
Transmission Loss (TL) for CPF (MW) [N]	448.2	152.2	265.1	161.5	171.7	384.4	340.6	141.6	434.0	126.0	1,923.7	701.6	2,625.3					
Planning Reserve Margin (PRM %) [P]	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%	18.4%					
Initial Planning Reserve Margin Requirement (Initial PRMR) (MW) [Q] = [(M+N)*(1+P)]	17,823.8	10,789.8	9,889.1	8,549.5	7,954.8	17,939.1	16,123.6	8,545.6	21,864.3	5,136.1	89,069.7	35,546.0	124,615.7					
"Effective" Planning Reserve Margin (PRM %) [R] = [S] / [(M+N)-1]	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%	27.3%	27.3%	27.3%	23.3%	27.3%	24.5%					
Final Planning Reserve Margin Requirement (Final PRMR) (MW) [S]	18,565.6	11,238.7	10,300.8	8,905.4	8,285.9	18,685.6	16,794.7	9,189.1	23,510.9	5,522.8	92,776.8	38,222.7	130,999.5					
LCR																		
Zonal Coincident Peak Forecast (ZCPF) [A]	14,993.5	9,059.3	8,175.6	7,138.1	6,669.4	14,931.7	13,626.6	7,272.5	18,931.9	4,188.5								
Transmission Loss (TL) for ZCPF (MW) [B]	506.9	159.9	332.6	116.0	162.1	306.3	376.3	152.6	352.4	106.4								
Local Resource Requirement (LRR) [C]	1.267	1.353	1.632	1.186	1.254	1.247	1.447	1.566	1.297	1.628								
Zonal Import Ability (ZIA) [D]	5,575	6,435	5,785	6,457	4,922	7,690	4,762	3,432	4,418	3,458								
Controllable Exports [E]	602	87	92	775	0	237	0	181	0	0								
Capacity Import Limit (CIL) [F] = [(D+E)]	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458								
Local Clearing Requirement (LCR) [G] = [(A+B)*C-D-E]	13,462.0	5,951.6	8,008.4	1,371.4	3,644.7	11,074.8	15,500.2	8,014.7	20,593.7	3,534.1								
CIL and CEL																		
Capacity Import Limit (CIL)	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458								
Capacity Export Limit (CEL)	2,991	4,706	7,388	4,756	4,814	1,674	5,712	3,602	3,618	2,028								
Total Installed Capacity (ICAP)	26,213.3	14,989.9	23,093.1	11,021.5	7,399.4	18,394.5	24,923.1	11,995.8	24,737.2	6,681.8	420.1	808.7	33.8	158.9	0.0	171.1	280.0	171,322.2
Total Seasonal Accredited Capacity (SAC)	20,268.4	13,300.9	12,472.8	7,767.5	6,379.1	14,842.1	20,055.5	10,952.4	22,466.0	5,977.6	418.8	757.7	31.2	155.3	0.0	169.9	277.7	136,292.9
Market Participant Confirmed SAC	20,043.5	13,300.9	12,328.3	7,767.1	6,379.1	14,842.1	20,053.7	10,952.4	22,466.0	5,977.6	418.8	757.7	31.2	155.3	0.0	169.9	277.7	135,921.3
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,849.7	13,286.5	12,171.9	7,658.9	6,362.0	14,734.3	19,958.4	10,913.2	22,435.3	5,968.8	418.8	757.7	31.2	155.3	0.0	169.9	273.0	135,144.9
Potential IMM Exclusion SAC	1,042.7	629.6	83.2	198.1	0.0	845.2	39.2	105.5	502.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,446.2
OASIS Attachment Y Reported MW of Approved Generation Retirement	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	0.0	0.0	0.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0

2025-26 WINTER

**ACTUAL PRA DATA - PY24-25 WINTER**

	1	2	3	4	5	6	7	8	9	10	N/C	S	Total					
PRMR																		
Coincident Peak Forecast (CPF) (MW)	14,085.5	8,964.9	7,918.2	7,076.2	6,328.1	14,613.6	13,217.8	6,881.4	17,102.8	3,926.1	72,204.3	27,910.3	100,114.6					
Transmission Loss (TL) for CPF (MW)	457.3	222.2	423.8	223.1	245.3	441.7	413.1	165.2	317.8	98.1	2,426.5	581.1	3,007.6					
Planning Reserve Margin (PRM %) [P]	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4	27.4					
Planning Reserve Margin Requirement (PRMR) (MW)	18,527.8	11,703.9	10,628.0	9,299.5	8,374.5	19,180.0	17,365.6	8,977.1	22,193.8	5,126.6	95,079.3	36,297.5	131,376.8					
LCR																		
Zonal Coincident Peak Forecast (ZCPF)	14,438.3	9,166.1	7,919.6	7,122.7	6,397.0	14,833.3	13,542.1	7,387.5	17,800.2	4,194.7								
Transmission Loss (TL) for ZCPF (MW)	585.6	160.5	291.6	231.5	247.8	448.7	305.4	140.3	338.6	112.2								
Controllable Exports	2.0	0.0	68.0	896.0	0.0	246.0	0.0	102.0	577.0	0								
Local Clearing Requirement (LCR)	16,971.5	7,189.2	10,803.7	3,132.9	4,061.6	10,219.0	17,596.9	7,379.4	18,888.3	4,809.1								
CIL and CEL																		
Capacity Import Limit (CIL)	4,693	5,523	5,668	6,707	4,477	8,532	4,656	4,364	5,200	3,219								
Capacity Export Limit (CEL)	5,174	4,772	9,011	4,674	6,229	1,401	5,753	5,780	2,323	2,993								
Total Installed Capacity (ICAP)	27,590.2	15,940.1	23,123.8	11,102.2	8,382.1	18,724.5	26,387.9	11,809.3	25,616.2	6,683.8	410.1	1,644.2	33.5	158.9	22.0	161.7	280.0	178,070.4
Total Seasonal Accredited Capacity (SAC)	25,255.0	15,161.3	16,173.9	8,821.5	7,227.8	16,347.1	23,218.5	10,808.6	24,346.8	6,366.9	409.0	1,541.2	30.9	153.1	22.0	231.2	280.0	156,394.8
Market Participant Confirmed SAC	24,847.9	14,764.0	15,701.7	8,702.8	7,162.0	16,347.1	23,218.5	10,808.6	24,092.2	6,366.9	409.0	1,541.2	30.9	153.1	22.0	231.2	280.0	154,679.1
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	24,467.0	14,687.6	15,339.4	8,459.7	5,995.9	16,297.5	23,082.8	10,788.9	23,983.5	6,366.9	409.0	1,504.4	30.9	153.1	22.0	231.1	280.0	152,099.7
Potential IMM Exclusion SAC	682.9	539.4	258.5	233.8	1,154.7	339.2	21.3	102.3	1,240.3	0.0								
OASIS Attachment Y Reported MW of Approved Generation Retirement	19.3	0.0	29.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0								
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	19.5	0.0	0.0	0.0	0.0	299.5	0.0								

2024-25 WINTER

\*Disclaimer - Values displayed on this posting demonstrates progress to date by Market Participants and MISO and is subject to change. The capacity displayed is not a prediction of final capacity values prior to the upcoming Planning Resource Auction. The capacity that will ultimately participate in the upcoming auction are still in progress. Capacity changes will likely stem from: Behind the Meter Generators (BTMG) / Demand Response (DR) / External Resources (ER) / Energy Efficiency (EE) programs that are still in the process of completing registration, Market Participants resolution of GVTC extensions, Market Participants utilizing ICAP Deferral, March Commercial Model updates and the March 14 deadline for Market Participants to request the IMM grant PRA exclusions as outlined in Module D Section 64.1.1 paragraph g. As per the Tariff Module E-1 Section 68A.4 and BPM-011 Appendix K, final Preliminary PRA data posting will be posted by March 25.

Data Export Time: 3/18/2025

Total (row 20), Confirmed (row 21) and Converted (row 22) SAC do not include the following: Potential IMM Exclusions (row 23), Retirements (row 24), and Suspensions (row 25).

**ACTUAL PRA DATA POSTING - PY25-26 SPRING**

	1	2	3	4	5	6	7	8	9	10	N/C	S	Total						
PRMR																			
Coincident Peak Forecast (CPF) (MW) [M]	13,680.6	9,463.7	7,677.0	6,436.5	5,989.1	13,813.9	15,448.8	6,254.3	17,408.2	4,053.1	100,305.1	27,715.6	100,225.2						
Transmission Loss (TL) for CPF (MW) [N]	578.1	232.1	425.2	190.8	162.7	438.4	395.8	112.6	261.3	71.2	2,858.0	445.1	2,868.2						
Planning Reserve Margin (PRM %) [P]	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%	25.3%						
Initial Planning Reserve Margin Requirement (Initial PRMR) (MW) [Q] = [(M+N)*(1+P)]	17,866.7	12,149.2	10,152.2	8,304.0	7,707.9	17,858.6	19,853.2	7,977.8	22,139.8	5,167.9	93,891.8	35,285.5	129,177.3						
"Effective" Planning Reserve Margin (PRM %) [R] = [S] / [(M+N)-1]	27.5%	27.5%	27.5%	27.5%	27.5%	27.5%	27.5%	25.0%	25.0%	25.0%	-7.4%	25.0%	26.8%						
Final Planning Reserve Margin Requirement (Final PRMR) (MW) [S]	18,174.4	12,358.5	10,327.4	8,447.4	7,840.9	18,166.5	20,195.4	7,955.9	22,079.3	5,153.8	95,510.5	35,189.0	130,699.5						
LCR																			
Zonal Coincident Peak Forecast (ZCPF) [A]	14,267.9	9,687.1	7,906.8	6,514.3	6,108.0	13,849.6	15,983.2	6,525.6	18,759.9	4,141.9									
Transmission Loss (TL) for ZCPF (MW) [B]	414.2	212.6	181.2	151.8	165.7	440.1	407.7	110.9	315.6	77.2									
Local Resource Requirement (LRR) [C]	1,283	1,331	1,588	1,495	1,459	1,388	1,319	1,587	1,292	1,788									
Zonal Import Ability (ZIA) [D]	6,396	6,439	7,726	7,373	4,453	9,176	5,166	6,085	4,855	4,365									
Controllable Exports [E]	202	0	103	769	0	281	0	204	0	0									
Capacity Import Limit (CIL) [F] = [(D+E)]	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365									
Local Clearing Requirement (LCR) [G] = [(A+B)*C-D-E]	12,239.1	6,737.5	5,014.7	1,823.8	4,700.3	10,377.1	16,453.6	4,243.1	19,790.5	3,178.8									
CIL and CEL																			
Capacity Import Limit (CIL)	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365									
Capacity Export Limit (CEL)	5,083	6,119	5,936	5,111	5,797	6,425	5,499	3,520	4,146	3,072									
	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total	
Total Installed Capacity (ICAP)	25,715.0	16,013.6	23,303.8	12,246.7	7,052.1	18,984.1	24,160.5	12,236.7	24,512.1	6,649.8	393.3	697.6	33.5	158.9	0.0	171.1	280.0	172,608.8	
Total Seasonal Accredited Capacity (SAC)	19,155.6	14,643.1	12,684.3	9,409.4	6,193.5	15,989.2	19,498.0	11,745.7	21,282.7	5,983.6	392.3	638.4	30.8	158.5	0.0	170.0	278.7	138,253.8	
Market Participant Confirmed SAC	18,954.5	14,643.1	12,497.2	9,408.9	6,193.5	15,958.5	19,496.3	11,745.7	21,282.7	5,983.6	392.3	638.4	30.8	158.5	0.0	170.0	278.7	137,832.7	
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	18,755.9	14,588.0	12,420.2	9,281.0	6,131.3	15,886.1	19,452.1	11,709.3	21,172.2	5,896.1	392.3	638.4	30.8	158.5	0.0	170.0	276.2	136,958.4	
Potential IMM Exclusion SAC	1,051.0	257.2	87.3	220.2	655.1	1,388.2	743.4	565.8	604.8	155.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,678.4	
OASIS Attachment Y Reported MW of Approved Generation Retirement	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.0	
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	0.0	0.0	0.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0	

**ACTUAL PRA DATA - PY24-25 SPRING**

	1	2	3	4	5	6	7	8	9	10	N/C	S	Total					
PRMR																		
Coincident Peak Forecast (CPF) (MW)	13,193.5	9,451.0	7,650.3	6,158.0	5,953.1	13,824.5	15,167.2	6,100.0	17,149.2	4,051.0	71,397.6	27,300.2	98,697.8					
Transmission Loss (TL) for CPF (MW)	394.8	164.1	235.9	141.1	133.3	261.4	357.7	128.1	266.9	79.8	1,688.3	474.8	2,163.1					
Planning Reserve Margin (PRM %) [P]	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%					
Planning Reserve Margin Requirement (PRMR) (MW)	17,216.9	12,182.5	9,991.8	7,981.1	7,711.2	17,846.6	19,670.2	7,891.0	22,065.7	5,233.6	92,600.3	35,190.3	127,790.6					
LCR																		
Zonal Coincident Peak Forecast (ZCPF)	13,886.7	9,657.6	7,811.1	6,200.8	6,023.0	13,903.9	15,702.2	6,453.3	18,303.8	4,274.6								
Transmission Loss (TL) for ZCPF (MW)	325.3	176.3	257.7	142.1	117.6	268.6	375.9	135.6	284.7	84.5								
Controllable Exports	2.0	0.0	58.0	899.0	0.0	315.0	0.0	165.0	515.0	0.0								
Local Clearing Requirement (LCR)	13,944.7	8,369.6	5,781.3	4,559.9	6,043.5	11,385.5	16,372.2	4,413.1	18,684.1	3,558.4								
CIL and CEL																		
Capacity Import Limit (CIL)	4,943	5,034	6,572	6,982	3,892	8,045	4,883	6,195	6,113	4,628								
Capacity Export Limit (CEL)	6,318	4,601	5,815	5,102	4,984	3,414	5,601	4,865	4,298	2,740								
	1	2	3	4	5	6	7	8	9	10	E20	E22	E23	E24	E26	E27	E28	Total
Total Installed Capacity (ICAP)	27,641.8	16,729.6	23,073.6	11,969.9	8,316.6	19,258.1	26,423.1	11,983.9	24,986.0	6,702.4	378.1	1,511.4	32.7	158.9	22.0	239.9	280.0	179,707.9
Total Seasonal Accredited Capacity (SAC)	20,182.1	15,274.4	11,357.2	9,499.6	7,337.0	16,759.3	21,524.6	11,741.1	23,303.0	6,182.4	376.7	1,455.8	30.1	155.5	22.0	235.7	280.0	145,716.5
Market Participant Confirmed SAC	19,608.0	15,010.6	11,140.9	9,377.7	7,272.2	16,759.3	21,524.6	11,741.1	23,011.7	6,182.4	376.7	1,455.8	30.1	155.5	22.0	235.7	280.0	144,184.3
Market Participant Converted UCAP into Zonal Resource Credits (ZRC)	19,427.7	14,932.0	10,995.7	9,255.7	5,862.3	16,719.3	21,268.4	11,722.4	22,974.7	6,182.4	376.7	1,437.0	30.1	155.5	22.0	233.2	280.0	141,875.1
Potential IMM Exclusion SAC	263.8	308.2	213.3	611.4	1,348.7	1,691.4	447.7	178.7	2,151.4	0.0								
OASIS Attachment Y Reported MW of Approved Generation Retirement	7.4	0.0	9.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0								
Total Effective Suspension MW in Auction Period	0.0	0.0	0.0	34.7	0.0	0.0	0.0	0.0	321.8	0.0								

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Data Export Time: 3/18/2025

Total (row 20), Confirmed (row 21) and Converted (row 22) SAC do not include the following: Potential IMM Exclusions (row 23), Retirements (row 24), and Suspensions (row 25).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) )  
Emergency Order: Midcontinent )  
Independent System Operator )  
(MISO) )  
\_\_\_\_\_ )

Order No. 202-26-16

Exhibit to  
Motion to Intervene and Request for Rehearing and Stay of  
Public Interest Organizations

# Exhibit 60

## MISO Tariff Section 38.2.7

### **38.2.7 Generation Suspension, Generation Retirement, and System Support Resources**

#### **a. Generator or SCU Notification of Change in Status.**

##### **(i) Notification Procedures for Units.**

An owner of a Generation Resource, Synchronous Condenser Unit (SCU), or a Generator that is directly interconnected to the Transmission System but is Pseudo-tied out of the Transmission Provider's Balancing Authority Area that is planning to Suspend operations of all or any portion of that resource must notify the Transmission Provider of such a plan by submitting a completed Attachment Y Notice to the Transmission Provider. This notification provision also applies to a Generation Resource connected to the underlying lower voltage facilities within Transmission Provider region and to Generation Resources that are not directly interconnected to the Transmission System, but are External Resources that are Pseudo-tied into the Transmission Provider's Balancing Authority Area. The Transmission Provider shall coordinate with the entity to which the External Resource is directly connected to determine whether the External Resource is necessary for reliability of the Transmission System, in accordance with applicable coordinated planning provisions between the Transmission Provider and the regional planning entity to which the External Resource is interconnected.

The owner of a Generation Resource or SCU shall submit an Attachment Y Notice to the Transmission Provider at least four full Quarterly Study Periods prior to changing to Suspend status, unless the Generation Resource or SCU is inoperable due to Forced Outage in which case Attachment Y Notice must be submitted to the Transmission Provider at least thirty (30) days prior to changing to Suspend status. A Generation Resource that has undergone a Reliability Assessment Study that performs an Attachment Y equivalent study as part of the Generating

Facility Replacement process and all reliability violations identified through such study have been mitigated must submit an Attachment Y Notice to the Transmission Provider at least thirty (30) days prior to changing to Suspend status. The owner of a Pseudo-tied out Generator shall submit an Attachment Y Notice to the Transmission Provider at least thirty (30) days prior to the anticipated effective date of change of status.

A Generation Resource or SCU that is inoperable due to Forced Outage or a Pseudo-tied out Generator shall not be designated as an SSR Unit. The provisions for time limitations on suspension within Section 38.2.7 shall apply to a Generation Resource or SCU that is inoperable due to Forced Outage and a Pseudo-tied out Generator.

A Generation Resource that is designated as a Blackstart Unit by a Transmission Operator in its System Restoration Plans shall not be designated as an SSR Unit to solely provide Blackstart Service. However, the Transmission Provider may determine that SSR Unit status is justified if such Generation Resource is required to maintain the reliability of the Transmission System based on its Attachment Y Reliability Study. Section 38.2.7 shall not modify or alter a Transmission Operator's obligations under the Tariff to identify Blackstart Units that are included in its System Restoration Plans, or a Blackstart Unit Owner's obligations to comply with the terms of any Blackstart Service agreement, in accordance with Schedule 33, or the requirements of Commission approved reliability standards.

The following exception applies to the Generation Suspension, Generation Retirement and System Support Resource (SSR) provisions in Section 38.2.7: The owner of a Generation Resource or SCU that requests a Generator Planned Outage or submits a Generator Forced Outage through the Transmission Provider's outage scheduling system (Control Room

Operations Window – CROW or its successor) does not need to submit an Attachment Y Notice to the Transmission Provider if the request does not involve a change of status to Suspend.

An owner of a Generation Resource, SCU, or a Pseudo-tied out Generator certifies by submitting an Attachment Y Notice that it has elected to Suspend such resource and the Attachment Y Notice shall be executed by an officer of such owner attesting to that claim. The decision to Suspend may be modified by rescission as specifically provided in this Section 38.2.7.

An owner may not submit a new Attachment Y Notice to Suspend that supersedes a prior notification unless the prior Attachment Y Notice is rescinded. The new Attachment Y Notice shall be submitted to the Transmission Provider at least four full Quarterly Study Periods prior to changing to Suspend status.

**(ii) Confidentiality of Attachment Y Notice.**

The Transmission Provider shall treat all Attachment Y Notices as Confidential Information unless the Attachment Y Reliability Study is complete and any of the following occurs: 1) the owner has elected to waive its rescission rights; 2) the resource fails to return to operation before the period for rescission has lapsed; 3) public release is required under Section 38.2.7.b in order to evaluate the need for an SSR Agreement; or 4) the information is otherwise publicly disclosed by the owner of a Generation Resource, SCU, or a Pseudo-tied out Generator. The Transmission Provider shall promptly post on OASIS that an Attachment Y Notice was submitted, along with the effective date of retirement, under the first three of these circumstances.

**(iii) Notification of the Outage Scheduler After Submittal of Attachment Y**

**Notice.**

After receipt of an Attachment Y Notice, the Transmission Provider shall schedule such outage notification through the Transmission Provider's Control Room Operations Window ("CROW") outage scheduling system, or successor system, to coordinate the outage planning of a Generation Resource or SCU through CROW, on behalf of the owner.

**b. SSR Unit Procedures.**

System Support Resource (SSR) procedures provide a mechanism for the Transmission Provider to enter into agreements with Market Participants that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that are required by the Transmission Provider to maintain reliability of the Transmission System, if all or a specified portion of the capacity of such Generation Resources or SCUs would otherwise either Retire or Suspend. SSR Agreements are a last-resort measure to address a reliability issue on the Transmission System facilities under the functional control of the Transmission Provider and shall only be entered into once all potential SSR Agreement alternatives have been examined.

An owner of a Generation Resource or SCU must submit all necessary information to enable the Transmission Provider to evaluate whether SSR Unit status is appropriate for such Generation Resource or SCU. If, after completing a reliability study (Attachment Y Reliability Study) and analyzing potential alternatives (Attachment Y Alternatives Study), the Transmission Provider determines that SSR Unit status is justified for a Generation Resource or SCU, that is not subject to an exception under Section 38.2.7.a, then the Transmission Provider and Market Participant of such Generation Resource or SCU shall enter into an SSR Agreement, in

accordance with the Attachment Y-1 form of agreement. The SSR Unit will be operated in accordance with the terms of the SSR Agreement, which contains detailed terms and conditions regarding operation and compensation of such Generation Resource or SCU. The Transmission Provider shall periodically review the reliability requirements of the Transmission Provider Region and shall determine which, if any, SSR Agreements should be extended.

The Transmission Provider shall use reasonable efforts to respond to the owner within 150 Calendar Days after the start of the individual Attachment Y Reliability Study, regarding whether the subject of an Attachment Y Notice appears to be required for transmission system reliability, unless an alternative date is agreed to by the owner and the Transmission Provider.

If the Attachment Y Reliability Study determines that a reliability concern exists, and a response is provided by the Transmission Provider to the owner, the Transmission Provider shall promptly post on OASIS: (1) that an Attachment Y Notice was submitted; (2) that the Transmission Provider's Attachment Y Reliability Study concluded that the Generation Resource or SCU was required for the reliability of the Transmission System; (3) the draft report on the Attachment Y Reliability Study with the CEII information redacted from the report; and (4) how the associated SSR Unit costs would be allocated in the event that the Generation Resource or SCU is required to provide service under an SSR designation.

The Transmission Provider shall discontinue Confidential treatment of an Attachment Y Notice and Attachment Y Reliability Study in the event that the Attachment Y Reliability Study results determine that the Generation Resource or SCU is required to maintain system reliability and would be eligible for treatment as an SSR Unit. The Transmission Provider may use information related to Retire or Suspend status in its Transmission Planning processes (pursuant

to Attachment FF and the Transmission Planning BPM) and in its Generator Interconnection process (pursuant to Attachment X and the Generation Interconnection BPM), provided that recipients of the information have signed appropriate Non-Disclosure Agreements with the Transmission Provider.

**c. Evaluation of Need for the SSR Designation.**

The Transmission Provider will perform an Attachment Y Reliability Study to determine whether the Generation Resource or SCU is necessary for the reliability of the Transmission System based on the analyses described in this section and the criteria set forth in the Business Practices Manuals, but will not determine in this initial analysis the available alternatives to designating the Generation Resource or SCU as an SSR Unit. The Transmission Provider will start the study process at the beginning of the Quarterly Study Period. A request to Suspend operations submitted in an Attachment Y Notice received during a quarter will be studied individually, beginning in the subsequent Quarterly Study Period.

In collaboration with the affected Transmission Owners, the Transmission Provider will cause an evaluation to be performed of transmission system conditions (an Attachment Y Reliability Study) that result from the change in status of the unit(s) subject to Attachment Y notification requirements. The evaluation will consider the performance of the transmission system to determine if thermal or voltage violations of applicable NERC Standards and Transmission Owner planning criteria occur when the unit is offline compared to conditions when the unit is online. The scope of this evaluation will include a steady state analysis, and may require analyses of stability and import limitations for the particular study area. Study cases will be derived from approved MTEP models that are representative of the period of time for

which the suspension of the unit(s) is requested, and will include models that represent near-term and/or longer-term scenarios as appropriate for the study period. Models that are developed to reflect both the online and offline status of the unit being evaluated will be analyzed to compare the differences in results to determine the impact of the unit on the transmission system. The results of the evaluation will be reviewed with the participating Transmission Owners to verify the Transmission Provider's findings and to evaluate proposed solutions that should be considered to address the reliability issues. The need to retain a unit(s) as a System Support Resource, absent implementation of a feasible alternative, shall be determined by the presence of unresolved reliability violations on the Transmission System that is under the functional control of the Transmission Provider.

The Transmission Provider shall post the determination of reliability need on the Transmission Provider's OASIS and shall: (1) begin negotiations of a potential SSR Agreement with the Market Participant owning or operating the Generation Resource or SCU; and (2) use reasonable efforts to hold a stakeholder meeting pursuant to Attachment FF within thirty (30) Calendar Days to review alternatives to the potential SSR Unit designation or designations (if multiple Attachment Y Notices apply). The Transmission Provider will schedule subsequent stakeholder meetings as needed. The Transmission Provider shall complete the Attachment Y Alternatives Study within four full Quarterly Study Periods after receipt of an Attachment Y Notice, if the Attachment Y Notice provides only four full Quarterly Study Periods of advance notification, unless otherwise agreed to by the owner of the potential SSR Unit. If no alternative is identified as available by the Attachment Y Notice date to Suspend, then the Transmission

Provider shall file the SSR Agreement with an effective date as of the Attachment Y Notice date to Suspend.

Before entering into an SSR Agreement with any Generation Resource or SCU, the Transmission Provider shall assess, in an open and transparent planning process in accordance with the provisions of the Transmission Expansion Planning Protocol Attachment FF to the Tariff, feasible alternatives to the proposed SSR Agreement. The list of alternatives to SSR Unit status that the Transmission Provider shall consider and expeditiously approve as applicable include (depending upon the type of reliability concern identified): (i) redispatch/reconfiguration through operator instruction; (ii) remedial action plans; (iii) special protection schemes initiated upon Generation Resource trips or unplanned Transmission Outages; (iv) contracted demand response or Generator alternatives; and (v) transmission expansions. Consistent with Section B.1.b of Attachment FF, the Transmission Provider will review and evaluate alternatives to an SSR Agreement on a comparable basis and select the most appropriate solution. Comparability includes the ability of the Transmission Provider to require contractual assurances that the party who provides the alternative solution will implement the solution before the Generation Resource or SCU with the Attachment Y Notice is permitted to Retire or Suspend. The executed contractual arrangements must provide a binding arrangement that obligates the Market Participant who provides the alternative solution to complete any required infrastructure changes that are needed to avoid the reliability issues that would otherwise be addressed by transmission upgrades. While the contractual arrangements will vary based on the particular solution, the terms of the contractual arrangements must further obligate the party who provides the alternative solution to implement actions when required by the Transmission Provider to provide

necessary relief. A Generator alternative may be a new Generator, an existing Generator that is made available after the Attachment Y Reliability Study is completed, or an increase to existing Generator capacity that has an executed Generator Interconnection Agreement pursuant to Attachment X for a Commercial Operation Date that is prior to the commencement of the change of status date of the Generation Resource or SCU that has submitted an Attachment Y Notice and must be registered as a Generation Resource that is obligated to offer into the market and respond to instructions from the Transmission Provider. Contractual commitments associated with demand-side resource alternative solutions shall require demonstration to the Transmission Provider of an executed contract between LSE or ARC and Energy Consumers as well as necessary procedures and protocols for responding to Transmission Provider instructions. Such demand-side contracts must be in place by the time that the SSR Agreement alternative solution would otherwise need to be committed in order to ensure a timely solution to the identified planning need, and must be of a sufficient duration such that a reliable alternative solution can be assured. In assessing applicability for SSR status, the Transmission Provider will not require continued operation when the continued operation of a portion or all of Generation Resources or SCUs would be contrary to applicable law, regulations, or court or agency orders (such as a settlement with an environmental agency or a consent decree approved by a court). In performing the Attachment Y Reliability Study and the Attachment Y Alternatives Study to an SSR Agreement, the Transmission Provider shall collaborate with the affected Transmission Owners and NERC-registered Transmission Planners, and if appropriate, may consult with a retained consultant. The Transmission Provider will appropriately identify any Confidential Information regarding a decision to Suspend before the Transmission Provider transfers such

information to any entity. An entity that receives Confidential Information must agree in writing to maintain such confidentiality, to comply with any confidentiality obligations owed to Transmission Provider under the Tariff or pursuant to a related non-disclosure agreement, and to comply with applicable Standards of Conduct found in 18 C.F.R. § 358. The owner of the Generation Resource or SCU subject to review under this section shall make good faith efforts to minimize the costs to be incurred by seeking any available waivers or exemptions from environmental or other regulatory requirements that would necessitate improvements to the potential SSR Unit. The Transmission Provider will reasonably assist the owner of a potential SSR Unit in working with regulatory agencies to obtain environmental or other waivers or exemptions to the extent necessary to maintain the reliability of the Transmission System. For purposes of determining whether a Generation Resource or SCU qualifies as an SSR Unit, the Transmission Provider will process multiple Attachment Y Notices in the order in which the Attachment Y Notices are received. If a subsequent Attachment Y Notice is received before a determination is made for a Generation Resource or SCU that is the subject of a prior Attachment Y Notice, the Generation Resource or SCU that is the subject of a prior Attachment Y Notice will not be the subject of an SSR Agreement to avoid reliability issues caused by the subsequently noticed suspension of another Generation Resource or SCU.

The filing of a SSR Agreement with FERC shall be accompanied by a corresponding report on the Attachment Y Reliability Study and the Attachment Y Alternatives Study that details the methodologies used, study assumptions, Transmission Owner planning criteria used (including when the criteria became effective and the approving regulatory body, if any), analysis results, an evaluation of alternatives and the conclusion of the study (including a short

explanation of the proposed solution to any reliability issue identified and estimated timetables for implementing the preferred solution). An affirmation that the results, in whole or in part, from a previously filed report remain applicable may substitute for filing an entirely new report on the Attachment Y Reliability Study and the Attachment Y Alternatives Study.

**d. Modification or Rescission of an Attachment Y Notice.**

**(i) Rescission of an Attachment Y Notice Prior to the Transmission Provider's Reliability Study Response.**

The Transmission Provider shall notify the owner prior to publicizing the Attachment Y Notice and Attachment Y Reliability Study results that the Attachment Y Reliability Study is complete. However, the Transmission Provider shall not provide any information related to the Attachment Y Reliability Study results to the owner at that time. The owner may rescind its Attachment Y Notice by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention, not more than fifteen (15) Business Days after receiving notice from the Transmission Provider that the Attachment Y Reliability Study is complete. In the event of such rescission, the confidentiality of the Attachment Y Notice shall be preserved.

**(ii) Modification or Rescission of an Attachment Y Notice After the Owner of Generation Resource or SCU Receives the Results of Attachment Y Reliability Study, but Prior to Commencing Suspension, Retirement, or an SSR Agreement.**

**(1)** An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the Transmission Provider has determined that the Generation Resource or SCU is not necessary for the reliability of the

Transmission System, may rescind its decision to Suspend any time prior to the end of the period for rescission following the effective date or may modify the start of the suspension any time prior to the original effective date by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention. If the revised date for suspension is prior to the original date specified in the Attachment Y Notice, a new Attachment Y Notice shall be submitted to the Transmission Provider at least four full Quarterly Study Periods prior to the effective date of suspension.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is not necessary for the reliability of the Transmission System, may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice. After the owner has waived the right to both rescind and modify the Attachment Y Notice, the requested status of the Generation Resource will change to Retire, and the interconnection service will be terminated in accordance with Section 38.2.7.k. The Attachment Y Notice will no longer be treated as Confidential Information once the owner has elected to waive its right to both rescind and modify the Attachment Y Notice and committed to retirement of the Generation Resource or SCU.

(2) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the Transmission Provider has determined that the Generation Resource or SCU is required as an SSR Unit may rescind its decision to Retire or Suspend or modify the date of suspension at any time while designated as

an SSR Unit by submitting an amended Attachment Y Notice specifying the modified effective date or stating its decision to rescind.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is required as an SSR Unit may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice for the initial rescission period of the Attachment Y Notice. The owner that provides such notification will retain rescission rights (*i.e.* those additionally acquired by virtue of operating as an SSR Unit) only while designated as an SSR Unit after which time the Generation Resource or SCU will have a Retire status and the interconnection service will be terminated in accordance with Section 38.2.7.k.

**(iii) Modification or Rescission of an Attachment Y Notice After Commencing a Suspension, Retirement, or an SSR Agreement.**

**(1)** An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the resource has not been designated as an SSR Unit or is not continuing to operate pursuant to an SSR Agreement, may rescind its decision to Suspend by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention to rescind any time during the period for rescission following the effective date.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is not necessary for the reliability of the Transmission System, may elect to convert the Attachment Y Notice to

retirement by notifying the Transmission Provider of its intent to waive the right to rescind and modify the Attachment Y Notice. After the owner has waived the right to rescind, the Generation Resource will have a Retire status, and the interconnection service will be terminated in accordance with Section 38.2.7.k. The Attachment Y Notice will no longer be treated as Confidential Information once the owner has elected to waive their right to rescind and committed to retirement of the Generation Resource or SCU.

(2) An owner of an SSR Unit may rescind its decision to Suspend or to Retire or modify the effective date prior to the termination date of the SSR Agreement by submitting an amended Attachment Y Notice specifying the modified effective date or stating its intention to rescind. After receiving an amended Attachment Y Notice from an owner of an SSR Unit to rescind or modify its decision to Suspend or to Retire, the Transmission Provider will then exercise the termination provisions of the SSR Agreement.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is required as an SSR Unit may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice for the initial rescission period of the Attachment Y Notice. The owner that provides such notification will retain rescission rights (*i.e.* those additionally acquired by virtue of operating as an SSR Unit) only while designated as an SSR Unit after which time the Generation Resource or SCU will have a Retire status and the interconnection service will be terminated in accordance with Section 38.2.7.k.

**e. Refund of Costs.**

(i) If the owner of a Generation Resource or SCU that notifies the Transmission Provider of a decision to Suspend and for which the Transmission Provider has not determined the Generation Resource or SCU is needed for reliability rescinds an Attachment Y Notice prior to commencing suspension, then such owner shall pay the Transmission Provider all of the costs that the Transmission Provider incurred in conducting an Attachment Y Reliability Study.

(ii) The Market Participant that owns or operates an SSR Unit must refund to the Transmission Provider with interest at the FERC-approved rate, all costs, less depreciation, for repairs and capital expenditures that were needed to continue operation of the Generation Resource or SCU and to meet applicable regulations and other requirements (including environmental) while the Generation Resource or SCU was subject to an SSR Agreement if the owner: (1) rescinds its decision to Suspend or to Retire the unit while it is designated a SSR; (2) rescinds its decision to Suspend following its previous designation as an SSR Unit; or (3) returns a unit to service following its previous designation as an SSR Unit and later retirement of the unit.

(iii) An owner of a Generation Resource or SCU that returns the unit to service upon failure to Retire or Suspend according to an Attachment Y Notice (*i.e.* returns from retirement or rescinds the Attachment Y Notice, including a Generation Resource or SCU that was not a SSR Unit, a former SSR Unit that no longer operates pursuant to an SSR Agreement, or an SSR Unit) will be allocated the total costs of Network Upgrades incurred or financially committed to as of the date of the notification of modification of the decision to Retire or Suspend if all the following apply:

- the rescission obviates the need for such Network Upgrades that were identified by the Transmission Provider in an Attachment Y Reliability Study;
- such Network Upgrades were necessitated solely by the Attachment Y Notice to Suspend; and
- such Network Upgrades were approved by the Transmission Provider's Board of Directors as Attachment FF Appendix A projects.

The total costs will include all pre-construction costs and interest at the FERC-approved rate.

Such an owner will also be allocated the costs of expedited construction of such Network Upgrades that were approved for purposes other than dealing with needs identified in an Attachment Y Reliability Study to the extent that such expedited construction was necessitated by the Attachment Y Notice to Suspend.

In the event that multiple Attachment Y studies identified reliability issues that required the Network Upgrades and the owners of the units subject to the studies return their units to operation upon failure to Retire or Suspend (*i.e.* return from retirement or rescind the Attachment Y Notices, including Generation Resources and/or SCUs that were not SSR Units, former SSR Units that no longer operate pursuant to an SSR Agreement, or SSR Units), the owners will be allocated the total costs of such Network Upgrades incurred or financially committed to as of the date of notification of the last modification of a decision to Retire or Suspend if all the following apply:

- the rescission obviates the need for such Network Upgrades that were identified by the Transmission Provider in the Attachment Y Reliability Study;

- such Network Upgrades were necessitated solely by the Attachment Y Notice to Suspend; and
- such Network Upgrades were approved by the Transmission Provider's Board of Directors as Attachment FF Appendix A projects.

The total costs will include all pre-construction costs and interest at the FERC-approved rate. Such owners will also be allocated the costs of expedited construction of such Network Upgrades that were approved for purposes other than dealing with needs identified in an Attachment Y Reliability Study to the extent that such expedited construction was necessitated by an Attachment Y Notice to Suspend.

Except as provided in this Section, cost responsibility is assigned only for Network Upgrades that are identified to fully alleviate the violations identified in the Attachment Y Reliability Study in connection with a change in a plan to Retire or Suspend a Generation Resource or SCU. Costs of Network Upgrades that have been identified in the MTEP to address Transmission issues other than the issues identified in the Attachment Y Reliability Study of a unit that requests suspension will not be allocated to the owner of that unit if such costs of construction were not expedited as the result of an Attachment Y Notice to Suspend. In accordance with Attachment FF of the Tariff, the estimated costs of such Network Upgrades are included in the MTEP when it is approved by the Board of Directors of the Transmission Provider for inclusion in the MTEP. The Transmission Provider will solicit from the constructing Transmission Owner the actual costs (including the costs of expediting construction, and pre-construction costs, if any) incurred or committed to as of the date of notification for the last modification of a decision to Retire or Suspend. Each owner shall pay its pro rata share of

the incurred or committed Network Upgrade costs, based on the relative Generation Verification Test Capacity of each resource whose operation causes the assignment of Network Upgrade costs to its owner. The Transmission Provider will promptly notify the responsible owner of their share of the total costs once actual costs are determined.

**f. Execution and Filing of SSR Agreement.**

The Transmission Provider shall enter into an SSR Agreement with the Market Participant owning or operating a Generation Resource or SCU that is needed for SSR purposes based on the *pro forma* Attachment Y-1. The SSR Agreement shall state that it incorporates by reference the compensation authorized by the Commission. Resources that are ineligible to continue operating for legal or regulatory reasons, however, shall not be required to enter into an SSR Agreement. If a potential SSR Unit is ineligible or an existing SSR Unit becomes ineligible to continue operation, then the Transmission Provider shall seek to minimize the impact to Load by operating the Transmission System in the same manner as for any Resource that becomes ineligible to continue operation due to Forced Outage.

The Transmission Provider will file an SSR Agreement with the Commission for approval if the Transmission Provider's analysis determines that the Generation Resource or SCU is required for reliability of the Transmission System. All potentially affected parties will receive notification of such Commission filing. SSR service is a contracted service between the Market Participant that owns or operates an SSR Unit and the Transmission Provider and shall be for a term of twelve (12) months, unless the Transmission Provider requires a different term. The Transmission Provider must have available the entire capacity specified in the SSR Agreement of each SSR Unit.

**g. Operation of SSR Unit.**

Once the Transmission Provider has entered into an SSR Agreement with a Generation Resource or SCU, the Transmission Provider shall have the right to dispatch the SSR Unit at any time for reliability of the facilities within the Transmission Provider Region. The Transmission Provider shall make every attempt to minimize the use of an SSR Unit for reliability purposes. The Transmission Provider will commit the SSR Unit when conditions are identified that require the use of the SSR Unit and will make best efforts to minimize the uneconomic commitment of the SSR Unit. The SSR Agreement found in Attachment Y-1 to this Tariff shall provide for equitable compensation to an SSR Unit when it is dispatched by the Transmission Provider.

**h. Scheduling Rules for SSR Units.**

The Transmission Provider shall notify Market Participants with SSR Units as to the time period of Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve, and/or Other Ancillary Services required from each SSR Unit in accordance with Section 39.1.5 for the Day-Ahead Energy and Operating Reserve Markets, Section 40.1 for Reliability Assessment Commitment processes, and Section 40.1.A.3 Look Ahead Commitment processes.

**i. SSR Unit Participation in Markets.**

A Market Participant may offer Energy or Ancillary Services from SSR Units into the Day-Ahead Energy and Operating Reserve Market, RAC, or Real-Time Energy and Operating Reserve Market during times when the Transmission Provider has not requested the Market Participant to run the SSR Unit at full capacity unless this would impair the ability of the SSR

Unit to provide the Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve, or Other Ancillary Services when requested by the Transmission Provider.

Market Participants that own or operate an SSR Unit shall not use the SSR Unit to: (i) participate in Interchange Schedules; (ii) except for plant auxiliary Load obligations under the SSR Agreement, use the SSR Unit as a Self-Scheduled Resource to submit Self-Schedules for Energy and/or Operating Reserve; or (iii) submit Self-Schedules for Other Ancillary Services, if applicable, to the extent that Other Ancillary Services are required by the Transmission Provider under this Section.

**j. SSR Unit Compensation.**

(i) The Market Participant will be compensated for only costs incurred for the extended operation as an SSR Unit that do not exceed the full cost-of-service (including the fixed cost of existing plant). The hourly component of compensation will be provided as stated in this Tariff. For the determination of any additional compensation, the Market Participant shall submit a filing to the Commission under Section 205 of the FPA that states the additional compensation the Market Participant deems appropriate that is associated with the SSR Agreement filed by the Transmission Provider, but the Market Participant shall not separately file an SSR Agreement. The Market Participant shall provide the Transmission Provider and the Independent Market Monitor with a copy of all compensation-related filings regarding a SSR-designated unit.

(ii) Any compensation for the SSR Unit will be reduced by payments for operation of the SSR Unit, according to the provisions in this Tariff. Monthly compensation under Schedule 2 of this Tariff and payments under resource adequacy programs (a percentage of such payments

to a Market Participant whose generating unit designations are not made) shall be identified in the filing for compensation submitted by the Market Participant.

Hourly compensation will be provided for those hours in which the SSR Unit has Actual Energy Injections and the SSR Unit is committed by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market or committed by the Transmission Provider in any of the RAC processes, or in the Look Ahead Commitment (“LAC”) process, including any Reliability Assessment Commitment (“RAC”) process conducted prior to the Day-Ahead Energy and Operating Reserve Market, in which hours the Transmission Provider shall calculate the Market Participants’ Production Cost and Operating Reserve Cost. For the purposes of this calculation, “Production Cost” means the Energy output cost pursuant to Section 39.3.2B Day-Ahead Revenue Sufficiency Guarantee Payments of the Tariff for commitments by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market or the Energy output cost pursuant to Section 40.2.19 Real-Time Sufficiency Guarantee of the Tariff for commitments by the Transmission Provider in any of the RAC processes, or in the LAC process, including any RAC process conducted prior to the Day-Ahead Energy and Operating Reserve Market, of each SSR Unit based upon Start Up, No Load, and Energy Offer cost components that reflect the actual costs of physically operating the SSR Unit(s). “Operating Reserve Cost” mean the actual cost to provide Operating Reserves. All Production Costs and Operating Reserve Costs will be subject to audit by the Transmission Provider, and will be subject to audit and enforcement by the Independent Market Monitor.

Through the Transmission Provider settlement process, the Transmission Provider will compare the “SSR Unit Compensation,” which (for each SSR Unit) is equal to the sum of

Production Cost and Operating Reserve Cost, to the SSR Unit Energy, Operating Reserve Credit, and Short-Term Reserve. The SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit are those charges and credits calculated pursuant to Sections 39.3 Day-Ahead Energy and Operating Reserve Market, 40.3 Real Time Energy and Operating Reserve Market Settlement and 40.7 Determination of Inadvertent Energy of the Tariff, plus any revenues from Schedule 2 associated with the SSR Unit or from Planning Resource designation and any charges assessed through Schedule 17 and Schedule 24. In those hours where the SSR Unit Compensation is greater than the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit for that SSR Unit, the Transmission Provider will make the applicable make-whole payment to Market Participant (such make-whole payment to be equal to the difference between the SSR Unit Compensation and the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit). In those hours where the SSR Unit Compensation is less than the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit, the Transmission Provider will debit from Market Participant (such debit to be equal to the difference between the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit and the SSR Unit Compensation). If the SSR Unit receives revenue pursuant to Sections 39.3 Day-Ahead Energy and Operating Reserve Market and 40.3 Real Time Energy and Operating Reserve Market Settlement of the Tariff in hours other than those described above, the Transmission Provider will debit those revenues from the Market Participant.

(iii) The Market Participant shall file with the Commission for a Monthly SSR Payment for compensation not covered by the hourly compensation stated in the previous subsection. The Market Participant's filing shall state the requested Monthly SSR Payment along

with its sub-components (including amounts for monthly Schedule 2 payments for each SSR Unit) and applicable cost support, including an affidavit executed by an officer of the Market Participant attesting to the accuracy of the submitted cost information. The Market Participant shall provide the Monthly SSR Payment information for each SSR Agreement, including any renewals of an SSR Agreement, and may update the information in a Section 205 filing to revise such Monthly SSR Payment following any material, unforeseen circumstances affecting the SSR Unit that changes the costs incurred by the Market Participant. The Transmission Provider shall pay the Market Participant the Monthly SSR Payment as directed by the Commission, commencing on the effective date established by the Commission.

The filing for the additional compensation should evaluate, at a minimum, the following factors in negotiating compensation for an SSR Unit: (1) operations and maintenance labor expenses directly related to the SSR Unit; (2) administrative expenses directly related to employees at the SSR Unit, including employee expenses environmental fees, safety and operator training, office supplies, communications, and plant inspection/testing expenses; (3) non-labor maintenance expenses, including chemical and materials consumed during maintenance of the SSR Unit and rental expenses for maintenance equipment used to maintain the SSR Unit; (4) taxes, permit and licensing fees, site security expenses, and insurance; (5) carrying charges, including charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operating unit decisions based on Good Utility Practice; (6) corporate expenses, including those incurred for legal services, environmental reporting, and procurement; (7) costs associated with capitalized projects; (8) depreciation, and (9) return on the undepreciated plant costs for the SSR Unit.

**k. Termination of Interconnection Service.**

Except as provided in Attachment X, the Transmission Provider shall file with the Commission to terminate the interconnection service to the Transmission Provider's system held by an owner of a Generation Resource or SCU or Pseudo-tied out Generator, that certifies by submitting an Attachment Y Notice that it plans to Suspend a Generation Resource or SCU or Pseudo-tied out Generator, upon the latter of: (1) the termination of an SSR Agreement; (2) the effective date for which the owner has elected to convert the Attachment Y Notice to retirement by waiving the right to rescind the decision; or (3) the end of the period for rescission for which the owner has not waived the right to rescind. Such termination of interconnection service shall be contained in a filing with the Commission and also posted by the Transmission Provider on its OASIS to the extent that such interconnection service was filed with the Commission, and shall otherwise be terminated by the Transmission Provider by a posting on its OASIS. If the owner rescinds or modifies the Attachment Y Notice in accordance with Section 38.2.7.d, the owner of such resource may retain its interconnection service and continue to operate after the conclusion of an SSR Agreement or the date specified in the Attachment Y Notice.

**l. Allocation of SSR Unit Costs.**

The costs pursuant to the SSR Agreement shall be allocated to the LSE(s) which require(s) the operation of the SSR Unit for reliability purposes.

**m. Annual Review of SSR Unit Status.**

On at least an annual basis, the Transmission Provider will review Generation Resource or SCU characteristics to determine whether the Generation Resource or SCU is qualified to remain as an SSR Unit in coordination with a review of the Transmission Provider's annual

regional transmission expansion plan in accordance with Attachment FF. If an SSR Unit continues to be required for reliability of the Transmission System, then the Transmission Provider will have the unilateral right to negotiate and enter into a subsequent SSR Agreement by providing the Market Participant at least ninety (90) days advance notice prior to the termination date of the existing SSR Agreement and by negotiating and filing a new SSR Agreement at the Commission. If not, the SSR Agreement will expire by its own terms and the Generation Resource or SCU will lose its SSR Unit status and will resume suspension in accordance with the Attachment Y Notice or Retire. Any subsequent SSR Agreement also shall be filed with the Commission.

**n. Time Limitations on Suspension.**

An owner of a Generation Resource or a SCU or a Pseudo-tied out Generator may request suspension pursuant to the provisions of this Section 38.2.7 and remain for a maximum of thirty-six (36) cumulative months during any five (5) year period under any combination of suspended and SSR-designated statuses. An owner of a Generation Resource or a SCU or a Pseudo-tied out Generator that had not exhausted its maximum period may request an additional suspension period by submitting a new Attachment Y Notice four full Quarterly Study Periods prior to the effective date of the extension period, provided that the combined period is not greater than thirty-six (36) months in a five (5) year period. If a Generation Resource or a SCU or a Pseudo-tied out Generator does not return to service at the end of the thirty-six (36) month maximum suspension period, the Transmission Provider will terminate interconnection service of the resource pursuant to Section 38.2.7.

**o. Non-Binding Informational Studies.**

An owner of a Generation Resource or a SCU may complete an Attachment Y-2 to request that the Transmission Provider conduct a study to determine whether it is likely that a portion or all of such Generation Resource of SCU would qualify as an SSR Unit. The Transmission Provider will collaborate with the affected Transmission Owners and NERC-registered Transmission Planners, and if appropriate, will consult with a retained consultant to evaluate whether the facility is required for the reliability of the Transmission System. The Transmission Provider will appropriately identify any Confidential Information regarding a decision to Suspend that the Transmission Provider transfers to any entity. An entity that receives Confidential Information must agree in writing to maintain such confidentiality, or to any confidentiality obligations owed to Transmission Provider under the Tariff or related non-disclosure agreement, and to comply with applicable Standards of Conduct found in 18 C.F.R. § 358. The owner will not be bound to the change of status indicated in an Attachment Y-2 request. Along with a completed Attachment Y-2, such owner shall submit a study deposit of \$70,000 to the Transmission Provider for the reasonable costs and expenses of such study. The Transmission Provider shall invoice such owner for all costs and expenses incurred in addition to the deposit amount, or shall refund any unused portion of such deposit upon completion of the study.

The Transmission Provider will process multiple Attachment Y-2 requests in the order in which the Attachment Y-2 requests are received. The Transmission Provider shall use reasonable efforts to submit the results of such study to the owner upon its completion within 150 days of receipt of the deposit and completed Attachment Y-2, unless an alternative period is mutually agreed to. The Transmission Provider shall treat Attachment Y-2 as Confidential

Information. If an owner rescinds an Attachment Y-2 study request, then such owner shall not receive the results of the study and the owner shall pay the Transmission Provider all of the costs incurred in conducting the study up until the date of such rescission.

Once a response is provided by the Transmission Provider to the owner, the Transmission Provider shall promptly notify the Independent Market Monitor of any Resource that may qualify as an SSR Unit. The results of such study will provide the owner with the outcome if the owner elects to submit an Attachment Y Notice to request SSR status in the future and does so in accordance with Section 38.2.7.p.

The Transmission Provider shall maintain regional power flow models pursuant to Section I.C of Attachment FF, for use by the owner of a Generation Resource or a SCU choosing to conduct a study.

**p. Submission of Attachment Y Notice Following Non-Binding Reliability Studies Under Y-2.**

The Attachment Y Notice following a non-binding Y-2 request must be submitted at least four full Quarterly Study Periods prior to the date of the planned change of status. The Transmission Provider shall conduct the subsequent Attachment Y process consistent with timeline and milestones in Section 38.2.7.