# POTENTIAL NUCLEAR POWER PLANT CLOSINGS IN ILLINOIS

## Impacts and Market-Based Solutions

**January 5, 2015**

**Response to the Illinois General Assembly**

**Concerning House Resolution 1146**


Prepared by:

ILLINOIS COMMERCE COMMISSION

ILLINOIS POWER AGENCY

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

ILLINOIS DEPARTMENT OF COMMERCE AND ECONOMIC OPPORTUNITY

# House Resolution 1146

***RESOLVED, That we urge the Illinois Commerce Commission to prepare a report examining the State's and grid operators' ability to expand transmissions to allow Illinois to transport clean electricity to other parts of the nation, as well as any legislative impediments, and the impact on residential, commercial, and industrial electric rates from the premature closure of Illinois' nuclear power plants; and be it further***

***RESOLVED, That we urge the Illinois Power Agency to prepare a report showing how the premature closure of existing nuclear power plants in Illinois will affect reliability and capacity for the Midwest region; and be it further***

***RESOLVED, That we urge the Illinois Environmental Protection Agency to prepare a report showing how the premature closure of existing nuclear power plants in Illinois will affect the societal cost of increased GHG emissions based upon the EPA's published societal cost of GHG; and be it further***

***RESOLVED, That we urge the Department of Commerce and Economic Opportunity to prepare a report showing how the premature closure of existing nuclear power plants in Illinois will affect jobs and the economic climate in the affected areas; and be it further***

***RESOLVED, That we urge the findings in those reports to include potential market-based solutions that will ensure that the premature closure of these nuclear power plants does not occur and that the dire consequences to the economy, jobs, and the environment are averted[.]***

# PREFACE

Illinois House Resolution 1146 adopted on May 29, 2014 requests the Illinois Commerce Commission, the Illinois Power Agency, the Illinois Environmental Protection Agency and the Illinois Department of Commerce and Economic Opportunity (collectively, "the Agencies") to prepare reports addressing issues related to the premature closure of nuclear power plants.

Developed on the heels of public statements made by Exelon corporation that it would consider closing select non-profitable nuclear plants in Illinois, HR 1146 urges the Agencies to focus on identifying potential impacts that could result from the premature closure of nuclear facilities related to specific attributes (rates, transmission, reliability, environmental, economic) for which the Agencies have subject matter expertise. HR 1146 further urges the Agencies to include market-based solutions to ensure that premature closures do not occur. Those reports are included herein with each Agency analyzing the following:

- The Illinois Commerce Commission ("ICC" or "Commission") examined the ability of the State and grid operators to expand transmission resources that might allow increased sales of electricity generated from low or zero carbon emitting facilities located within Illinois as well as any legislative impediments related thereto (Chapter 1). The Commission also studied the impact of nuclear plant closures upon customers' rates. Four entities provided analyses to the ICC addressing the effects on generation capacity and customer prices. Reports from Regional Transmission Operators PJM and MISO, the Illinois Institute of Technology and the PJM market monitor, Monitoring Analytics, are attached hereto. The ICC's report summarizes those parties' analyses.
- The Illinois Power Agency ("IPA" or "Agency") examined how nuclear plant closures would affect reliability and the adequacy of generating capacity in the Midwest (Chapter 2). As modeling reliability impacts can be technically sophisticated and intricate, the Agency was assisted by its procurement planning consultant, PA Consulting, and PA's subcontractor, the Energy Consulting Department of General Electric International ("GE"). GE used the Multi-Area Reliability Simulation ("GE-MARS") model, a computer tool that is widely used within the industry to estimate resource adequacy metrics, to simulate reliability and capacity impacts. This reliability simulation was applied to the 2018-2019 delivery year, the first year for which PJM capacity obligations have not been determined, with four distinct scenarios or "cases" – base case, nuclear plant retirement, polar vortex (w/ nuclear retirements), and high load/high retirement (w/ nuclear retirements) – modeled for reliability impacts. Those impacts are demonstrated and explained in the IPA's report.
- The Illinois Environmental Protection Agency ("IEPA") examined how nuclear plant closures would affect the level and societal cost of greenhouse gas emissions (Chapter 3). The societal cost of increased greenhouse gas emissions refers to an economic estimate of the damages on physical and economic systems from climate change impacts caused by carbon dioxide emissions, the main greenhouse gas. The cost estimates are based on United States Environmental Protection Agency ("USEPA") published social cost of carbon values. The cost range of damages due to increased carbon dioxide emissions is based on three nuclear plant retirement scenarios, which vary in the number of plants that would retire and the mix of electricity generation that would replace the lost capacity.

The amount of climate-related damage due to increased emissions from nuclear plant retirements will ultimately depend upon the timing and actual amount of nuclear generation that is closed, along with the carbon intensity of the mix of generation that replaces the lost nuclear capacity. The IEPA's report explains these impacts.

- The Illinois Department of Commerce and Economic Opportunity ("DCEO" or "Department") examined the impact of nuclear plant closures on the job market and the economic climate in the affected areas (Chapter 4). The Department assembled a team of internal and external experts to conduct the assigned economic impact analysis. The project team included academics from Northern Illinois University and Illinois State University, and staff from the Department's Office of Coal Development and Bureau of Energy and Recycling. Economists from Northern Illinois University Center for Governmental Studies and Illinois State University Center for Renewable Energy were tasked to assess the primary and secondary economic impacts of the early retirements of the three targeted Exelon Nuclear assets. Primary economic impact was evaluated in the areas of Employment, Labor Income, and Value-Added economic activity. Secondary economic impact was evaluated in the area of electricity price impact resulting from the loss electricity generation outputs within the state. The project team utilized inputs from a variety of sources in conjunction with a selection of modeling tools to project the economic impact of the early retirement scenarios. This analysis is presented in the Department's report.

Each Agency developed its analysis independently using resources and tools unique to its task. All modeling assumed that the "at-risk" nuclear plants subject to premature closure were the facilities located in Byron, Clinton and the Quad Cities identified as unprofitable by Exelon in the above mentioned public statements. Additionally, HR 1146 directed that these analyses "include potential market-based solutions" to guard against premature closure of at-risk nuclear plants and associated consequences. The final section of this document (Chapter 5) addresses a variety of potential market-based solutions available for adoption by the State of Illinois.[1] Broadly, those solutions include:

- Reliance purely on the market and external initiatives to make corrections
- Establishment of a Cap and Trade Program
- Imposition of a Carbon Tax
- Adoption of a Low Carbon Portfolio Standard
- Adoption of a Sustainable Power Planning Standard

With the exception of simply relying on the market and external initiatives to make corrections, each of the other broad options contains several different methods to achieve the goals. Chapter 5 identifies issues and types of programs within each category.

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[1] While these solutions are presented jointly and reflect the range of solutions considered by the Agencies, the specifics of each solution are intended to be starting points for further discussion and may not represent the specific policy recommendation of any given Agency.

# INTRODUCTION

The first Legislative declaration and finding in the Illinois Power Agency Act provides a clear and succinct summary of Illinois's energy policy:

> *The health, welfare, and prosperity of all Illinois citizens require the provision of adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest cost over time, taking into account any benefits of price stability.*[2]

It is within this context that the Illinois Power Agency, the Illinois Commerce Commission, the Illinois Environmental Protection Agency and the Illinois Department of Commerce and Economic Opportunity set out the following report, conducted the analyses and identified the solutions contained within this document.

## AGENCY ANALYSIS

It cannot be overstated that the results of the specific Agency analyses, as well as the analysis of any of the potential solutions, rely on assumptions. Modeling of rate, reliability, environmental and economic impacts in the highly complex energy sector require first making predictions as to what future scenarios will look like amid a myriad of interrelated, moving parts. The assumptions made about each of these and a host of other questions will impact every conclusion and issue under consideration:

- Which nuclear facilities are at risk?
- Would their generation need to be replaced?
- If so, with what?

Many other external factors influence the decisions made with respect to the nuclear plants such as:

- Regional markets and their rules
- USEPA climate regulations and other guidelines
- Commodity prices (such as for natural gas)
- The number of coal plant retirements
- Investment decisions made by both private investors in generation and transmission assets as well as decisions by regulators in other states
- Technology improvements that change how energy is produced, stored or delivered
- Economic factors that increase or decrease end-use demand for electricity

[2] 20 ILCS 3855/1-5(1)

All of these factors affect the discussion of the impact of nuclear power generation in Illinois and each may experience large shifts or disruptions in the coming years. Given the complexity of applying these variables across four distinct forward-looking Agency analyses, the Agencies believe that results from modeling and analyses cannot be fairly segregated from the assumptions, caveats, and explanations which accompany them. Guided by this logic, the Agencies' have chosen not to provide an independent executive summary to this report, and strongly believe that impacts measured through modeling and analyses must be understood in the context of and with the caveats given in their presentation herein.

## Illinois Energy Outlook

Energy markets are potentially one of the most complex and most important sectors in the global economy. This interaction is further complicated in restructured states like Illinois where planning and control of electricity generation and transmission has been governed by competitive markets and customers may choose their electric supplier. Assessing the impact on electricity prices and reliability of changes in generation supply presents a uniquely challenging exercise wherein results will vary tremendously based on small changes in one assumption out of hundreds. As a result, energy forecasts are seldom reliable and often not critically performed much beyond a short-term time window.

Likewise, fossil fuel prices are highly volatile and unpredictable. The global economic recession has depressed energy prices in the near term; however, the US and Illinois recovery will push prices upward. Natural gas prices, which in large part drive electricity prices, are currently low as a result of the recession, increased exploration, and new recovery techniques such as hydraulic fracturing.

Illinois energy policy may not be able to address potential plant closures and new environmental rules without legislative action. For example, the Illinois Renewable Portfolio standard is not functioning as well as intended. The restructured market further impedes certain solutions such as traditional in-state preferences. Energy efficiency programs are constrained by rate impact caps that overvalue short term costs at the expense of long term benefits. Energy storage is an emerging technology not currently addressed by policies in Illinois. Current levels of Illinois worker retraining programs will not be able to absorb shifts in generation trends and minority participation in the green economy is not keeping pace with expansion of this sector. Finally, Illinois does not have a meaningful market mechanism to address carbon reductions.

## Illinois Energy Context

Illinois is at the forefront of the national energy industry. The state has an abundant supply of electric capacity (45,000 megawatts) and produces 190 billion kilowatts per year at over 60 facilities. Illinois has a diverse fuel mix including generation from coal, natural gas, wind, solar and is dominated by nuclear power. The state is a net exporter of electricity and a hub for electric transmission lines as well as oil and gas pipelines.

Illinois is the nation's leader in the production of nuclear power, generating approximately 90 billion kilowatt hours with 11 nuclear units. Illinois has six nuclear power stations, containing 11 reactor units, which are licensed by the Nuclear Regulatory Commission ("NRC") to operate for another 7 to 18 years. Some of these units can be relicensed for an additional 20 years. By industry standards, these plants operate at very high capacity factors (average output divided by peak capacity). The Illinois nuclear power stations account for about a quarter of the generating capacity within the State. In recent years, approximately half of the electricity sold by utilities and alternative retail electric suppliers in Illinois has been generated by nuclear facilities.

Forty-three percent of Illinois' electricity is generated by coal-fired facilities located throughout the state. Coal underlies 37,000 square miles of Illinois – about 65% of the State's surface. Recoverable coal reserves account for almost 1/8th of total US reserves and account for more BTUs than the oil reserves of Saudi Arabia and Kuwait.

In 1997, Illinois became one of only a handful of states to restructure its electric markets. Electric distribution was maintained as a fully regulated utility service. Transmission planning and control was granted to independent regional transmission operators[3] to protect competitively neutral markets. Generation was spun off to become a competitive market, which created a path towards retail competition for electric supply service. The success of retail competition has helped to lower prices and provide market-based efficiencies. As a result, Illinois electricity prices are generally lower than in neighboring states that did not restructure. However, the traditional utility regulatory paradigm in which utility investors are granted a just and reasonable rate of return on the value of their assets no longer applies to generation resources in Illinois.

The Illinois General Assembly responded to increases in prices for residential customers by passing the next watershed changes to Illinois energy policy in 2007. Chief among those was to create the Illinois Power Agency – a new State Agency tasked with purchasing electricity for customers that have not selected an alternative retail electricity supplier, i.e., customers who remain with the default utilities, ComEd and Ameren. The 2007 Act also laid the foundation for a modern Illinois energy economy through the adoption of a Renewable Portfolio Standard and Electric Efficiency Portfolio Standard. These policies are among the strongest in the country.

Since then, Illinois has further expanded its energy framework. The General Assembly broadened the energy efficiency programs to include natural gas through the Natural Gas Energy Efficiency Portfolio Standard. The Renewable Portfolio Standard was extended to alternative retail electric suppliers and carve-outs were added for photovoltaics and distributed generation. Wind Farms were designated as a High Impact Business for state enterprise zone benefits. Property Tax Valuation for wind farms was standardized. Energy efficiency programs were expanded to include natural gas and geothermal as well as lengthening project completion times to three years to allow for larger projects and increased flexibility to achieve deeper savings. The goal of the Energy Infrastructure Modernization Act was to build a 21st Century electric grid, providing consumers with advanced tools to manage their electric usage, and the hardening of the local distribution grid.

FutureGen was approved and is scheduled to come on line in 2017. This project will involve retrofitting an existing coal plant with state-of-the-art carbon capture and sequestration technology in order to generate low carbon energy using Illinois coal. The project will create 1,000 construction jobs, 175 permanent jobs, sequester 1.1 million tons of carbon dioxide per

[3] Illinois is in two regional transmission organizations, or RTOs: PJM and MISO.

year and demonstrate a cleaner coal technology that Illinois can export to the nation and the world.

The Illinois alternative energy sector has grown substantially since 2007. Due to the past successes of the Illinois Renewable Standard, Illinois now ranks 4th for total MW of installed wind capacity, and the Illinois solar industry continues to expand with the support of Public Act 98-0672, enacted earlier this year. This growth has led to a dramatic increase in manufacturing jobs at renewable component manufacturers across Illinois from Peoria to Cicero, Clinton, Rockford, and Chicago. American Council for an Energy Efficient Economy (ACEEE) rates Illinois' energy efficiency programs in the top 20. Over 100,000 people in Illinois are now employed by the green economy in Illinois.

## ILLINOIS ENERGY POLICY

The Illinois energy strategy builds upon several existing statutes, plans, and executive orders that establish a robust policy foundation.

The **Electric Service Customer Choice And Rate Relief Law Of 1997** establishes that:

- "With the advent of increasing competition in this industry, the State has a continued interest in assuring that the safety, reliability, and affordability of electrical power is not sacrificed to competitive pressures, and to that end, intends to implement safeguards to assure that the industry continues to operate the electrical system in a manner that will serve the public's interest."
- "A competitive wholesale and retail market must benefit all Illinois citizens. The Illinois Commerce Commission should act to promote the development of an effectively competitive electricity market that operates efficiently and is equitable to all consumers. Consumer protections must be in place to ensure that all customers continue to receive safe, reliable, affordable, and environmentally safe electric service."
- "All consumers must benefit in an equitable and timely fashion from the lower costs for electricity that result from retail and wholesale competition and receive sufficient information to make informed choices among suppliers and services."

The **Illinois Power Agency Act** finds that "The health, welfare, and prosperity of all Illinois citizens require the provision of adequate, reliable, affordable, efficient, and environmentally sustainable electric service…" Towards that goal, the statute creates a Renewable Portfolio Standard requiring renewable sources that began with 2% of electricity supply in 2008 and is scheduled to rise to 25% in 2025.

The **Illinois Public Utilities Act** includes Energy Efficiency Portfolio Standards, which require electricity savings of 0.2% in 2008 rising to 2% annually by 2015 and natural gas savings of .2% in 2012 increasing to an additional 1.5% in 2019 and each year thereafter.

The **Energy Policy and Planning Act** sets the following policy for Illinois: "To become energy self-reliant to the greatest extent possible, primarily by utilization of the energy resources available within the border of this State, and by the increased conservation of energy."

The **Government Buildings Energy Cost Reduction Act** declares it to be the policy of the State of Illinois "to establish interagency and intergovernmental programs for the purpose of deploying cost-effective energy conservation measures and technologies to minimize energy consumption and costs." The **Agency Energy Efficiency Act of 2008** further mandates the State to reduce energy use in State facilities by 10% within 10 years.

The **Energy Conservation Act, Energy Conservation and Coal Development Act, Renewable Energy, Energy Efficiency and Coal Resources Development Act** and others further develop these policies.

The **Illinois Climate Change Advisory Group** established the following statewide greenhouse gas reduction goals for Illinois:

- Reduce emissions to 1990 levels by 2020
- Reduce emissions to 60% below 1990 levels by 2050.

This reduction is in line with the nationwide reduction of 30 percent below 2005 levels by 2030 articulated in USEPA's recently released Clean Power Plan. The Advisory Group also recommended a set of 24 strategies to achieve the first of these goals, through building energy efficiency, renewable energy, and transportation energy efficiency programs and policies.

### THE WAY FORWARD

The right energy policy has the potential to minimize cost increases, guarantee reliability, improve the environment, create and retain jobs, and grow the Illinois economy. If Illinois is to move forward with a robust response, the full impact of such a policy would have to be fully explored. The Agencies set forth the analyses and the market-based solutions in this report as another useful reference point in gaining that understanding.

**Potential Nuclear Power Plant Closings in Illinois**

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Electric Transmission Expansion and Potential Rate Impacts

CHAPTER 1. ILLINOIS COMMERCE COMMISSION'S RESPONSE

***RESOLVED, That we urge the Illinois Commerce Commission to prepare a report examining the State's and grid operators' ability to expand transmissions to allow Illinois to transport clean electricity to other parts of the nation, as well as any legislative impediments, and the impact on residential, commercial, and industrial electric rates from the premature closure of Illinois' nuclear power plants;***

# ILLINOIS COMMERCE COMMISSION'S RESPONSE

## Electric Transmission Expansion

### Introduction

The devices that generate and consume most of the electricity in this country are interconnected through vast networks of cables, transformers, and other transmission and distribution facilities, all of which are commonly referred to as "the grid." The backbone of the grid is comprised of its high-voltage sections and is referred to as the "bulk" power system. Illinois' transmission system conducts electricity at voltages ranging from 69,000 Volts (69 kV) to 765,000 Volts (765 kV).

This section describes by whom and how the transmission system is owned, operated, managed, and regulated. It also describes how the system responds to actual and projected changes in electricity supply and demand. With this foundation, the report addresses the Resolution's directive to examine the ability of the State and grid operators to expand transmission resources that might allow increased sales of cleanly-generated (low or zero carbon emitting for purposes of this analysis) electricity from generating facilities located within Illinois.

### Ownership of the Electric Transmission System

The electric transmission system in the United States is owned by various private and public electric entities. In Illinois, for example, this includes:

- Ameren Illinois Company, which owns 4,548 miles of transmission lines.[4]
- Ameren Transmission Company of Illinois (ATXI), which owns 29 miles of transmission lines, and whose current plan includes construction of an additional 400 miles known as the Illinois Rivers Project (beginning in Missouri and ending in Indiana).[5]
- Commonwealth Edison Company, which owns 5,024 miles of transmission lines[6], and whose current plan includes construction of the nearly 70-mile Grand Prairie Gateway 345 kV high voltage transmission line through Ogle, DeKalb, Kane and DuPage counties.
- MidAmerican Energy Company, which owns 244 miles of transmission lines in Illinois.[7]
- Several municipal and cooperative utilities.

In addition, the following companies are planning transmission projects within Illinois:

- Exelon and AEP Transmission Holding Company, LLC (AEP) are working collaboratively to develop a high-voltage transmission project from the western Ohio

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[4] Ameren Corporation, SEC Form 10-K for the fiscal year ending December 31, 2013, filed 3/3/2014, p. 23.

[5] Ameren Corporation, SEC Form 10-K for the fiscal year ending December 31, 2013, filed 3/3/2014, p. 23.

[6] Source: Exelon Corporation, SEC Form 10-K for the fiscal year ending December 31, 2013, filed 2/14/2014, p. 68.

[7] ICC Docket 14-0066, Order, p. 3.

border through Indiana to the northern portion of Illinois. Referred to as the Reliability Interregional Transmission Extension (RITE) Line project, the project purportedly will strengthen the high-voltage transmission system and improve overall system reliability.[8]

- Clean Line Energy Partners plans to build two high-voltage direct current transmission lines into or across Illinois – both originating in wind-rich regions of the Midwest. On November 25, 2014, the ICC granted the company's request for authority to construct, operate and maintain the Rock Island Line. The line is to originate at a converter station in O'Brien County, Iowa, and enter Illinois south of Cordova. From there, the line would extend for approximately 121 miles in Illinois to the Collins Substation in Grundy County.[9] A second project, the Grain Belt Express, is to originate in Kansas, cross Missouri and Illinois, and terminate in Indiana. [10] The company has begun conducting the Illinois public meetings required by law to precede a filing for ICC approval of the line.

**Regulatory Oversight**

The Federal Energy Regulatory Commission ("the FERC") is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. The FERC's various regulatory responsibilities related to the electric industry include:

- Regulating the transmission and wholesale sales of electricity in interstate commerce;
- Reviewing siting applications for electric transmission projects under very limited circumstances;
- Protecting the reliability of the high voltage interstate transmission system through mandatory reliability standards; and
- Monitoring and investigating energy markets.

The planning and operation of the bulk transmission system within Illinois is largely outside state jurisdiction. For the most part, transmission planning is performed by regional transmission organizations (RTOs, described in detail below) that are subject to the jurisdiction of the FERC and are not regulated by the ICC or any other state agencies. Stakeholders (including the ICC) are permitted to participate in RTO planning in an advisory capacity and to participate in FERC proceedings as interested parties. States retain jurisdiction over transmission siting.

With respect to transmission siting, Illinois law requires transmission project owners to obtain permission from the ICC for each project that will be constructed within or across Illinois borders. This gives the ICC the authority and responsibility to ensure that projects are necessary

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[8] RITELine Illinois, LLC (RITELine Illinois) and RITELine Indiana, LLC (RITELine Indiana) have been formed as project companies to develop and own the project. RITELine Illinois will own the transmission assets located in Illinois and is owned 75% by ComEd and 25% by RITELine Transmission Development Company, LLC (RTD). RITELine Indiana will own the transmission assets located in Indiana and is owned by AEP (75%) and RTD (25%). Exelon Transmission Company, LLC and AEP each own 50% of RTD. Source: Exelon Corporation, SEC Form 10-K for the fiscal year ending December 31, 2013, filed 2/14/2014, p. 88.

[9] ICC Docket 12-0560, Proposed Order, p. 3.

[10] Source: Clean Line Energy Partners web site -- http://www.cleanlineenergy.com/projects

and will promote the public convenience. For example, Section 8-406(b) of the Public Utilities Act states:

> (b) No public utility shall begin the construction of any new plant, equipment, property or facility which is not in substitution of any existing plant, equipment, property or facility or any extension or alteration thereof or in addition thereto, unless and until it shall have obtained from the Commission a certificate that public convenience and necessity require such construction. Whenever after a hearing the Commission determines that any new construction or the transaction of any business by a public utility will promote the public convenience and is necessary thereto, it shall have the power to issue certificates of public convenience and necessity. The Commission shall determine that proposed construction will promote the public convenience and necessity only if the utility demonstrates: (1) that the proposed construction is necessary to provide adequate, reliable, and efficient service to its customers and is the least-cost means of satisfying the service needs of its customers or that the proposed construction will promote the development of an effectively competitive electricity market that operates efficiently, is equitable to all customers, and is the least cost means of satisfying those objectives; (2) that the utility is capable of efficiently managing and supervising the construction process and has taken sufficient action to ensure adequate and efficient construction and supervision thereof; and (3) that the utility is capable of financing the proposed construction without significant adverse financial consequences for the utility or its customers.

**Management and Operation of the Grid: The Regional Transmission Organizations**

In December 1999, the FERC issued Order No. 2000 establishing the framework for the formation of regional transmission organizations ("RTOs"). Order No. 2000 states that the motivation for establishing RTOs was to promote efficiency in wholesale electricity markets, to ensure that electricity consumers pay the lowest price possible for reliable service, and to resolve impediments to fully competitive electricity markets.[11] The FERC set out to achieve these objectives by addressing undue discrimination and market power, as well as economic and engineering issues affecting reliability, operational efficiency, and competition in the electric industry.

RTOs are independent entities that operate the transmission facilities of their members. RTOs:

(1) Manage the bulk power transmission systems within their footprints;

(2) Ensure non-discriminatory access to the transmission grid by customers and suppliers;

(3) Dispatch generation assets to balance supply and demand;

(4) Operate markets for electric energy, capacity, and ancillary services; and

(5) Develop regional transmission expansion plans.

Currently, there are seven distinct RTOs operating in the continental United States (See the map, below). Each of Illinois' major utilities currently participates in one of two RTOs.

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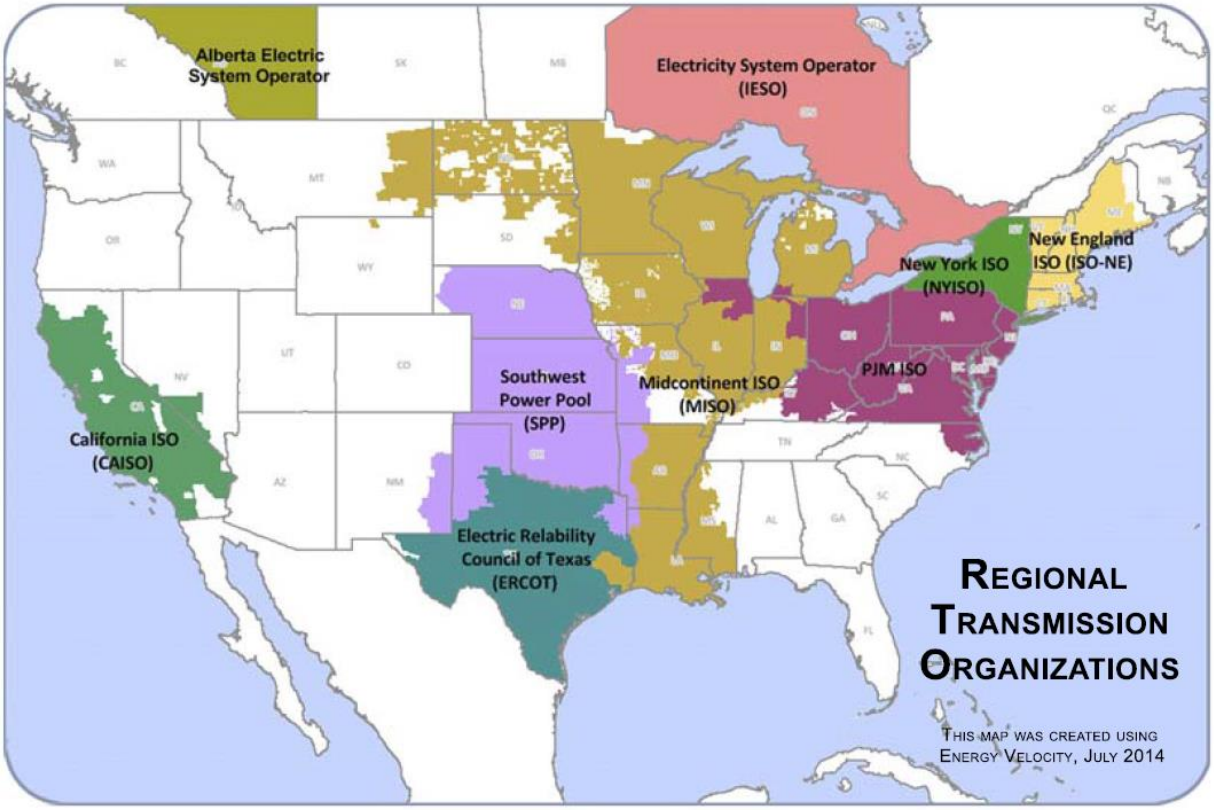
[11] *Regional Transmission Organizations*, 89 FERC ¶ 61,285, (1999) ("Order No. 2000"), at 1 and 115.

Commonwealth Edison is a transmission-owning member of PJM. Ameren Illinois and MidAmerican are transmission-owning members of MISO.[12]




Source: http://www.ferc.gov/industries/electric/indus-act/rto/elec-ovr-rto-map.pdf

PJM was established in 1927, when three eastern utilities formed a power pool.[13] In 2001, the FERC approved PJM as an RTO. In 2004, Commonwealth Edison was integrated into PJM. PJM's footprint covers all, or part of, thirteen states and the District of Columbia, with a population of 61 million people. The majority of PJM's transmission-owning members are located in the Mid-Atlantic region where remote generation sources are typically connected to load centers by high-voltage transmission lines, generally 500 kV and 230 kV.

MISO was established in 1998 as an independent system operator by a group of Midwest utilities.[14] In 2001, the FERC approved MISO as the nation's first RTO. By 2002, the utility companies that ultimately became Ameren Illinois were members of MISO. MidAmerican joined MISO as a transmission-owning member in 2009. MISO's footprint includes all or part of

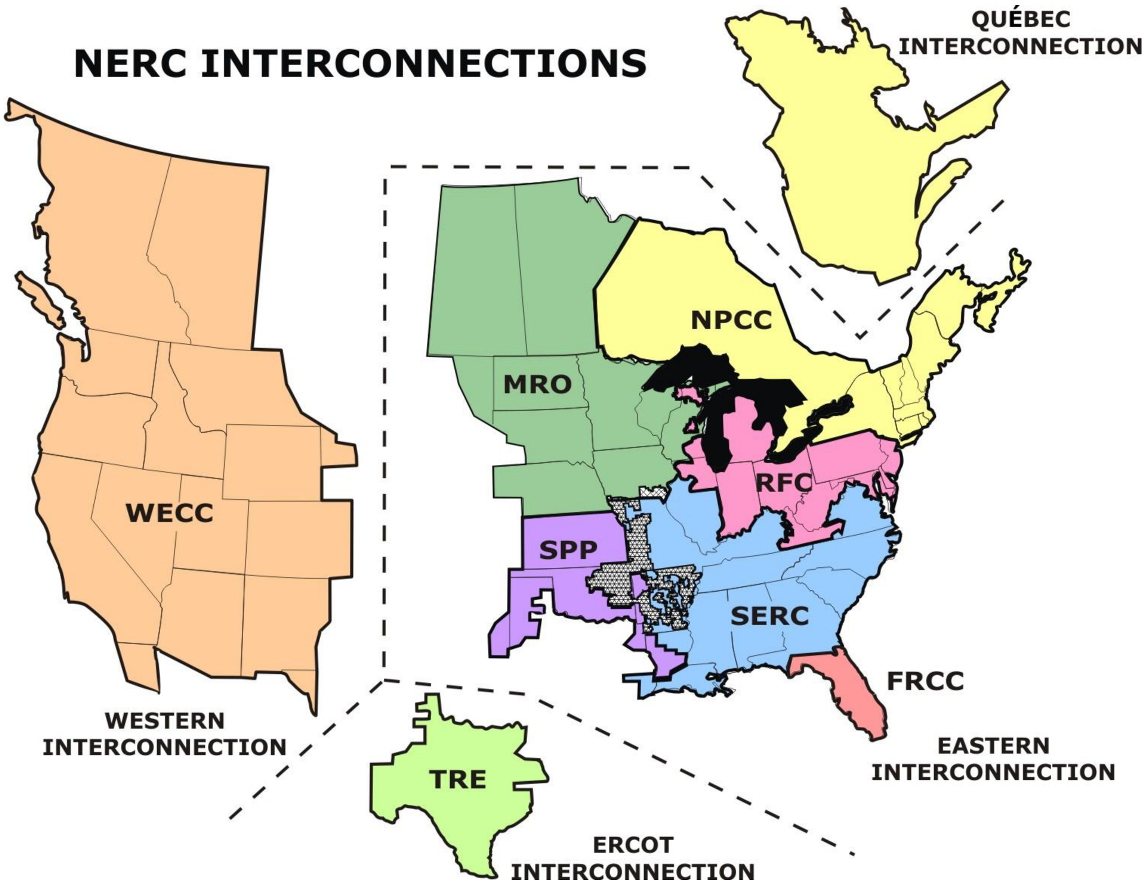
[12] As are Southern Illinois Power Co-op, City Water Light and Power, and Prairie Power.

[13] PJM history is recounted on its webpage. See, for instance: http://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx

[14] MISO's history is recounted on its webpage. See, for instance: https://www.misoenergy.org/AboutUs/History/Pages/History.aspx

fifteen states and one Canadian province, with a combined population of 42 million people.[15] Historically, the majority of generation sources within MISO have been in close proximity to load centers. As such, the high voltage levels for transmission facilities in the MISO region are generally 345 kV or less.

Interconnections exist not only within RTOs, but between RTOs (and other non-RTO entities) as well. The following map shows the approximate geographic boundaries of the four synchronized alternating current electric systems recognized by the North American Electric Reliability Corporation ("NERC"): (1) the "Eastern Interconnection" (within which both MISO and PJM are situated); (2) the "Western Interconnection"; (3) the "ERCOT Interconnection" (Texas); and (4) the "Quebec Interconnection."[16]




With operational authority of the transmission system, the RTO acts as a security coordinator to ensure reliability in real-time operations of the power grid. As security

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[15] The Canadian province of Manitoba is part of MISO's reliability footprint. Manitoba is not part of MISO's market footprint.

[16] The North American Electric Reliability Corporation is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America. NERC develops and enforces reliability standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel.

coordinator, the RTO assumes responsibility for such actions as: (1) performing load-flow and stability studies to anticipate, identify and address security problems; (2) exchanging security information with local and regional entities; (3) monitoring real-time operating characteristics such as the availability of reserves, actual power flows, interchange schedules, system frequency and generation adequacy; and (4) directing actions to maintain reliability, including firm load shedding. However, the separation of ownership from control, represented by operational authority, has its limits. For example, while RTOs perform regional transmission planning within their footprint and have responsibility for ensuring reliability of the power grid, RTOs generally cannot compel member transmission owners to make investments in transmission facilities. Rather, RTOs rely on a variety of market mechanisms to create financial incentives for their transmission owning members to invest in generation or transmission; and many transmission investments needed for reliability are eligible for fixed rates of return set by the FERC.

### Governance of MISO and PJM

RTO decision-making is typically carried out by a Board of Directors that is independent of RTO stakeholders. This independence from stakeholders is critical to minimizing undue influence over the board by market participants. Typically, an RTO board member is prohibited from being a director, officer, or employee of a member, user, or affiliate of a member or user for a specified period of time before or after election to the board. It is not uncommon for RTO board members or their family members to be prohibited from owning certain securities or having other holdings in any company affected by the decisions of the RTO. RTOs are not market participants, so they do not take any financial or physical position in the markets that they operate.

The Board of Directors is supported by numerous committees, sub-committees, task forces, and RTO staff. Through a stakeholder process, the Board is also informed of the views of transmission owners, independent power producers, investor-owned utilities, municipal utilities, electric cooperatives, power marketers, consumer advocates, state regulatory authorities, environmental advocacy groups, and other interested parties. The stakeholder process generally produces recommendations for the Board regarding RTO issues. Finally, while the RTO's Board of Directors makes decisions for the RTO, policies that directly or indirectly affect transmission rates or wholesale power prices require approval by the FERC before being implemented.

RTO membership is voluntary. The RTOs have what is referred to as "operational authority" over the transmission facilities of their transmission-owning members. This means that RTOs do not own the transmission facilities under their control, but rather operate the facilities on behalf of the owners. This authority covers a wide array of grid responsibilities, including switching transmission elements into and out of operation in the transmission system (e.g., transmission lines and transformers), monitoring and controlling real and reactive power flows, monitoring and controlling voltage levels, and scheduling and operating reactive resources. The RTO accomplishes this through direct physical operation by RTO employees or through contractual agreements with other entities (e.g., transmission owners and control area operators).

### Transmission Projects since 2004 in PJM and MISO

The expansion plans of both MISO and PJM have been quite substantial. For example, MISO's 2013 expansion plan included 317 new transmission projects, representing a $1.48

billion investment.[17] Since 2003, MISO has approved over $6.2 billion in transmission expansion projects and has roughly 10,442 miles of new and/or upgraded transmission lines planned through 2022.[18] Similarly, in 2013, PJM approved over 700 individual upgrades to the PJM system totaling $7.1 billion.[19] Since 1999, PJM has approved close to $29 billion in system upgrades. This includes nearly $21 billion of baseline transmission upgrades across PJM and over $8 billion of additional transmission upgrades to enable the interconnection of over 51,000 Megawatts ("MW") of new generating resources.[20] RTO transmission plans are forward-looking documents, so many of the transmission projects contained in PJM and MISO plans have yet to be developed.

Although transmission projects are initially approved by the RTOs, RTOs cannot compel utilities to construct transmission lines. In many states, such as Illinois, that power lies with the state public utility commission. In other states, various state agencies or local courts have the authority to approve transmission line siting. Therefore, including a transmission line in a RTO's transmission expansion plan does not necessarily mean that the line will be built.

**The RTO Transmission Planning Process**

Regional transmission expansion planning by RTOs, such as MISO or PJM, is performed pursuant to several FERC orders, including Order No. 2000 (in 1999), Order No. 890 (in 2007), and Order No. 1000 (in 2011). As already mentioned, FERC Order No. 2000 established the RTO structure. FERC Order No. 890 prohibited undue discrimination and preference in transmission service and required that each RTO perform regional transmission planning that primarily addressed reliability needs and economic opportunities. FERC Order No. 1000 expanded that planning process to include consideration of public policy objectives.

An RTO's responsibility for transmission planning and grid expansion within its region is one of the requirements of an RTO. The FERC's rationale for this requirement is that a centralized planning approach employed by an RTO should help to realize the engineering and economic efficiencies that would not occur if each individual transmission owner made independent decisions about the limitations and expansion of its piece of the interconnected transmission grid. Indeed, PJM currently has 31 transmission owners and almost 63,000 miles of transmission lines. MISO has 48 transmission owners and almost 66,000 miles of transmission lines. In the absence of a single entity performing the transmission planning functions, it is likely that individual transmission investments will work at cross-purposes, increasing costs and possibly even reducing grid reliability.

The development of an RTO's transmission expansion plan is the product of collaboration between the RTO's planning staff, the transmission-owning utilities and interested stakeholders. This RTO-led planning process identifies and supports development of transmission infrastructure that is sufficient to meet local and regional reliability standards, and

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[17] 2013 MISO Transmission Expansion Plan, p. 4. Posted on MISO website: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=168129

[18] *Id*., pp. 17-18.

[19] 2013 PJM Regional Transmission Expansion Plan, Book 1, p. 2. Posted on PJM website: http://www.pjm.com/~/media/documents/reports/2013-rtep/2013-rtep-book-1.ashx

[20] *Id*., pp. 2-3.

to identify projects that provide economic benefits, such as increased market efficiency or facilitate public policy objectives, such as renewable portfolio standards. The interconnection of new generation resources to the transmission grid is also a significant element of the transmission planning process.

Regardless of the project type, a potential transmission project is submitted to the RTO for modeling to evaluate the impact on the regional transmission system and subjected to review through the RTO-led stakeholder groups. Proposed projects are evaluated pursuant to specific metrics in the respective RTO's tariff for each project type. Examples of the criteria that proposed projects must meet include metrics such as total project cost, benefit-cost ratios and reduction in generator production costs. Several specific project types are discussed, below.

**Reliability Projects**

Most transmission projects contained in the RTOs' transmission expansion plans are there to resolve reliability issues. Transmission planners at the RTOs conduct forward-looking studies to determine whether the existing transmission system can reliably serve electric customers in future years based upon projections of load growth and forecasted changes to generation and other resources.

Reliability standards are established by NERC, subject to FERC oversight. There are also regional reliability organizations ("RROs") that are delegated authority by the NERC. ComEd's transmission system is part of the Reliability First Corporation RRO. Ameren Illinois' transmission system is part of the SERC Reliability Corporation RRO. RTO planners determine whether the reliability standards established by NERC, the applicable RROs, and member transmission owners will be met. If such standards are not met, the RTO transmission planning process evaluates how to best resolve the violations and places that project into the plan.

**Market Efficiency (Economic Enhancement) Projects**

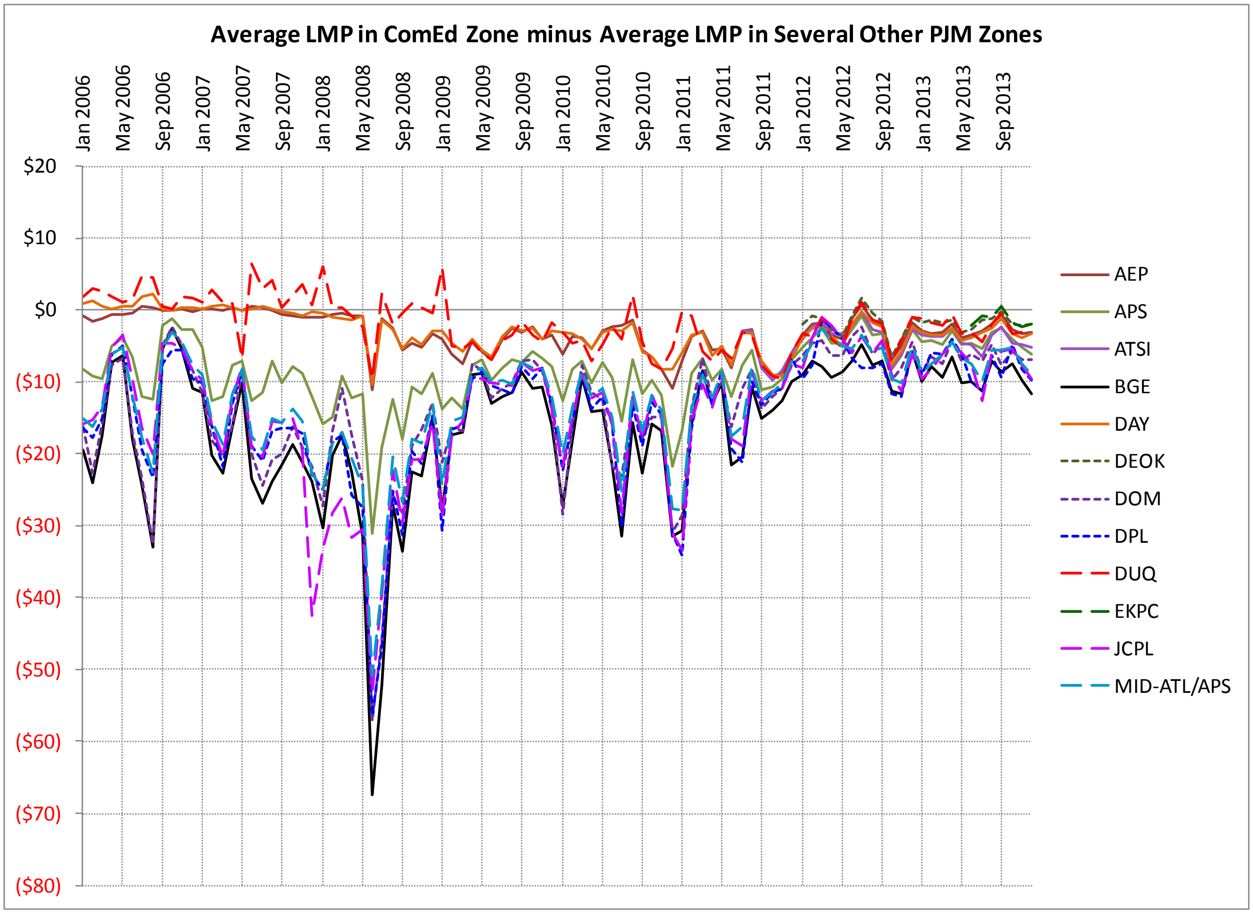
In the case of MISO, a proposed "market efficiency" project must:

- Produce regional economic benefits, as demonstrated through multi-future and multi-year planning;
- Operate at voltages of 345 kV or higher;
- Cost at least $5 million to build, with at least half of the project cost associated with 345 kV or above facilities; and
- Yield a benefit-cost ratio in excess of 1.25.

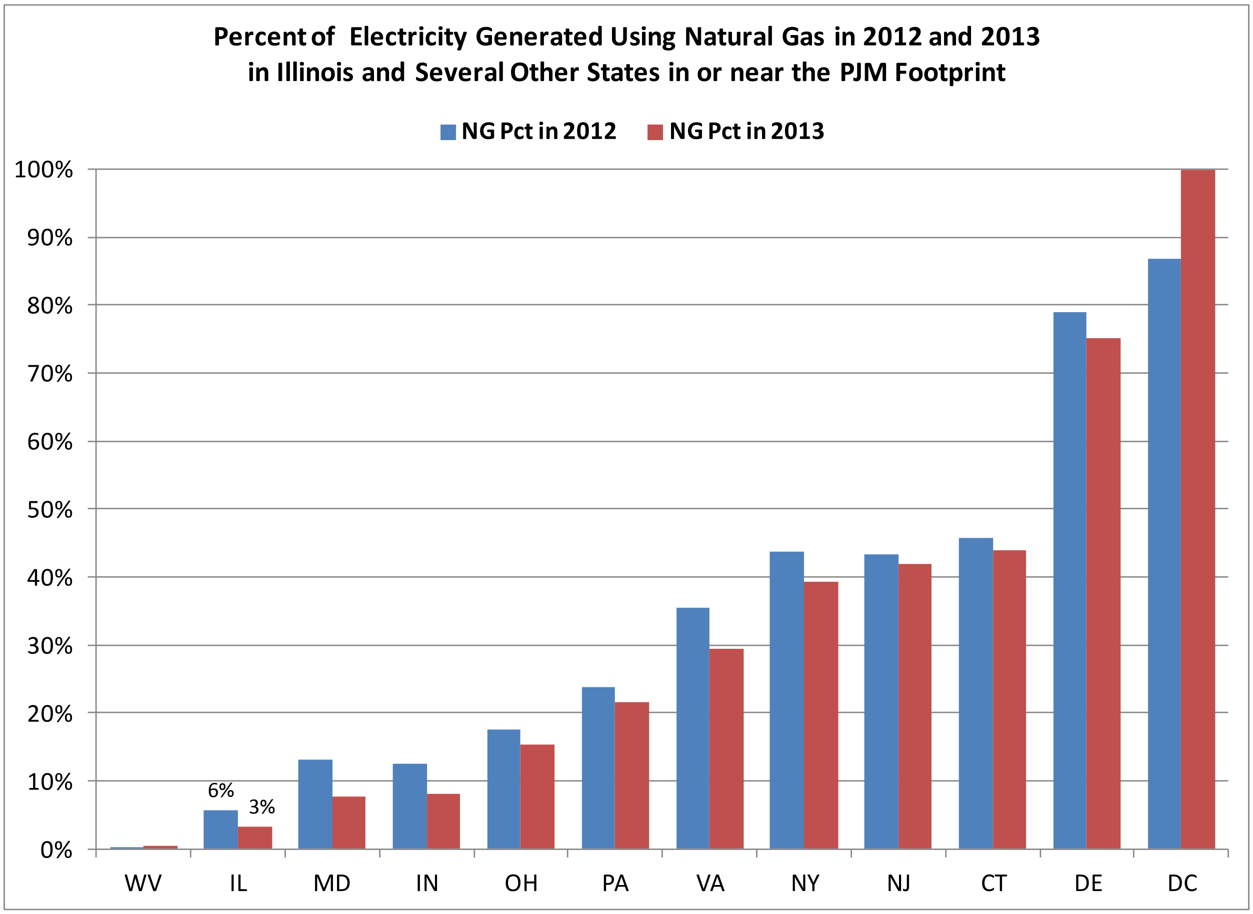
Similarly, in PJM, "economic enhancement" projects are required to have a benefit/cost ratio of at least 1.25 to be included in the PJM transmission expansion plan. PJM calculates the benefit/cost ratio as follows:

Benefit/Cost Ratio = [Present value of the Total Annual Enhancement Benefit for each of the first 15 years of the life of the enhancement or expansion] ÷ [Present value of the Total Enhancement Cost for each of the first 15 years of the life of the enhancement or expansion]

Over the last several years, several economic enhancement projects in northern Illinois have been proposed to PJM. Such projects are not required for reliability reasons. Typically, economic enhancement projects are proposed by transmission developers in response to differences in locational marginal prices ("LMPs"). LMPs are a measure of energy prices and congestion at specific points on the transmission grid. The location-specific nature of LMPs is designed to signal market participants where additional generation or transmission resources are most needed. These proposed economic enhancement projects initially met the benefit/cost ratio criteria for inclusion in PJM transmission expansion plans. However, subsequent analyses demonstrated that the projects no longer passed the 1.25 benefit to cost ratio threshold required by the PJM tariff, apparently because the difference in LMPs between northern Illinois and eastern PJM became insufficient to justify the proposed transmission projects. The narrowing of such geographical price differences is illustrated in the following chart, which shows the Average LMP in the ComEd Zone of PJM minus the Average LMP in several other PJM zones over time, between 2006 and 2013.




There are several reasons why the LMP differential between northern Illinois and the rest of PJM has narrowed. First, developments in the natural gas market have tended to lower LMPs, generally, since natural gas-fueled generating units are often the marginal units dispatched to meet load. However, the impact of natural gas prices has been more pronounced in the eastern portion of PJM, where the utilization of natural gas-fueled generating units is more pronounced than it is in Illinois (See chart below).




Source: U.S. Department of Energy, Energy Information Administration (EIA), Monthly Generation Data by State, Producer Sector and Energy Source; Final 2012

Second, while proposed economic enhancement projects in northern Illinois were rejected, there has been considerable new transmission investment in several locations within PJM, justified on a variety of grounds. Whatever their primary justification, such projects tend to result in the reduction in geographic price differentials.

**Public Policy and Multi-Driver Projects**

Public policy transmission projects include those that support goals such as the expansion of renewable energy. The mechanism for including such transmission projects in PJM's transmission plan is referred to as the state agreement approach.[21] The state agreement approach provides that a state or group of states may propose a transmission project for inclusion in PJM's Regional Transmission Expansion Plan to address state public policy if they adopt a cost allocation mechanism that ensures all costs will be borne within those state(s). So far, no public policy projects pursuant to the state agreement approach have been included in PJM's transmission plan. Typically, public policy projects have been envisioned as facilitating the transmission of renewable energy, but there are no limitations upon states for the type of projects that can be approved under the state agreement approach. For example, if increased access by

[21] Section 1.5.9, Schedule 6, PJM Operating Agreement

Illinois nuclear generation to Eastern PJM markets would lead to desirable public policy outcomes, transmission projects to enhance such access could be pursued as an Illinois public policy under PJM's state agreement. However, in such an event, Commonwealth Edison rate payers would likely bear the entire costs of such transmission projects.

So-called "multi-driver" projects provide another route for pursuing "public policy" objectives through the transmission planning process. PJM and its transmission owners have a proposal before the FERC regarding multi-driver projects. Under the proposal, a planned transmission project intended to address either reliability or market efficiency issues could be expanded or modified to address public policy requirements. These combined projects are called "multi-driver" projects. Proponents of the proposal believe that combining several transmission projects that are justified by separate criteria into one multi-driver project would be more efficient than addressing each need separately. At this time, the FERC has yet to approve PJM's multi-driver proposal.

**Interregional Transmission Planning**

Interregional transmission development plans address the need for unique interregional processes between an RTO and its neighboring transmission systems. These processes typically include joint-system modeling, coordination and exchange of data and cost allocation for interregional projects. MISO and PJM have a joint operating agreement that details how these processes are to be addressed.

Comprehensive interregional transmission planning processes help RTOs understand their impacts on each other. Thus, they are critical for efficient transmission planning within an interconnected grid. These processes are important for MISO and PJM, given the jagged, interwoven nature of the border between these two RTOs – a border that runs through the middle of Illinois. Also, without efficient interregional planning, achieving certain public policy objectives may be difficult. For instance, nature's wind resources are particularly abundant in the western portion of MISO – much more abundant than in the eastern portion of the United States. Thus, achieving various states' renewable energy goals in the most economical way is likely to require more power output from wind farms in the western portion of MISO than MISO can readily absorb without additional transmission capacity within and between it and the eastern load centers of PJM.

**Cost Allocation of Transmission Projects**

Each RTO has FERC-approved methods for allocating the costs of RTO-approved transmission projects, and these methods are dependent on the project type. Cost allocations can vary from direct allocation of costs to project sponsors to spreading the costs across the RTO based on each load serving entity's ("LSEs") share of the RTO's load ("postage stamp methodology"). In most cases, a portion of the costs are allocated to the LSEs located within a zone of the RTO and the rest of the project's costs are shared regionally across the RTO. For example, in the case of PJM, the costs of large transmission projects (double circuit 345 kV and above) are allocated pursuant to an approach that allocates 50 percent of the costs to LSEs based on a load-flow analysis and 50 percent by postage stamp methodology. Another example is MISO's allocation of the costs of transmission facilities that qualify as Multi-Value Projects

(“MVPs”) using a postage stamp methodology.[22] Reliability projects in MISO are allocated directly to LSEs located in the zone in which the upgrade is located. The allocation of interregional project costs are typically based on benefits that accrue to each RTO.

The allocation of transmission project costs has been a particularly contentious issue, with the FERC, transmission owners, state commissions and other RTO stakeholders engaging in litigation for many years. In particular, the ICC has appealed several orders by the FERC approving postage stamp cost allocations in both PJM and MISO to the United States Court of Appeals for the 7th Circuit. In the case of MISO, the appellate court upheld the FERC’s decision to allocate the cost of MVP transmission projects intended to facilitate the public policy initiatives of MISO’s member states on a postage stamp basis. Conversely, in the case of PJM, the appellate court has twice remanded the FERC’s orders approving PJM’s postage stamp allocation of the costs of certain transmission projects back to the FERC.[23] In short, the appellate court required the FERC to address concerns by petitioners that the current cost allocation does not effectively align costs with benefits.

The FERC’s recent Order No. 1000 was also subject to argument before the appellate courts. Order No. 1000 includes several major initiatives, including the expansion of regional and interregional transmission planning, accounting for renewable energy and other public policies, allocating the costs of new transmission lines among customers and ensuring more competition for the construction of those projects.

**Assessing the Need for New Legislation or Regulations**

As described above, the bulk transmission system within and around Illinois is largely outside state jurisdiction. For the most part, transmission planning is performed by RTOs that are not regulated by the ICC or any other state agencies. They are subject to the jurisdiction of the FERC. Stakeholders (including government agencies like the ICC) are permitted to participate in RTO planning in an advisory capacity and to participate in FERC proceedings as interested parties. Once the RTO awards a contract to build a transmission project that falls within or across Illinois borders, Illinois law requires the builders to first obtain permission from the ICC. This gives the ICC the authority and responsibility to find that the project will promote the public convenience and is necessary. The ICC does not see such provisions of law to be legislative impediments. It sees these provisions as reasonable and necessary components of public policy. For instance, the land requirements for utility projects (like new transmission lines) can involve acquiring rights of way over contiguous tracts of private property owned by large numbers of people. In some cases, such rights of way may only be fairly acquired by granting the utility the power of eminent domain. But such power should not be granted if the project is neither necessary nor the least-cost means to provide adequate, reliable, and efficient utility service, or if the project will not promote the development of an effectively competitive electricity market that operates efficiently, is equitable to all customers, and is the least cost means of satisfying those objectives, or if the utility is incapable of efficiently managing and

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[22] MVP projects must meet one of three criteria. (1) Reliably and economically enable regional public policy needs; (2) Provide multiple types of regional economic value; or (3) Provide a combination of regional reliability and economic value.

[23] In the five-plus years since the appellate court has remanded the FERC’s orders on PJM’s cost allocation for 500 kV- and above transmission lines, PJM has modified its cost allocation approach for new transmission expansion projects.

supervising the construction process and financing the proposed construction without significant adverse financial consequences for the utility or its customers. Thus, the ICC identifies no legislative impediments embodied in Illinois law that interferes with the State's or grid operators' ability to design and expand transmission resources that promote the electric industry's ability to move power to, from and through Illinois.

## Impacts of Nuclear Power Plant Closures on Electric Rates

### Illinois' Generating Capacity

Within Illinois, there are six nuclear power stations housing a total of eleven nuclear generating units that are currently operational. As shown in the chart below, these units are licensed by the NRC to operate for another 7 to 18 years. Having been fairly recently renewed, the licenses of the oldest of these units (Dresden and Quad Cities) will expire the furthest into the future. However, in the United States Environmental Protection Agency's ("EPA's") Integrated Planning Model ("IPM") v.5.13 base case scenario, the newer units' licenses would also be renewed and would retire after 60 years of operation.[24] This report relaxes that assumption and considers the possibility of earlier retirement.

The combined generating capacity of these nuclear power stations is approximately 12,000 Megawatts. The ratings of each unit are shown in the table, below. Not shown are three Illinois nuclear generating units that are no longer in commercial operation: Dresden Unit 1 and Zion Units 1 & 2. Dresden Unit 1, with a generating capacity of 210 MW, remained operational for approximately 19 years between 1960 and 1978. The two Zion units, each with a generating capacity of 1,040 MW, remained operational for approximately 23 years between 1973 and 1997. Currently, they are undergoing decommissioning.

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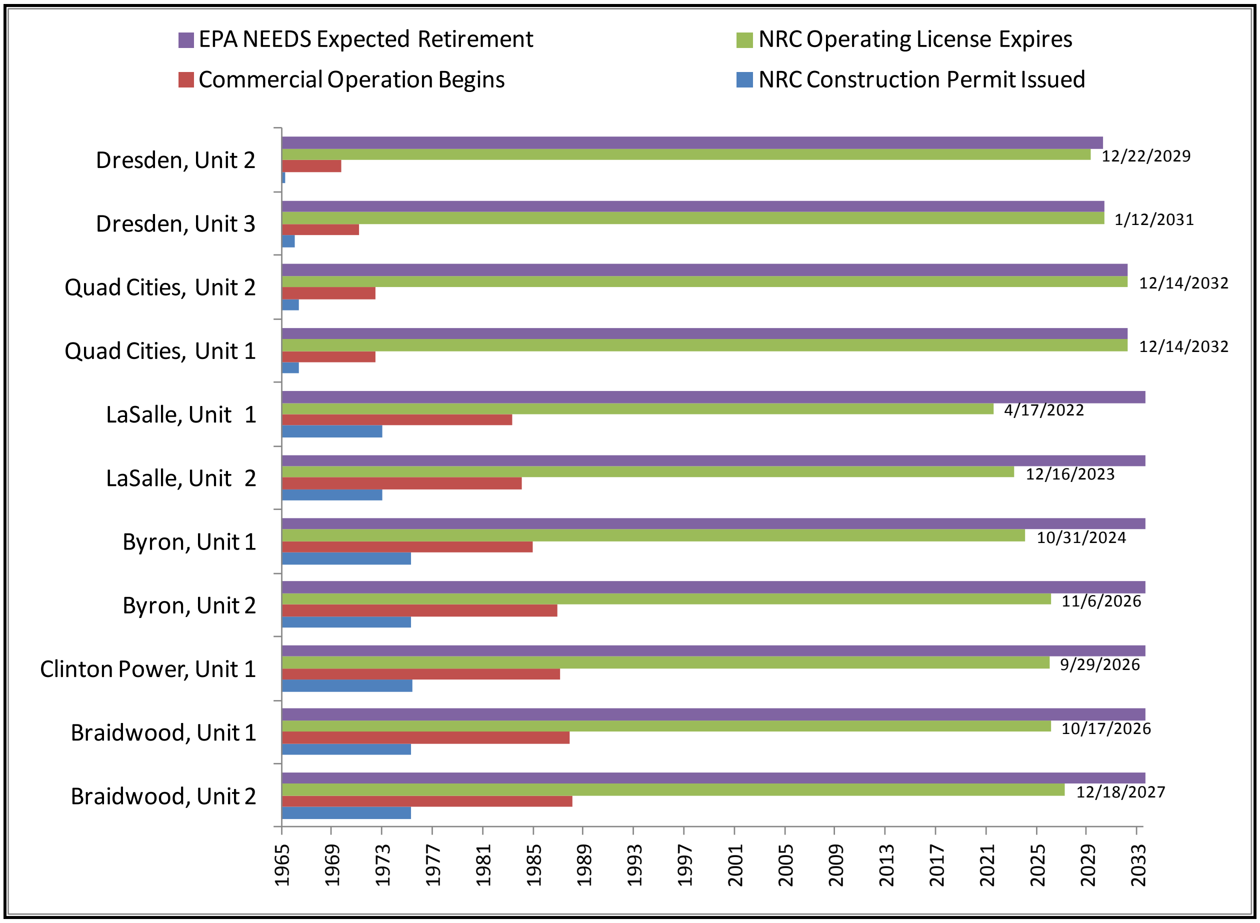
[24] IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. IPM is used by the EPA to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), mercury (Hg), and HCl from the electric power sector. According to the EPA, the new base case (v.5.13) incorporates structural improvements and data updates with respect to the previous version (v.4.10). See the EPA web site for more detail: http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev513.html




| UNIT NAME | YEARS IN OPERATION | NAMEPLATE RATING MW | SUMMER CAPABILITY MW | WINTER CAPABILITY MW |
|---|---|---|---|---|
| Braidwood, Unit 1 | 26 | 1,225 | 1,178 | 1,208 |
| Braidwood, Unit 2 | 25 | 1,225 | 1,152 | 1,176 |
| Byron, Unit 1 | 28 | 1,225 | 1,164 | 1,188 |
| Byron, Unit 2 | 27 | 1,225 | 1,136 | 1,158 |
| Clinton Power, Unit 1 | 26 | 1,138 | 1,065 | 1,078 |
| Dresden, Unit 2 | 44 | 1,009 | 883 | 883 |
| Dresden, Unit 3 | 42 | 1,009 | 867 | 867 |
| LaSalle, Unit 1 | 30 | 1,170 | 1,137 | 1,152 |
| LaSalle, Unit 2 | 29 | 1,170 | 1,140 | 1,161 |
| Quad Cities, Unit 1 | 41 | 1,009 | 908 | 908 |
| Quad Cities, Unit 2 | 41 | 1,009 | 911 | 911 |

In addition to the nuclear stations, there are over 200 non-nuclear generating facilities with nameplate capacities[25] in excess of 100 MW and approximately 500 smaller facilities that are counted by the United States Energy Information Administration ("EIA").[26] The non-nuclear facilities account for roughly 76% of the total nameplate capacity of Illinois generating facilities. While Illinois' fleet of nuclear power generating units accounts for approximately 24% of the nameplate capacity within Illinois (which is less than that of either the coal-fueled or the natural gas-fueled generating fleets), over the course of a year, the nuclear plants actually produce more Megawatt-Hours ("MWH") of electricity than the coal and natural gas plants combined. This reflects the fact that the nuclear stations operate nearly continuously while fossil-fuel plants (particularly certain natural gas facilities) operate in more limited instances.

**Electric Generating Units within Illinois**

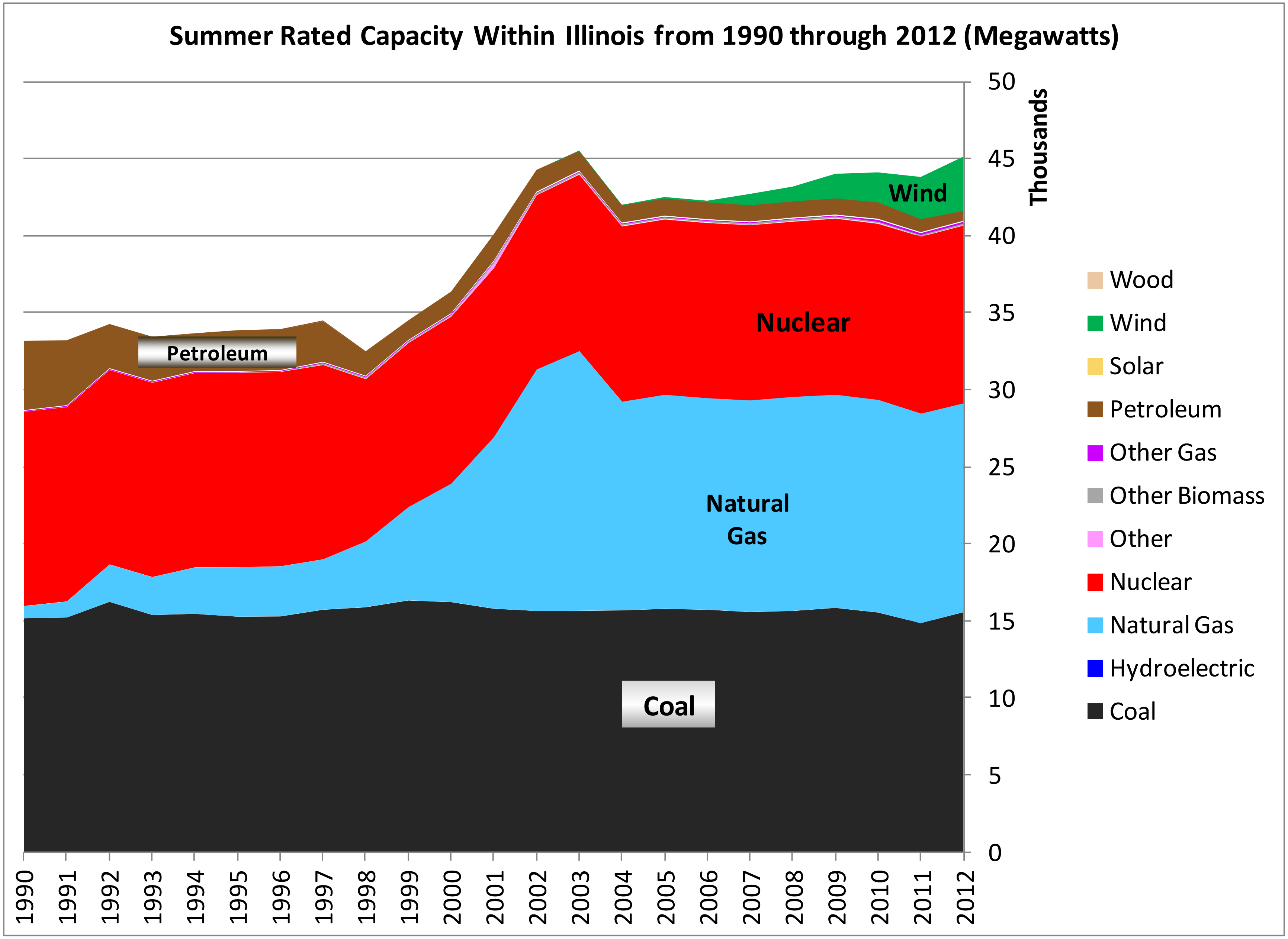
**Nameplate Capacity and Annual Production, by Primary Fuel**

| | Capacity | Energy Production | | Capacity | Energy Production | |
|---|---|---|---|---|---|---|
| **Primary Fuel** | **MW** | **2013 MWHs** | **2012 MWHs** | **%** | **2013 %** | **2012 %** |
| Coal | 17,356 | 87,989,021 | 80,826,778 | 34.0% | 43.4% | 40.9% |
| Natural Gas | 16,688 | 6,661,218 | 11,188,975 | 32.7% | 3.3% | 5.7% |
| Nuclear | 12,415 | 97,131,436 | 96,401,309 | 24.3% | 47.9% | 48.8% |
| Wind | 3,545 | 9,607,015 | 7,726,810 | 6.9% | 4.7% | 3.9% |
| Petroleum | 780 | 75,803 | 71,382 | 1.5% | 0.0% | 0.0% |
| Other Biomass | 125 | 623,556 | 615,193 | 0.2% | 0.3% | 0.3% |
| Other Gas | 111 | 332,766 | 293,590 | 0.2% | 0.2% | 0.1% |
| Hydroelectric | 40 | 140,767 | 111,208 | 0.1% | 0.1% | 0.1% |
| Solar | 29 | 63,636 | 30,657 | 0.1% | 0.0% | 0.0% |
| Other | 10 | 265,386 | 299,461 | 0.0% | 0.1% | 0.2% |
| Total | 51,099 | 202,890,604 | 197,565,363 | 100% | 100% | 100% |

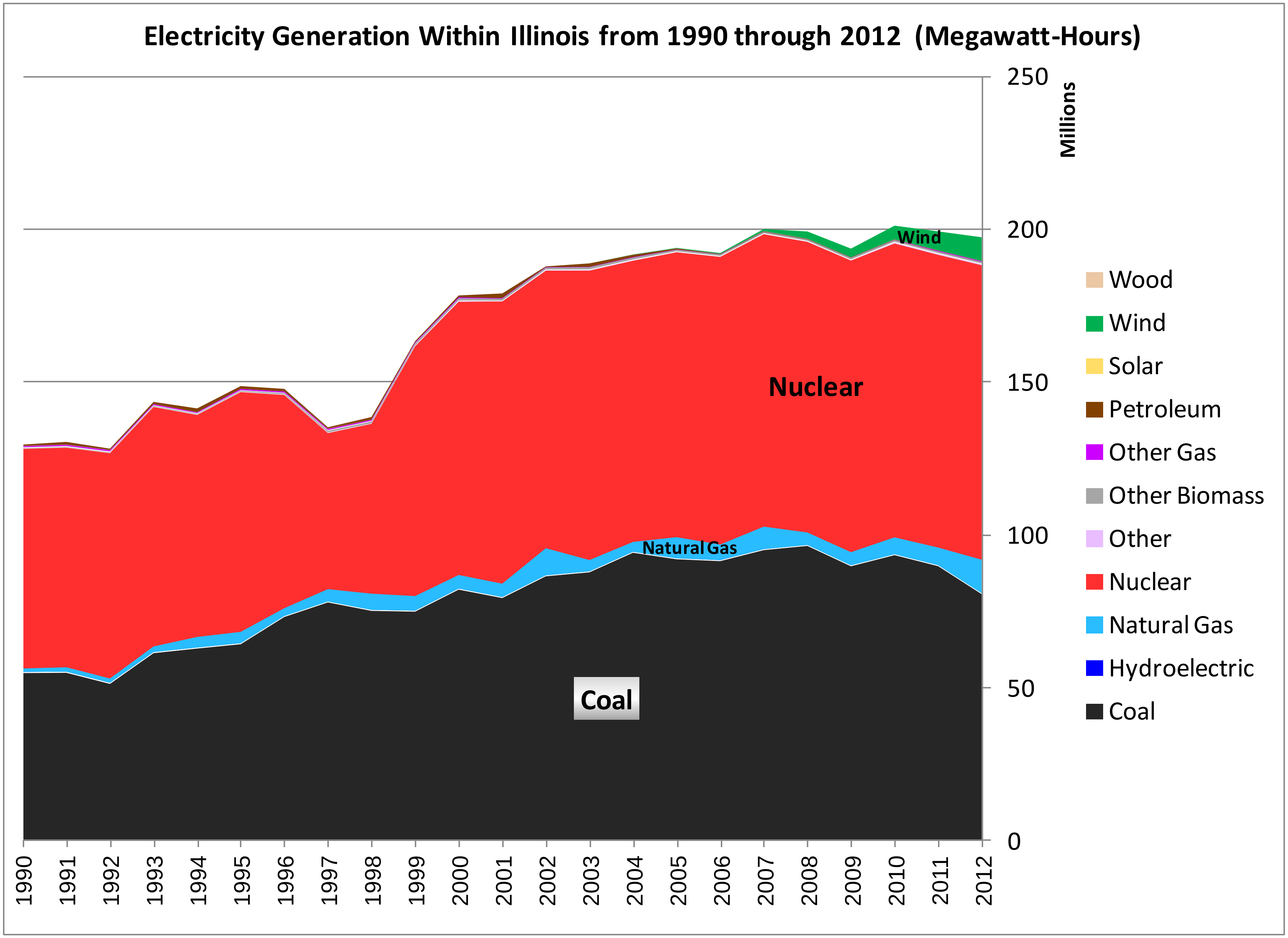
The following two charts show how the capacity and annual production of Illinois generating facilities changed between 1990 and 2012. In particular, note the marked increase in natural gas-fired generation capacity but the lack of growth in the annual quantity of electricity produced with those plants. Also note the appearance of and marked increase in wind turbine capacity and production since the mid 2000s.

[25] Capacity is the maximum electric output a generator can produce under specific conditions. Nameplate capacity is determined by the generator's manufacturer and indicates the maximum output a generator can produce without exceeding design thermal limits. Source: U.S. Energy Information Administration.

[26] Based on responses to the 2012 Form EIA-860.



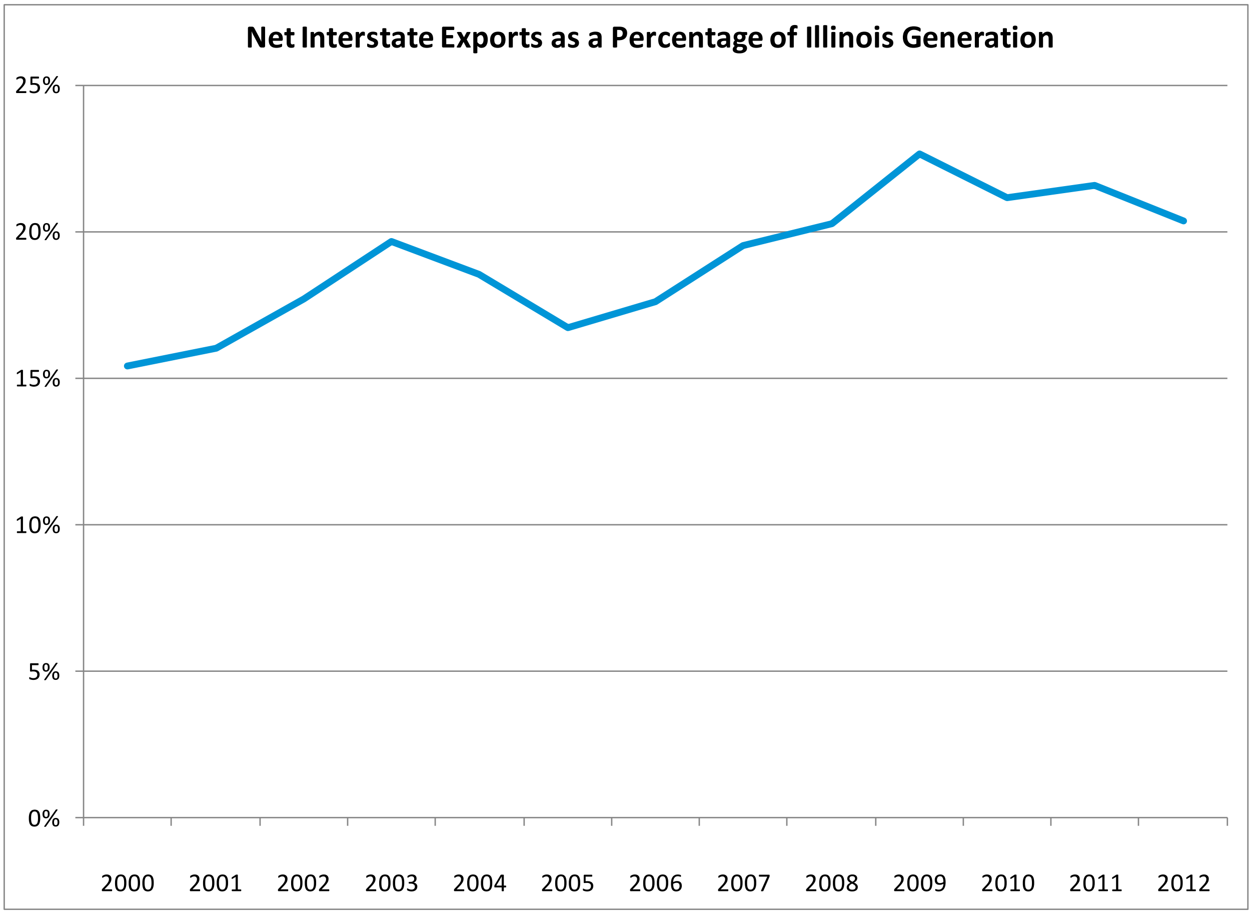
Summer Rated Capacity Within Illinois from 1990 through 2012 (Megawatts)
Thousands
0
5
10
15
20
25
30
35
40
45
50
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Petroleum
Nuclear
Wind
Natural Gas
Coal
Wood
Wind
Solar
Petroleum
Other Gas
Other Biomass
Other
Nuclear
Natural Gas
Hydroelectric
Coal



Electricity Generation Within Illinois from 1990 through 2012 (Megawatt-Hours)
Millions
250
200
150
100
50
0
Wind
Nuclear
Natural Gas
Coal
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
Wood
Wind
Solar
Petroleum
Other Gas
Other Biomass
Other
Nuclear
Natural Gas
Hydroelectric
Coal

**Regional Generating Capacity**

Illinois distribution companies are also interconnected with electric generating facilities outside of Illinois through a vast electric transmission network (the grid). Since at least 2000, Illinois has generally been a net exporter rather than a net importer of electricity, as shown in the following chart. Illinois' position as a net exporter of electricity reflects Illinois' relative abundance of "base-load" generating capacity, with relatively low operating costs.




Ameren Illinois is a member of MISO, which dispatches generating units capable of producing over 100,000MW of power.[27] MISO coordinates the movement of wholesale electricity within, to, and from nine local resource zones ("LRZs"), spanning all or parts of fifteen U.S. states and one Canadian province. Ameren Illinois comprises Zone 4. Total import capability into Zone 4 from other MISO zones is 3,025 MW.

ComEd is a member of PJM, which dispatches generating units capable of producing over 180,000 MW of power.[28] It coordinates the movement of wholesale electricity within, to,

[27] NERC states that MISO's 2013 generating capacity was 106,087 MW. (2013 Long-Term Reliability Assessment, December 2013, p. 52). In a January 2014 corporate fact sheet, MISO lists its generating capacity as 175,436 MW (market) and 200,906 MW (reliability).

[28] NERC states that PJM's 2013 generating capacity was 185,164 MW. (2013 Long-Term Reliability Assessment, December 2013, p.123.)

and from 22 PJM zones, spanning all or parts of 13 states and the District of Columbia. The ComEd Zone is also one of PJM's 27 Locational Deliverability Areas ("LDAs"), for which PJM assesses limitations on imports from other areas of PJM. PJM measures the total import capability into LDAs using a concept called the Capacity Emergency Transfer Limit ("CETL"). For 2017, PJM determined ComEd's CETL to be 7,020 MW.[29]

PJM and MISO, which jointly control over 280,000MW of generating capacity, are also interconnected with each other and have been working toward establishing a more integrated "Joint and Common Market." According to a MISO report for the Joint and Common Stakeholders Group[30], MISO LRZs with ties to PJM are capable of exporting as much as 7,734 MW to the Western Load Deliverability Area of PJM (of which ComEd is a part). Also, MISO LRZs with ties to PJM are capable of importing as much as 12,552 MW from PJM.

### Ownership and Control of Generating Resources

The six nuclear power stations in Illinois are all owned by Exelon Generation Company, LLC ("ExGen"), with the exception of Quad Cities, which is owned by both ExGen (75%) and Mid-American Energy Company (25%). ExGen is owned by Exelon Corp. Other non-nuclear utility-scale electric generating facilities in Illinois are owned by several dozen companies and municipalities. "Utility-scale" facilities, considered here to be those with generating capacity in excess of 100 MW, comprise over 90% of total capacity within Illinois. Major owners of non-nuclear generating capacity include subsidiaries of Dynegy (> 8,000 MW) and NRG Energy, Inc. (> 5,000 MW). Throughout the United States, generating assets are owned by hundreds of public, private, and cooperative utilities and more than 1,000 independent power generating companies. Additionally, end-users (from large industrial to households) own utility-scale and smaller generating equipment.

### Current Profitability of Existing Nuclear Power Plants

To devise policy options for addressing the potential closure of existing nuclear power plants, it is necessary to examine the potential cause of such closures, beginning with an examination of the profitability of Illinois' nuclear power plants. Profitability, in this context, is defined in terms of revenues relative to the costs that can be avoided if a plant is decommissioned.[31]

#### Avoidable Costs

For the purpose of examining the potential closure of a generating plant, avoidable costs include fuel expenses, variable operating and maintenance expenses, and fixed operating and maintenance expenses (together, "production costs"). Avoidable costs may also include future

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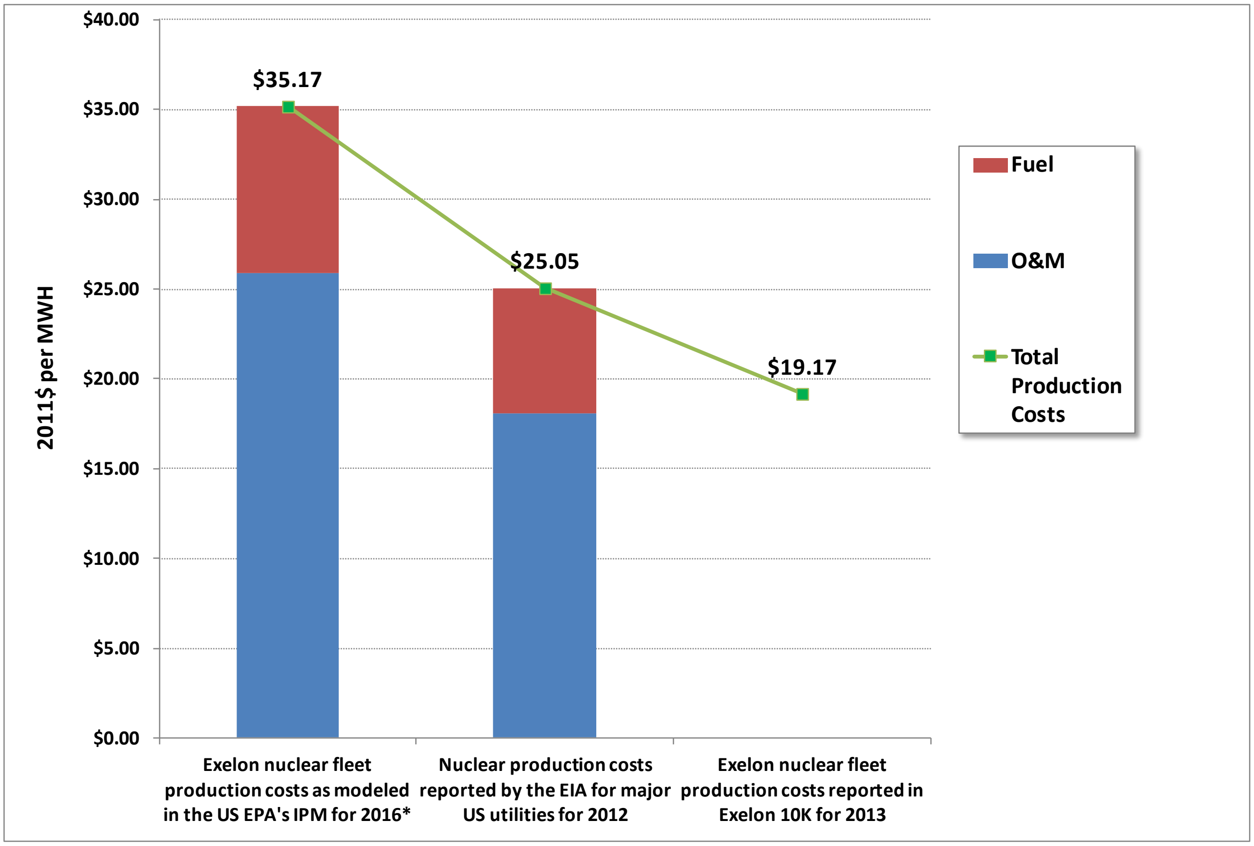
[29] The CETL for the ComEd Zone is an estimate of the amount of emergency power that can be reliably transferred to the ComEd Zone from the remainder of PJM and the areas adjacent to PJM in the event of a generation deficiency in the ComEd Zone.

[30] http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20140414/20140414-capacity-deliverability-miso-fact-finding-1-and-2-report.ashx, p. 14

[31] Nuclear decommissioning is the process whereby a nuclear power plant is safely removed from service and dismantled, reducing residual radioactivity to a level that permits release of the property and termination of the operating license. Source: U.S. Nuclear Regulatory Commission.

expenditures for capital additions needed to keep existing plants operating. Avoidable costs exclude any capital investments that have already been made or the amortization of those costs because such costs cannot be avoided by closing the facility. In the case of nuclear power plants, the most significant component of production costs is fixed operating and maintenance expenses ("FOM"), which accounts for about two-thirds to seventy-five percent of total production costs. The second most significant component is fuel costs, which accounts for about twenty-five percent to one-third of total production costs. Variable operating and maintenance expenses ("VOM") account for less than 2% of total production costs.

Data pertaining to nuclear power plant production costs were obtained from three sources: (1) Exelon SEC filings; (2) EIA statistics; and (3) the EPA's Integrated Planning Model ("IPM").[32] Some of these data are summarized in the following chart.




* Note: For approximately one-half of the Exelon generating units, the O&M expenditures in the first bar, showing "Exelon nuclear fleet production costs as modeled in the EPA's IPM for 2016," include amortization of life-extending investments made after 2010 and before 2016. For some if not all of these plants, these life-extending investments would be sunk prior to a decision to decommission the unit. Hence, they would be irrelevant to the decision. Without these amortized investments, O&M expenditures would be 6% less than as shown in the chart.

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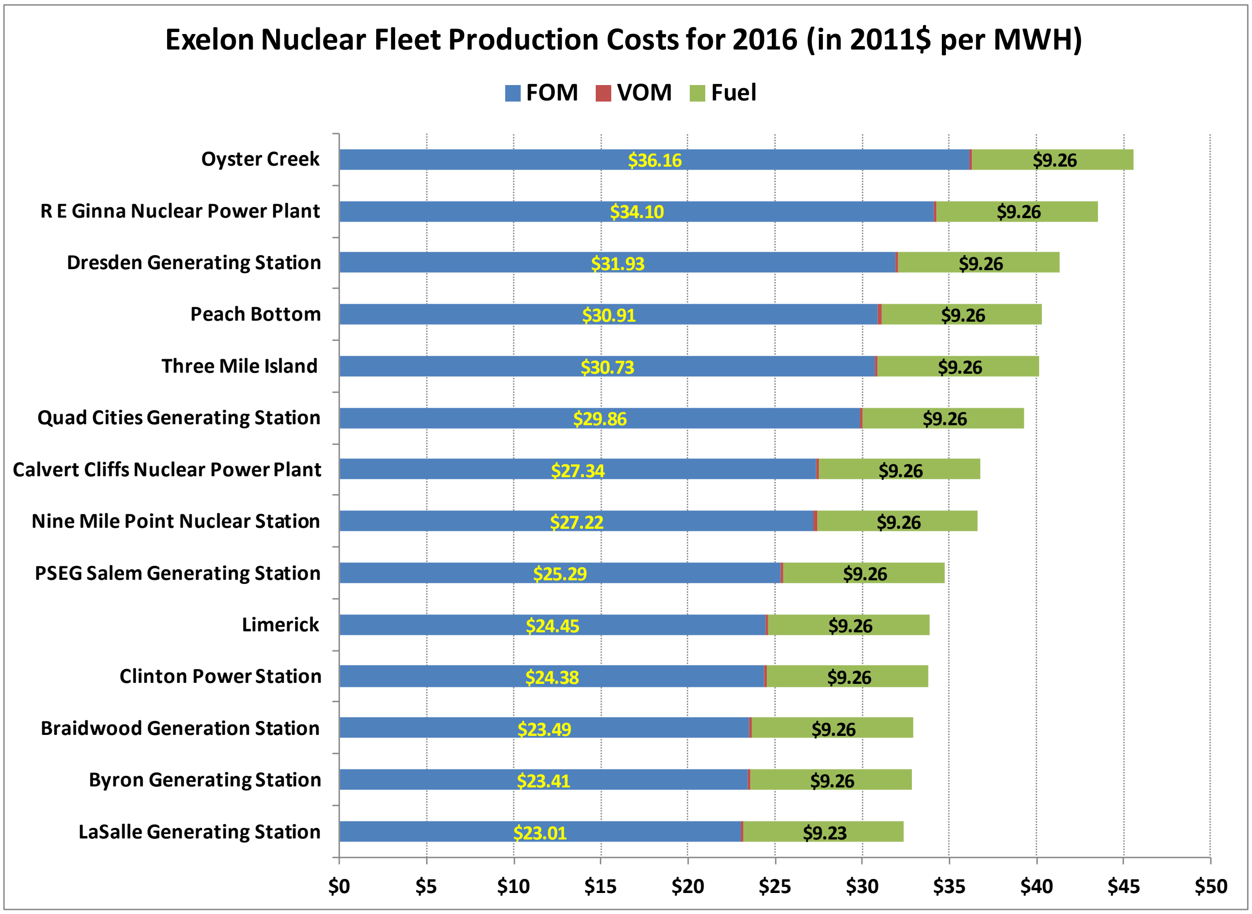
[32] Data from a fourth source was also reviewed, late in the process of completing this report. They are embedded in the database used by MISO for its study of impact of the Illinois nuclear plant closures. That study is described later in this report. The nuclear power plant production costs from MISO's database fall between the levels revealed in Exelon's SEC filings and in the EIA statistics described in this section.

Finding unit-specific data to determine the ongoing costs of nuclear units in Illinois proved challenging. However, as part of its tools for proposing and evaluating environmental regulations, the EPA has developed an Integrated Planning Model ("IPM"), which includes estimates of unit-specific operating costs for each of the existing nuclear units in the United States and Canada. These EPA cost figures are considerably higher than the cost figures from Exelon's SEC filings and the EIA's statistics. [33] The table and chart below show some of these EPA data for generating stations in Exelon's nuclear fleet, projected to 2016. Note that, with the exceptions of Quad Cities and Dresden, Exelon's Illinois plants are the lowest cost units listed.

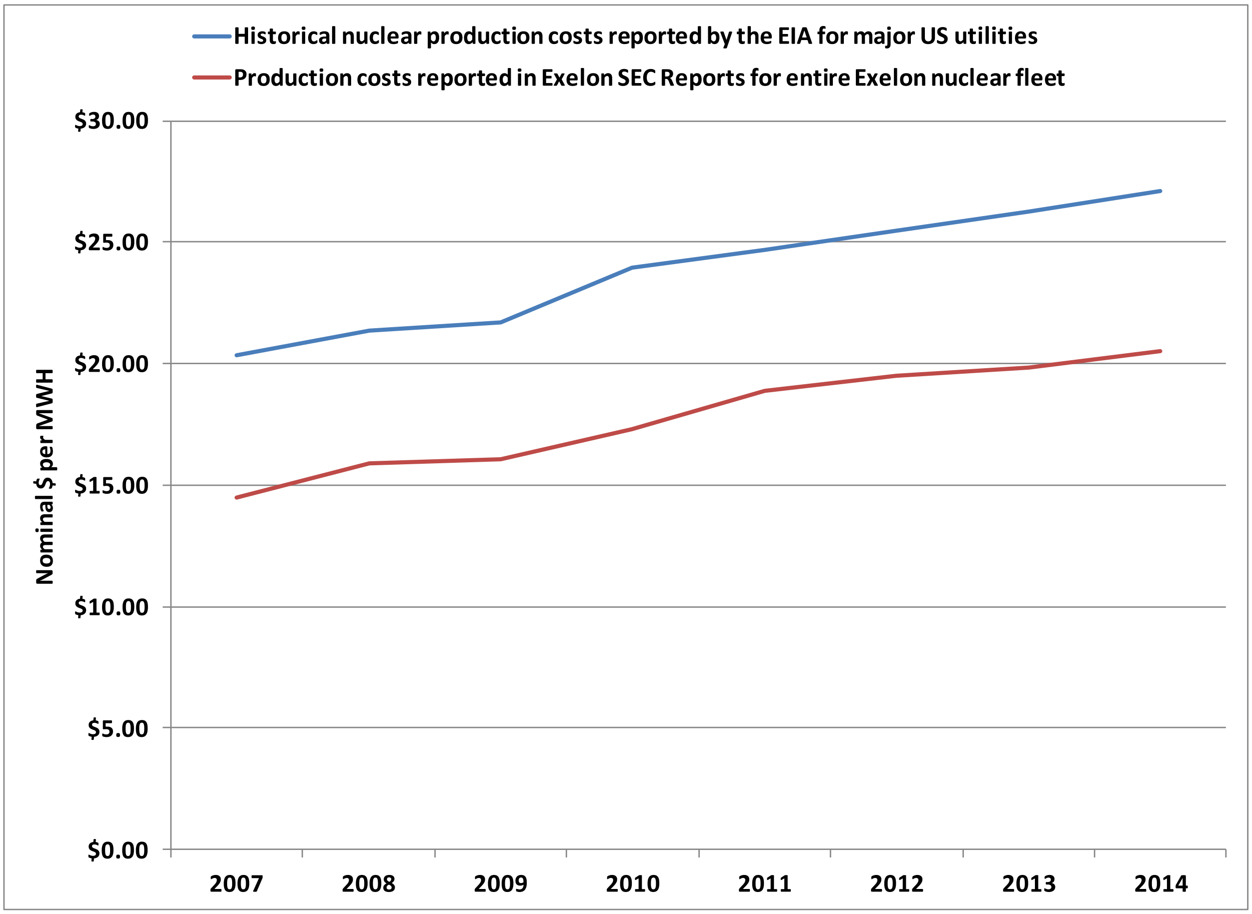
[33] The EPA cost figures are also higher than those found in the fourth data source, cited in the previous footnote.

**EPA Modeled Costs of Exelon's Existing Nuclear Fleet**
projected to 2016 and presented in 2011$

| Region of the Grid | Generating Unit | Capacity MW | 2016 Output GWH | FOM $MM/yr | VOM $MM/yr | Fuel $MM/yr | Total Cost $MM/Yr | Total Cost $/MWH |
|---|---|---|---|---|---|---|---|---|
| MIS_IL | Clinton 1 | 1,065 | 8,704 | 212.2 | 1.6 | 80.6 | 294.4 | $33.82 |
| PJM_COMD | Braidwood 1 | 1,178 | 9,845 | 228.7 | 1.7 | 91.2 | 321.6 | $32.66 |
| | Braidwood 2 | 1,152 | 9,415 | 223.6 | 1.7 | 87.2 | 312.5 | $33.19 |
| | Byron 1 | 1,164 | 9,564 | 226.2 | 1.7 | 88.6 | 316.4 | $33.08 |
| | Byron 2 | 1,136 | 9,523 | 220.7 | 1.6 | 88.2 | 310.6 | $32.61 |
| | Dresden 2 | 867 | 7,162 | 230.9 | 1.3 | 66.3 | 298.5 | $41.68 |
| | Dresden 3 | 867 | 7,306 | 230.9 | 1.3 | 67.7 | 299.9 | $41.05 |
| | LaSalle 1 | 1,118 | 9,343 | 216.2 | 1.6 | 86.2 | 304.1 | $32.55 |
| | LaSalle 2 | 1,120 | 9,471 | 216.6 | 1.6 | 87.4 | 305.6 | $32.27 |
| | Quad Cities 1 | 908 | 7,461 | 224.0 | 1.3 | 69.1 | 294.4 | $39.45 |
| | Quad Cities 2 | 911 | 7,565 | 224.7 | 1.3 | 70.1 | 296.1 | $39.14 |
| PJM_WMAC | Three Mile Island 1 | 805 | 6,579 | 202.2 | 1.2 | 60.9 | 264.3 | $40.17 |
| PJM_EMAC | Limerick 1 | 1,146 | 9,396 | 229.1 | 1.7 | 87.0 | 317.8 | $33.82 |
| | Limerick 2 | 1,150 | 9,379 | 229.9 | 1.7 | 86.8 | 318.4 | $33.95 |
| | Oyster Creek 1 | 393 | 3,068 | 111.0 | 0.6 | 28.4 | 139.9 | $45.61 |
| | Peach Bottom 2 | 1,122 | 9,327 | 286.7 | 1.6 | 86.4 | 374.6 | $40.17 |
| | Peach Bottom 3 | 1,122 | 9,219 | 286.7 | 1.6 | 85.4 | 373.7 | $40.53 |
| | PSEG Salem 1 | 1,166 | 9,192 | 232.3 | 1.7 | 85.1 | 319.1 | $34.72 |
| | PSEG Salem 2 | 1,160 | 9,134 | 231.1 | 1.7 | 84.6 | 317.4 | $34.74 |
| PJM_SMAC | Calvert Cliffs 1 | 855 | 7,138 | 218.9 | 1.2 | 66.1 | 286.3 | $40.11 |
| | Calvert Cliffs 2 | 850 | 7,066 | 169.4 | 1.2 | 65.4 | 236.0 | $33.40 |
| NY_Z_A&B | Ginna 1 | 581 | 4,646 | 158.4 | 0.8 | 43.0 | 202.3 | $43.54 |
| NY_Z_C&E | Nine Mile Point 1 | 1,143 | 9,322 | 227.7 | 1.7 | 86.3 | 315.7 | $33.87 |
| | Nine Mile Point 2 | 630 | 5,066 | 163.9 | 0.9 | 46.9 | 211.7 | $41.78 |
| | All Exelon | 23,609 | 193,894 | 5,202.1 | 34.2 | 1,794.9 | 7,031.3 | $36.26 |




The other two sources of cost information mentioned above -- Exelon SEC filings and EIA statistics -- provide no generating unit-specific details, but they do provide historical data for 2007 through 2013 and parts of 2014, as shown below.




Note: Data from Exelon SEC reports are through June 2014. Data from the EIA are through 2013; and the 2014 value is estimated as the 2013 value multiplied by one plus the rate of change between 2012 and 2013.

### Revenues

Most of the revenues earned through operation of nuclear power plants are derived from electric energy sales. A second major source of revenues can be sales of "capacity," which is to say the ability and willingness of the plant owner to make a generating facility fully available for energy production whenever it is needed by the purchaser of the "capacity" (except during scheduled maintenance periods).

#### Energy market revenues

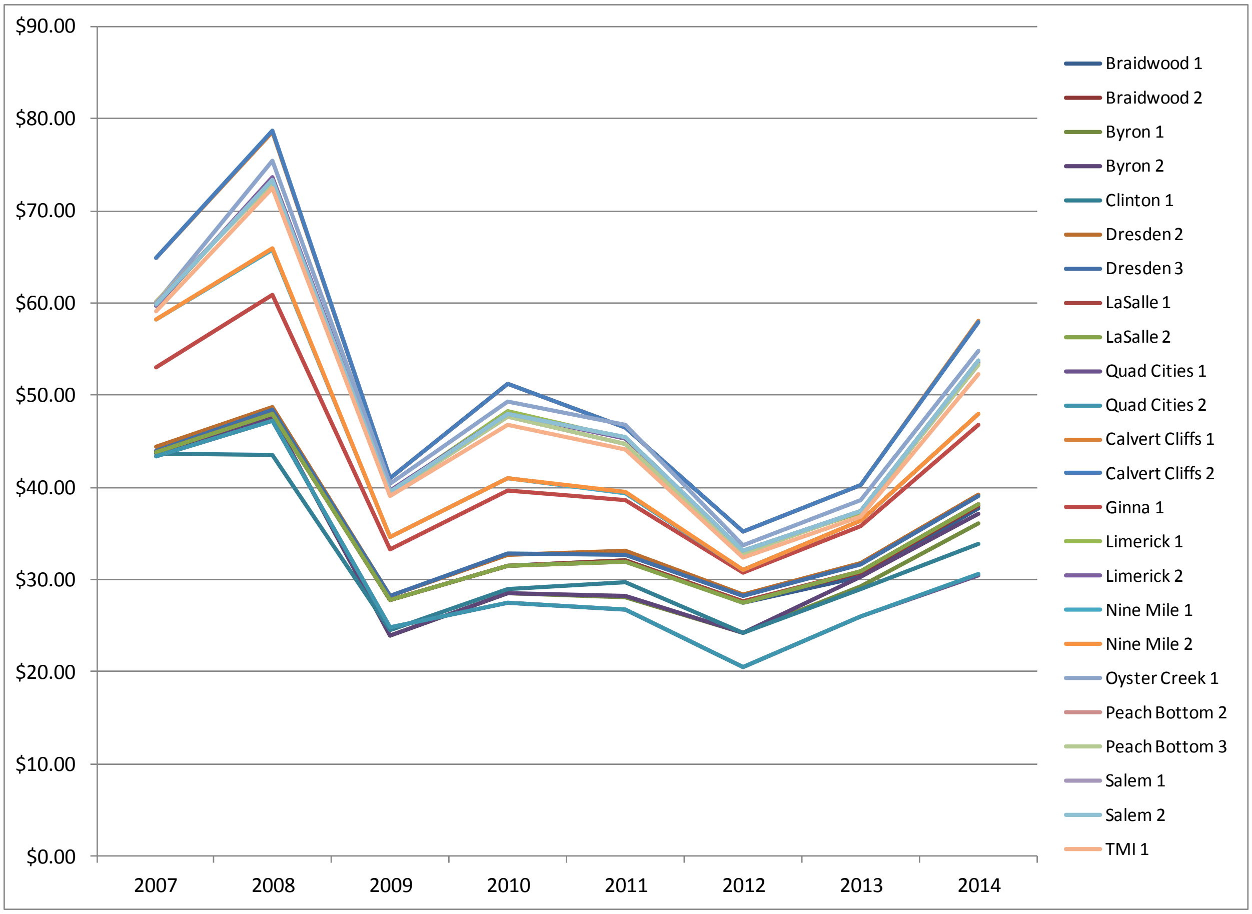
Electric energy sales can take place through a variety of contractual forms. They can be arranged through "over-the-counter" markets, organized exchanges, RTO spot markets, negotiations, auctions, and requests for proposals. The sales may be scheduled for delivery over a single hour, a day, a month, or a year. They can be arranged a day before delivery is to begin or up to years before delivery is to begin. Such sales can be tied to particular generating facilities or to more general delivery locations (such as the ComEd Zone of PJM). While Exelon's business model may involve some or all of the above avenues, this report relies primarily on the day-ahead locational marginal price ("LMP") wholesale spot markets operated by the RTOs, since they are readily available.

LMPs within each RTO reflect the value of energy at the specific locations and times it is delivered. When the lowest-priced electricity can reach all locations, LMPs are the same across the entire PJM grid and are equal to the marginal cost of generation at that time. However, when heavy use of the transmission system causes congestion, the lowest-priced energy cannot flow freely to some locations. In that case, more expensive electricity is ordered to meet demand. As a result, LMPs are higher in those locations contributing the most to the congestion.

The annual average LMPs for each of Exelon's nuclear units is shown in the following chart, which reveals considerable variation between years and between generating units. In particular, the chart shows a distinct drop in LMPs between the first two years and next five years, indicting a drop in revenues for all of Exelon's nuclear power stations. Comparing the average from 2007 through 2008 to the average from 2009 through 2013, wholesale spot market prices available to Exelon's nuclear plants declined by roughly 38%. In addition, the chart shows that LMPs at Exelon's Illinois nuclear units are generally less than LMPs for Exelon's eastern nuclear units. In fact, the Quad Cities units receive the lowest energy prices of all the Exelon nuclear units, with the Clinton and Byron units second and third lowest respectively. These are also the three Illinois nuclear power stations that Exelon has indicated an interest in retiring.[34]

[34] See, for example, the Crain's article, "Exelon warns state it may close 3 nukes," by Steve Daniels, March 1, 2014. http://www.chicagobusiness.com/article/20140301/ISSUE01/303019987/exelon-warns-state-it-may-close-3-nukes

**Locational Marginal Prices for Energy Produced by Exelon Nuclear Units**




Note: For 2014, values after July were projected using data for August through December of 2013.

**Capacity market revenues**

For revenue associated with capacity sales, the analysis assumes that Exelon was able to sell its nuclear capacity in the RTOs' organized markets at market clearing prices.[35] For the units located in Illinois, with the exception of the Clinton power station, such sales would take place through PJM's annual "reliability pricing model" ("RPM") capacity auction, which has been in existence since 2007. Clinton is part of the MISO market, but MISO only recently adopted a capacity auction. Thus, the results of the IPA's capacity RFPs on behalf of Ameren

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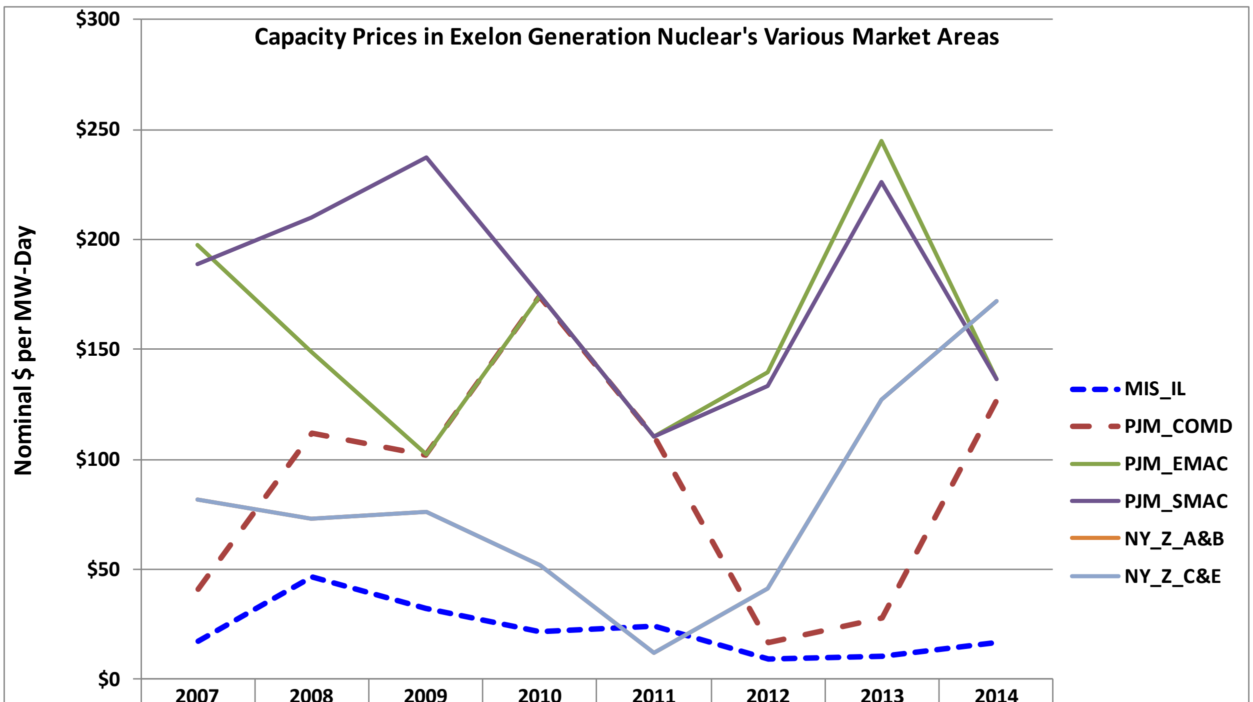
[35] However, on May 29, 2014, Exelon announced that it's Quad Cities (U1 & U2), Byron (U1&U2) and Oyster Creek nuclear plants did not clear the PJM capacity auction for the delivery period 2017/2018. (http://phx.corporate-ir.net/phoenix.zhtml?c=124298&p=irol-EventDetails&EventId=5159617) That is, Exelon's price bids for these units exceeded the auction-clearing price. On the other hand, according to an article in RTO Insider, analysts for UBS Securities reportedly indicated that Exelon "couldn't have played its hand any better," As explained in the article: "UBS said Exelon's ideal strategy was to "withhold" 4,457 MW of its 25,000 MW PJM fleet — almost exactly the 4,225 MW of capacity that failed to clear. UBS Securities calculated that Exelon will earn $148 million more in capacity revenues in 2017 than it would have earned had all of its capacity cleared." ("How Exelon Won by Losing: Capacity Revenues Jump Despite Nukes' Failure to Clear Auction," *RTO Insider*, June 3, 2014, by Rich Heidorn Jr. and Ted Caddell. http://www.rtoinsider.com/exelon-pjm-capacity-mkt/ ).

Illinois Company were used for Clinton for all but the most recent year. Prices available to Exelon nuclear units outside of Illinois (in other parts of PJM or in the New York ISO) were also examined.

Based on the above-cited data sources, the following table summarizes capacity prices in the areas where Exelon has an opportunity to sell capacity from its nuclear facilities. It shows the revenues that could be earned each day of the year for each MW of capacity sold. The line labeled "MIS_IL" represents MISO Illinois where the Clinton power station is located, while "PJM_COMD" represents the ComEd Zone within PJM where the rest of Exelon's Illinois nuclear power stations are located. The chart reveals significant variation between years, but no obvious trend. It also shows the considerable difference between NY ISO, PJM, and MISO capacity prices. In particular, capacity prices are generally lower in MISO than the other RTOs and usually lower in Illinois than in the East where Exelon's other nuclear power stations are located.

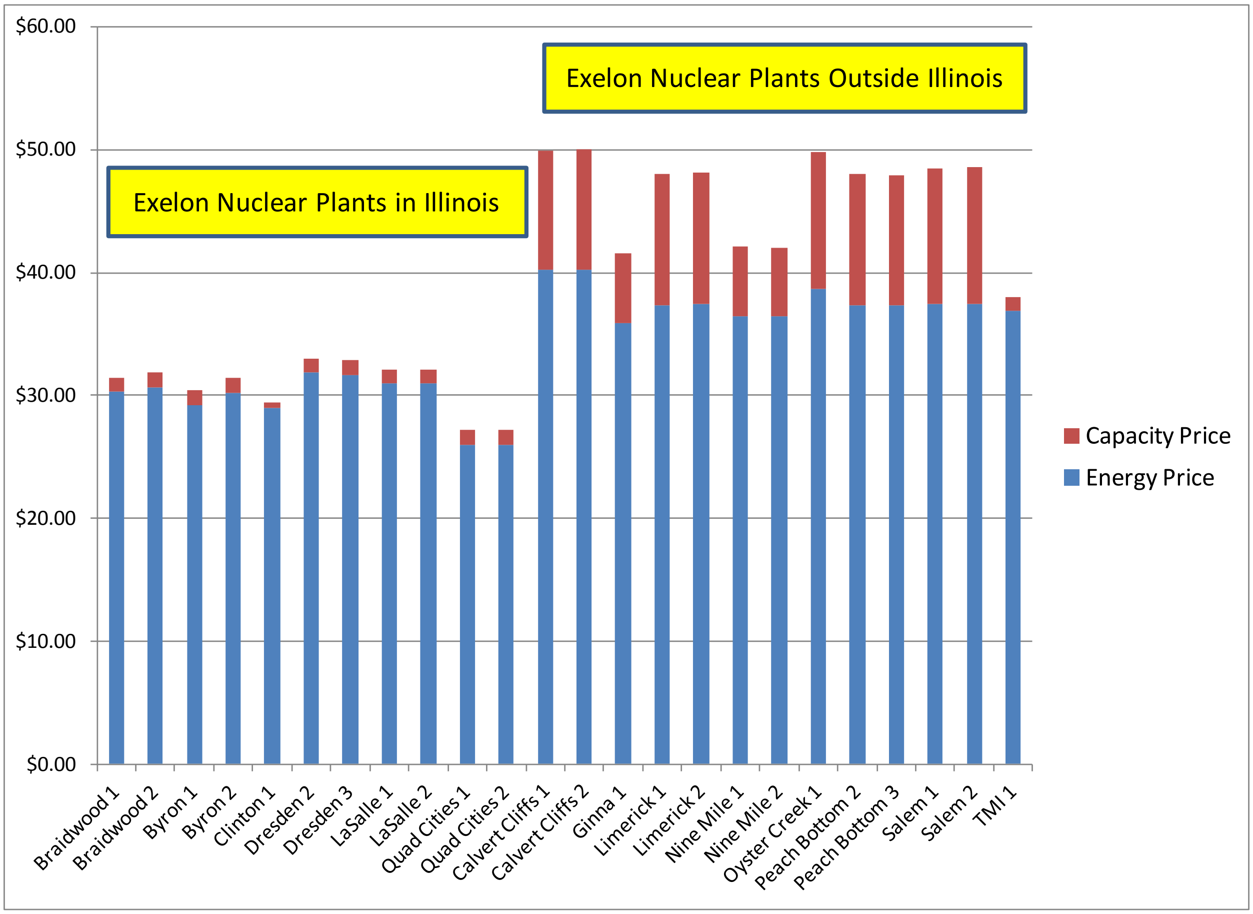



| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|
| MIS_IL | 16.97 | 46.54 | 32.06 | 21.86 | 23.80 | 9.32 | 10.13 | 16.75 |
| PJM_COMD | 40.80 | 111.92 | 102.04 | 174.29 | 110.00 | 16.46 | 27.73 | 125.99 |
| PJM_EMAC | 197.67 | 148.80 | 102.04 | 174.29 | 110.00 | 139.73 | 245.00 | 136.50 |
| PJM_SMAC | 188.54 | 210.11 | 237.33 | 174.29 | 110.00 | 133.37 | 226.15 | 136.50 |
| NY_Z_A&B | 81.98 | 72.97 | 76.31 | 51.51 | 11.70 | 41.03 | 127.21 | 171.77 |
| NY_Z_C&E | 81.98 | 72.97 | 76.31 | 51.51 | 11.70 | 41.03 | 127.21 | 171.77 |

Source: ICC records and RTO capacity market websites.

**Energy plus capacity market revenues**

In the previous subsections, energy prices were expressed in dollars per MW-hours, while capacity prices were expressed in dollars per MW-day. These are not directly comparable. After making the necessary conversion, the following chart combines energy and capacity prices for 2013. The chart shows that energy and capacity prices combined are generally lower in Illinois than in the East where Exelon's other nuclear power stations are located.




**Net Revenue**

The cost and price information described above is combined in this section to assess the profitability of Exelon's nuclear fleet. Several caveats should be noted when viewing this information. First, Exelon may not receive the prices recorded in RTO records if it sells energy under other types of contracts or engages in hedging activities. Second, the unit-specific cost estimates from the EPA are projections for 2016. Although the EPA cost projections have been discounted for inflation for purposes of comparison to the EIA and Exelon costs for the 2007 through 2014 period, they are still considerably higher than the costs reported by these other sources.[36] Furthermore, some of the 2014 values are projections or are limited to the first 6 or 7 months of 2014.

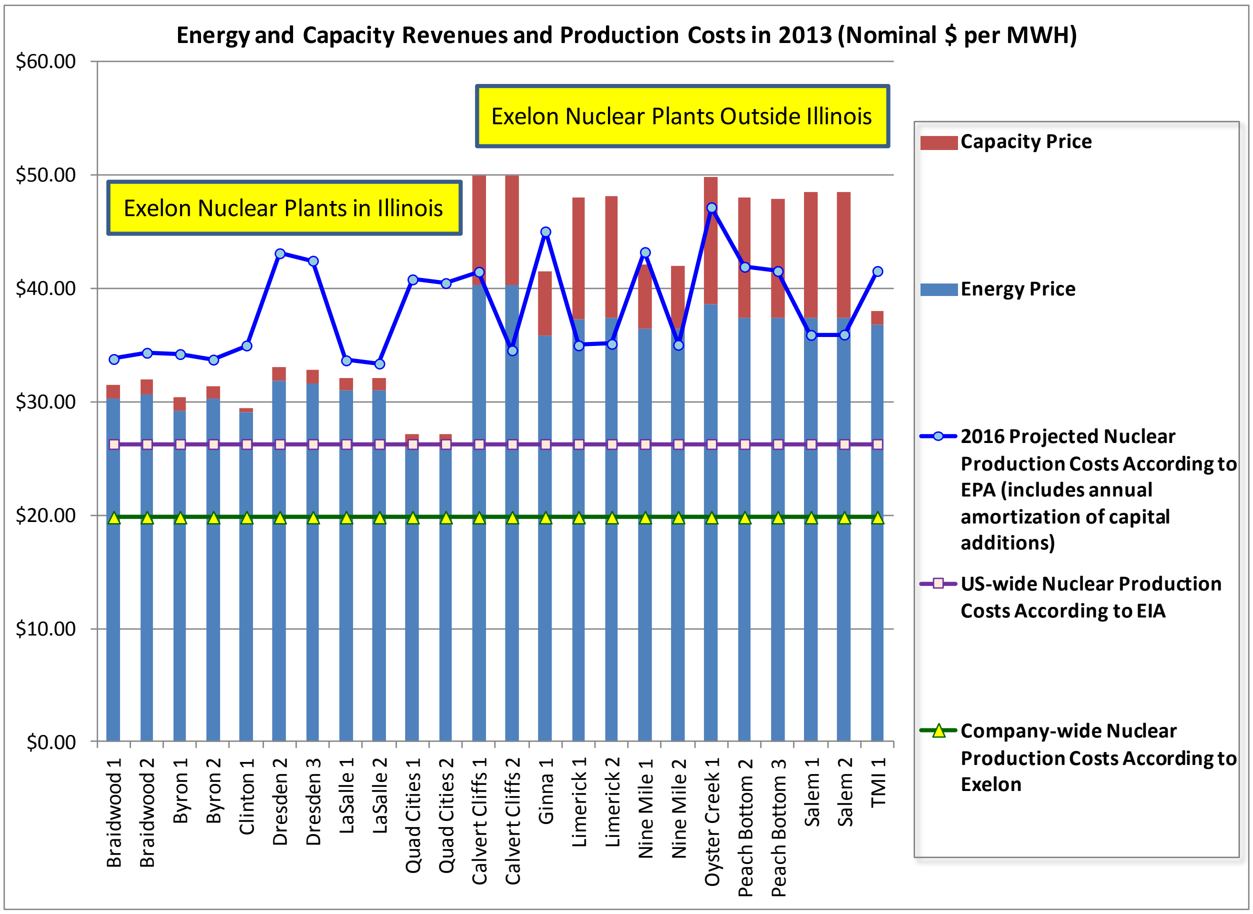
Finally, even if the cost and revenue figures presented here accurately reflect the current state of affairs, the closure of one or more of Exelon's nuclear plants would have an impact on the profitability of Exelon's other remaining plants, through the closure's impact on market prices (discussed later in this report). That is, Exelon's closure of one or more plants can increase market prices and thereby increase the revenues earned by Exelon's other plants. This means Exelon has market power. Thus, even if Exelon's least-profitable plants are at least

[36] The EPA cost projections are also higher than the cost parameters in the database used for MISO's study, discussed later in this report.

marginally profitable at the present time and expected to remain so in the future, such market power may provide Exelon with a reason to close one or more of those plants.

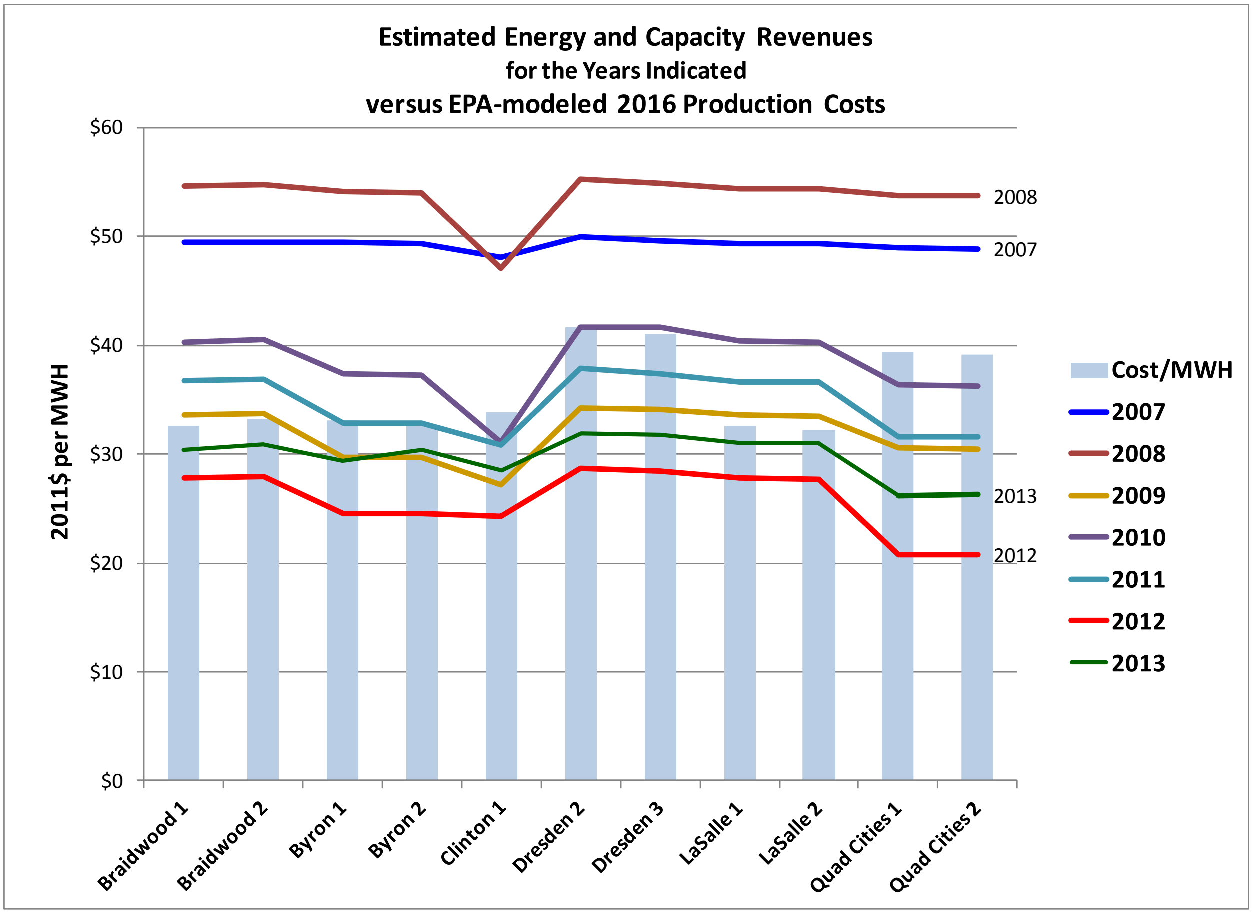
### 2013 Snapshot

The following chart compares revenues to production costs in 2013. Production costs are derived in three different ways: (1) using the nation-wide average costs according to EIA for all nuclear power plants; (2) using the Exelon-wide average production costs reported in Exelon's SEC filings; and (3) using the EPA's unit-specific projections of Exelon units' production costs for 2016 (adjusted for inflation to 2013 dollars). The chart shows that all of Exelon's nuclear plants earn revenues in excess of production costs when the 2013 production costs are equal to either the nation-wide average costs according to EIA for all nuclear power plants or the Exelon-wide average production costs reported in Exelon's SEC filings. However, if Exelon's 2013 production costs are assumed equal to the EPA's unit-specific projections for 2016, the Illinois plants' costs would have exceeded their potential revenues from energy and capacity sales.




### 2007-2013 Trend

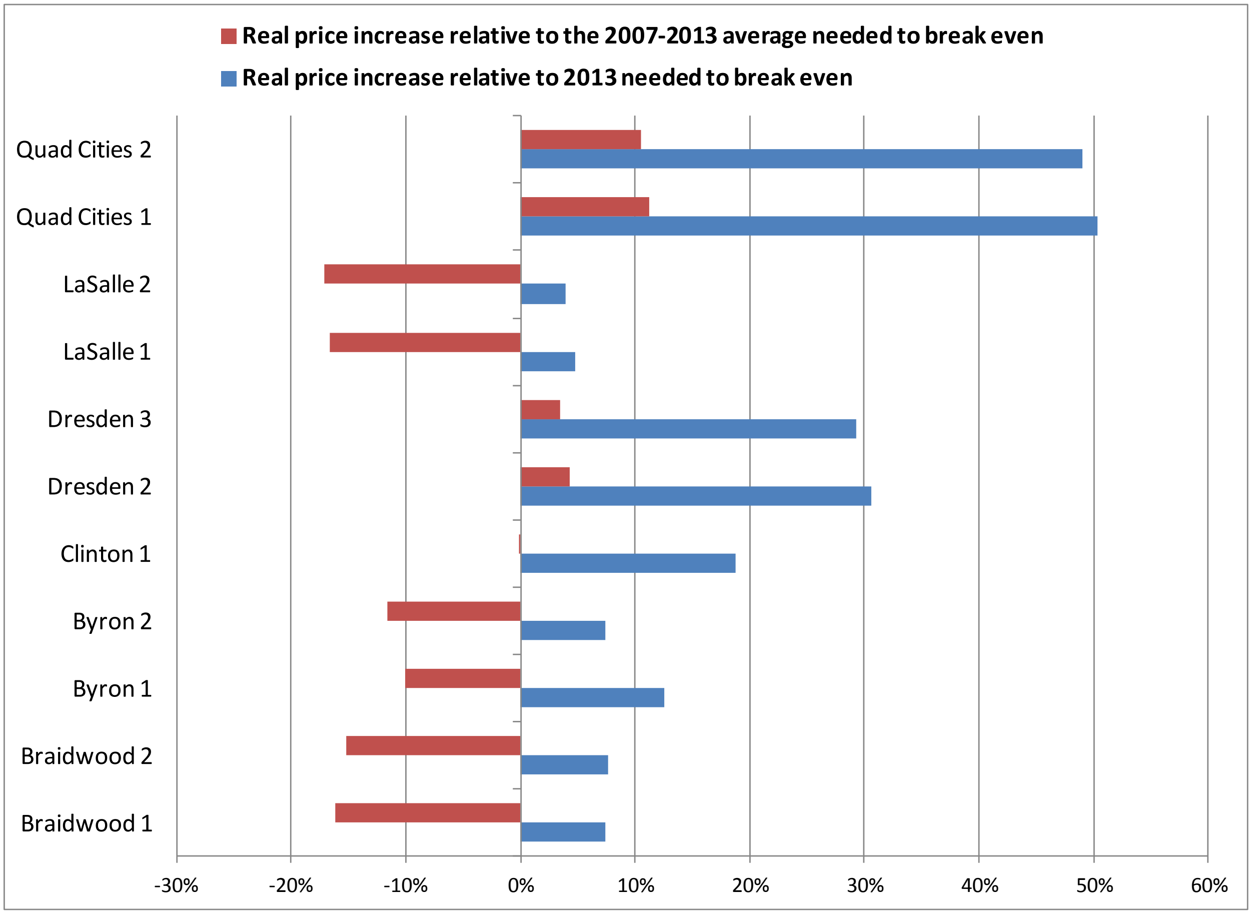
The following chart focuses on the EIA-modeled unit-specific production costs and compares those costs to energy and capacity revenues for each year between 2007 through 2013. All values are adjusted for inflation and expressed in real 2011 dollars. As shown, Illinois plants' costs would have exceeded their potential revenues from energy and capacity sales in some years but not in others.




### Price changes possibly needed to restore profitability

Because of the limited cost data available, it is not entirely clear whether or not Exelon's Illinois plants earn sufficient revenues to cover their operating costs. The provision of reliable unit-specific data would help in that determination. Nevertheless, focusing only on the higher cost parameters embedded in the EPA's-modeling, as a kind of "worst-case scenario," the following chart shows how high prices would have to rise to restore profitability in Exelon's Illinois plants. As shown, some of the Illinois nuclear units would require no price increase -- relative to the 2007-2013 price averages -- to restore profitability. However, several would. Moreover, all units would require an increase relative to the 2013 price averages. Quad Cities, for example, is the least profitable; it would require almost a 50% increase for its revenues from energy and capacity sales to exceed the EPA-modeled production costs. Again, this depends on the accuracy of the EPA's modeling of Exelon's costs, which are higher than the costs reported by the other sources reviewed by the Commission.

**Real Price Increases Required to Equal EPA-Modeled Production Costs**




### Impact of Pending Greenhouse Gas Regulations on Profitability of Existing Nuclear Power Plants

A significant reason to believe that real wholesale electricity prices will rise in the future is the advent of green-house gas ("GHG") or $CO_2$ emission regulations on new and existing fossil fuel power plants, which are currently under consideration by the EPA. Notably, nuclear power stations emit no $CO_2$ or other greenhouse gases. Thus, owners of nuclear power stations would benefit from the price increases but would not incur any of the costs of implementing the regulations. Indeed, whether the regulations result in wholesale electricity price increases or not, a least-cost plan to comply with the EPA's GHG/$CO_2$ emission rules would likely include policies to retain and possibly expand the generating capacity of Illinois' existing nuclear power stations. In one way or another, such a compliance plan would have to enable Exelon to at least cover the costs of operating those plants. Four studies were examined to gauge the price impact of such regulations: (1) EIA long-run forecasts; (2) MISO's analysis of EPA's proposal; (3) NERA Economic Consulting Inc.'s analysis of the EPA's proposal, and (4) the EPA's own analysis of the cost of complying with its proposal. They all show significant increases in prices due to new $CO_2$ reduction policies.

### EIA forecasts of the cost impact of $CO_2$ taxes

The following two charts show several EIA forecasts of the average electricity price to all consumers in the East North Central region of the nation (the region which includes Illinois, Indiana, Ohio, Michigan, and Wisconsin). Each line represents a different forecast scenario. The "Reference Case" includes no new regulations pertaining to power plant $CO_2$ emissions. Similarly, the "Accelerated nuclear retirements,"[37] "High nuclear,"[38] and "No GHG concern"[39] scenarios include no new regulations pertaining to power plant $CO_2$ emissions. Under these scenarios, the cumulative price increase over 28 years ranges between 17% and 21%. In contrast, the "GHG25" and "GHG10" scenarios assume carbon emission taxes starting in 2015 of $25 and $10 per metric ton, respectively, increasing by 5% per year through 2040. The GHG25 and GHG10 scenarios lead to cumulative price increases of 48% and 32% respectively, according to the EIA's forecasts.

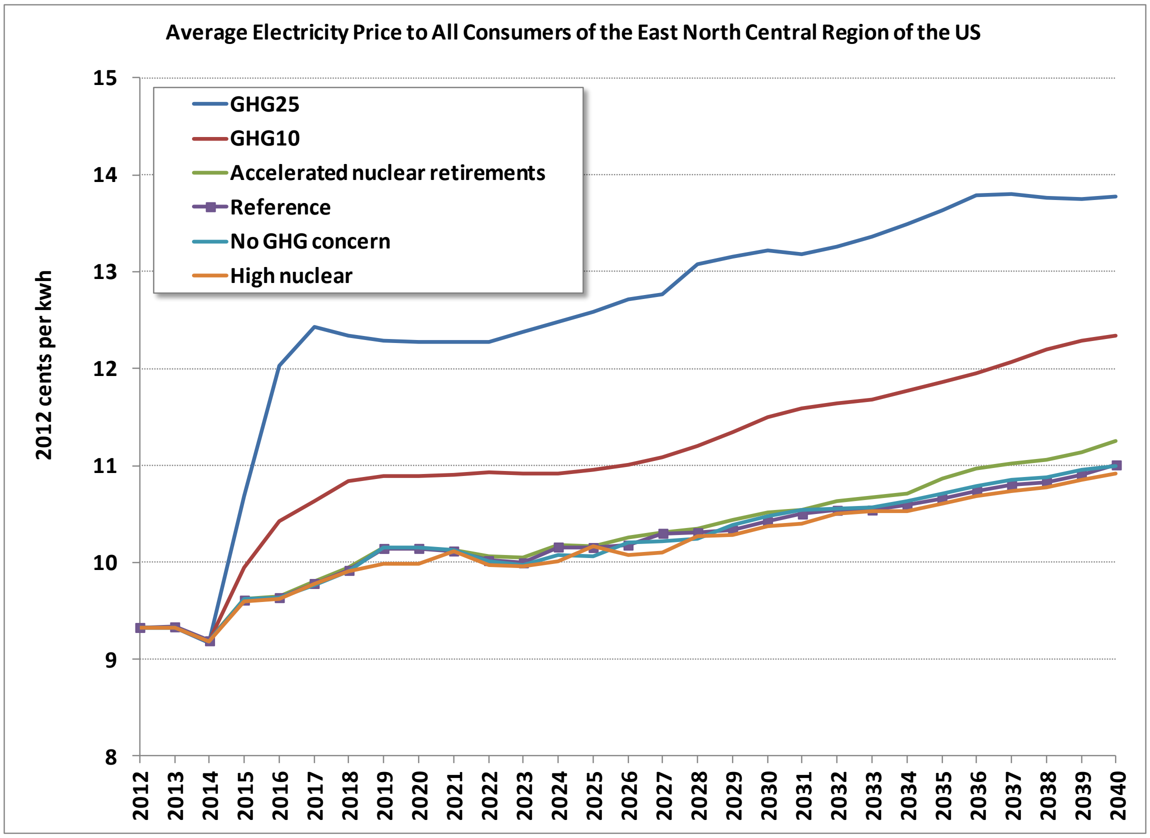
Several caveats should be noted. First, these are retail price forecasts rather than wholesale price forecasts. Also, the $CO_2$ rules currently under consideration by the EPA are not as simple as placing carbon taxes on $CO_2$ emissions. The contemplated rules provide states with considerable flexibility in devising compliance plans. Plans may be multifaceted. States may utilize, among other policy tools, programs or regulations to improve coal-fueled generation efficiency, programs or regulations to capture and sequester $CO_2$ emissions, carbon emission limits with allowance trading, energy efficiency programs, renewable energy resource programs, and retention of "at-risk" nuclear power plants. One should expect the EPA rule's impact on wholesale electricity prices to depend on the details of states' compliance plans.

---

[37] "Accelerated nuclear retirements" case assumes that all nuclear plants are limited to a 60-year life, uprates are limited to the 0.7 Gigawatts (GW) that have been reported to EIA, and no new additions beyond those planned in the Reference case. Nonfuel operating costs for existing nuclear plants are assumed to increase by 3%/year after 2013.

[38] "High Nuclear" case assumes that all nuclear plants are life-extended beyond 60 years (except for 4.8 GW of announced retirement), and a total of 6.0 GW of uprates. New plants include those under construction and plants that have a scheduled U.S. Nuclear Regulatory Commission (NRC) or Atomic Safety and Licensing Board hearing.

[39] "No GHG Concern" case assumes no GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy.



Average Electricity Price to All Consumers of the East North Central Region of the US
2012 cents per kwh
GHG25
GHG10
Accelerated nuclear retirements
Reference
No GHG concern
High nuclear
15
14
13
12
11
10
9
8
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
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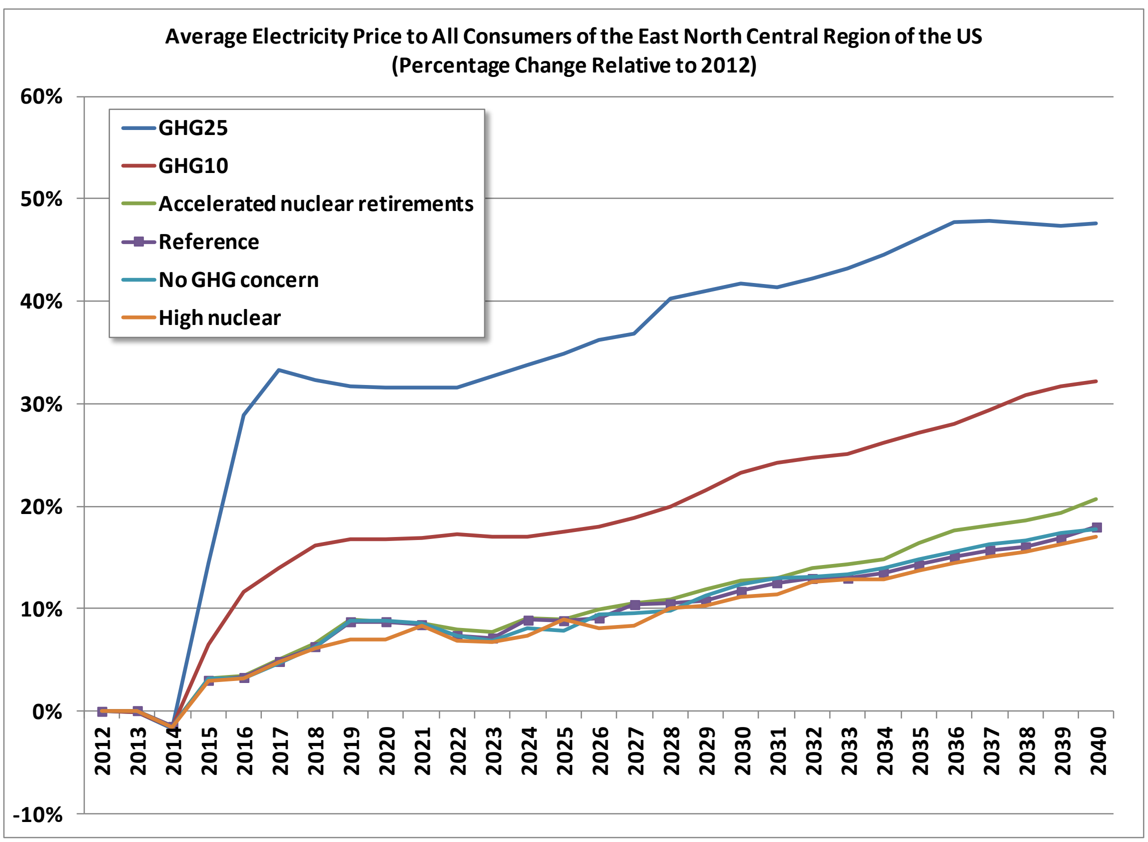

Average Electricity Price to All Consumers of the East North Central Region of the US
(Percentage Change Relative to 2012)
GHG25
GHG10
Accelerated nuclear retirements
Reference
No GHG concern
High nuclear
60%
50%
40%
30%
20%
10%
0%
-10%
2012
2013
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**MISO's analysis of the cost impact of $CO_2$ regulations**[40]

MISO's study of the impact of the EPA $CO_2$ regulations estimates potential cost increases within the MISO footprint (production costs and new fixed costs) of between 9% and 14% over the 20-year period from 2014 through 2033, relative to a business-as-usual reference case based on the draft 2015 MISO Transmission Expansion Plan. [41] According to the MISO report, the increases equate to costs of $CO_2$ avoided ranging from $38 per ton to $60 per ton.

**NERA's analysis of the cost impact of $CO_2$ regulations**[42]

NERA's study was prepared for the following organizations:

- American Coalition for Clean Coal Electricity
- American Fuel & Petrochemical Manufacturers
- Association of American Railroads
- American Farm Bureau Federation
- Electric Reliability Coordinating Council
- Consumer Energy Alliance
- National Mining Association

NERA considered three different scenarios. In the "Regional Unconstrained" scenario, compliance takes place through multi-state regional cooperation. In the "State Unconstrained" scenario, states comply by acting alone rather than regionally. In the "State Constrained" scenario, states comply by acting alone rather than regionally but they are not able to effectively utilize all four of the compliance "building blocks" that are discussed in the EPA's draft rule: (1) heat rate improvements at coal units; (2) increased utilization of existing natural gas combined cycle (NGCC) units; (3) increased utilization of renewable energy and nuclear energy resources; and (4) improvements in end-use energy efficiency. Specifically, in the State Constrained scenario, building blocks 3 and 4 are effectively unavailable.

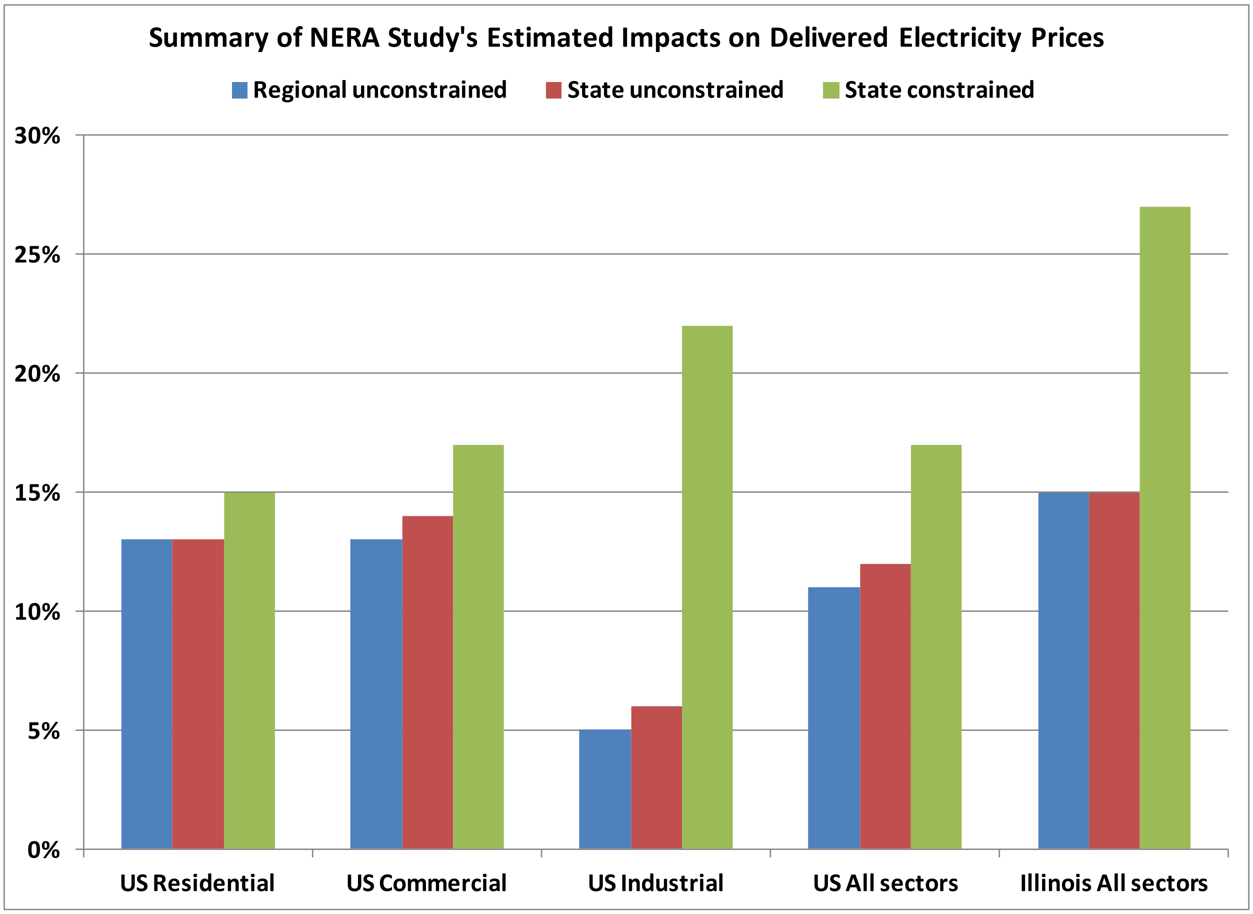
Among its findings, the study estimates that the EPA's $CO_2$ regulations would increase delivered electricity prices to all sectors within Illinois by at least 15%. This and other findings of the study are shown in the following chart.

---

[40] MISO, "Analysis of EPA's Proposal to Reduce CO2 Emissions from Existing Electric Generating Units," November 2014, available from MISO's website: https://www.misoenergy.org/Library/Repository/Communication%20Material/EPA%20Regulations/AnalysisofEPAsProposaltoReduceCO2EmissionsfromExistingElectricGeneratingUnits.pdf

[41] *Id*., pp. 3 and 12.

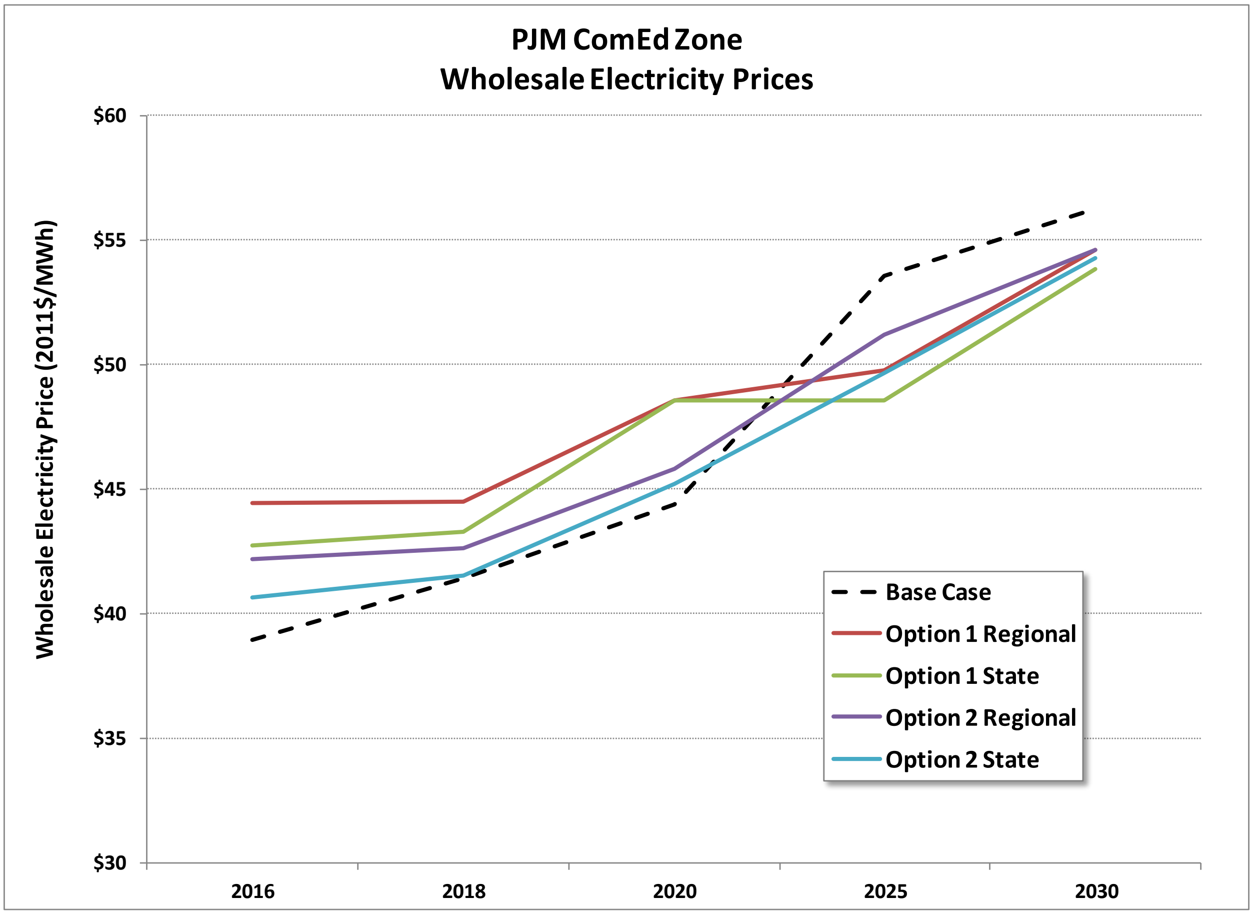
[42] NERA Economic Consulting, "Potential Energy Impacts of the EPA Proposed Clean Power Plan," October 2014, available on the NERA website: http://www.nera.com/publications/archive/2014/potential-impacts-of-the-epa-clean-power-plan.html



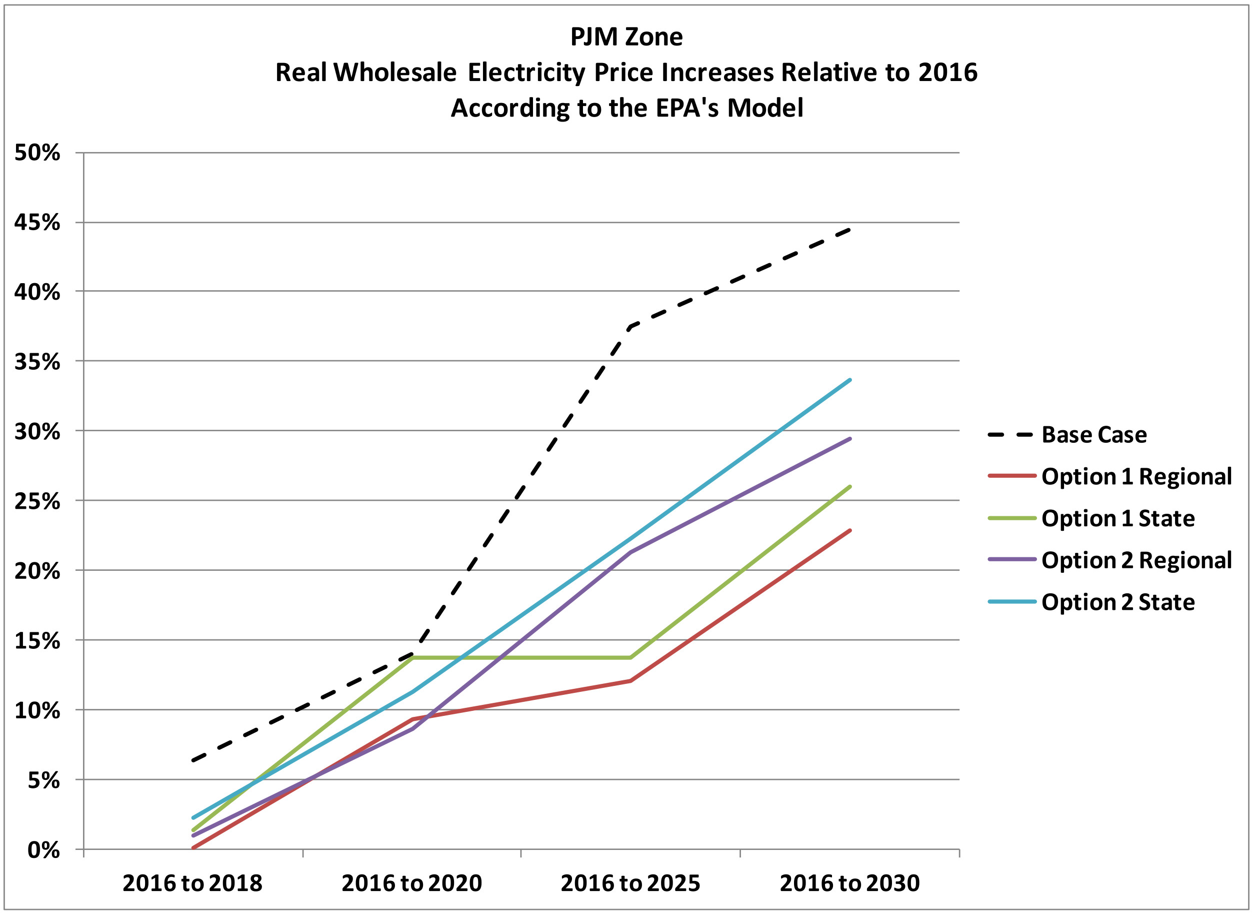

**The EPA's analysis of the cost impact of $CO_2$ regulations**

The EPA conducted its own analysis of the costs of compliance with its proposed $CO_2$ regulations. In the following chart, the "Base Case" line represents the EPA's projection of wholesale electricity prices without the rule. The other four lines represent projections of wholesale electricity prices under four different assumptions about how states achieve compliance. Even in the Base Case, it appears that EPA modelers expect PJM Zone wholesale electricity prices to rise significantly above current price levels. For instance, in 2016, the EPA model projects prices ranging from approximately \$39 to \$44 per MWH (in 2011\$), while, in 2013, actual PJM ComEd Zone wholesale energy prices were only \$30.50 per MWH and capacity prices amounted to less than \$1.22 per MWH[43] (in 2011\$).

[43] This derivation of the effective capacity price per MWH assumes an equivalent demand forced outage rate of 2% and a capacity factor of each nuclear plant no less than 93%.




The EPA's wholesale electricity price forecasts reflect substantial increases, even relative to the first year of the EPA's own projections, as shown in the following chart:




Assuming wholesale price increases of the magnitude shown above, it seems likely that eventually the profitability of Exelon's nuclear plants in Illinois would be restored.

### Impact of Other Developments on Profitability of Existing Nuclear Power Plants

#### PJM Capacity Performance Proposal

In addition to the potential for new GHG/$CO_2$ policies to increase the profitability of nuclear power stations, there are other developments underway that qualitatively may have the same impact. Proposals to enhance incentives for high unit availability and/or increase penalties for low unit availability can be expected to increase revenues for nuclear plants. In particular, PJM is currently investigating ways to reward generating units with high availability. According to an August 20, 2014 PJM Staff Proposal:

> Last winter's generator performance—when up to 22 percent of PJM capacity was unavailable due to cold weather-related problems—highlighted a potentially significant reliability issue. PJM's analysis shows that a comparable rate of generator outages in the winter of 2015/2016, coupled with extremely cold temperatures and expected coal retirements, would likely prevent PJM from meeting its peak load requirements.
>
> PJM Interconnection's capacity market has been highly successful, attracting more than 35,000 megawatts of new physical generation to the system since its inception in 2007. Our capacity auctions ensure that adequate generation is committed to serve the region three years in advance of the need. The capacity market also has eased impacts from the

> major fuel switch that is occurring as coal generators retire and new natural gas generators replace them. However, this rapid transition is contributing to concerns about the performance of the generation fleet—particularly during extremely cold weather, like last January's.
>
> PJM, therefore, is seeking to develop a more robust definition of Capacity Resources that provides stronger performance incentives and more operational availability and diversity during peak power system conditions. To do so, PJM is proposing to add an enhanced capacity product – Capacity Performance – to its capacity market structure and to reinforce the existing definition of the Annual Capacity product to ensure that the reliability of the grid will be maintained through the current industry fuel transition and beyond. [44]

On October 7, 2014, PJM issued an updated proposal, stating:

> PJM believes the transition to the more robust Capacity Performance product is necessary to improve resource performance and to set clear standards and expectations for Capacity Resources. This enhanced product definition also is necessary to articulate fuel security and operational availability standards for new resource investment, which will provide investment signals for natural gas infrastructure necessary to support reliable and flexible gas-fired generation development.
>
> Capacity Market Sellers that offer and are committed to provide the Capacity Performance product would be required to meet additional eligibility qualifications and obligations designed to ensure better performance.
>
> Under this enhanced structure, there would be two products – Capacity Performance and Base Capacity. [45]

According to a joint report by PJM and the PJM Market Monitor:

> PJM's Capacity Performance initiative will require generators to make significant investments in plant equipment, weatherization measures, better fuel procurement arrangements, expanded fuel supply infrastructure dual fuel capability and other improvements. To encourage this investment, generators must be fairly compensated, resulting in increased capacity costs, which comprised about fifteen percent of consumers' total power bills in 2013 when compared to energy costs which were about 70 percent. [46]

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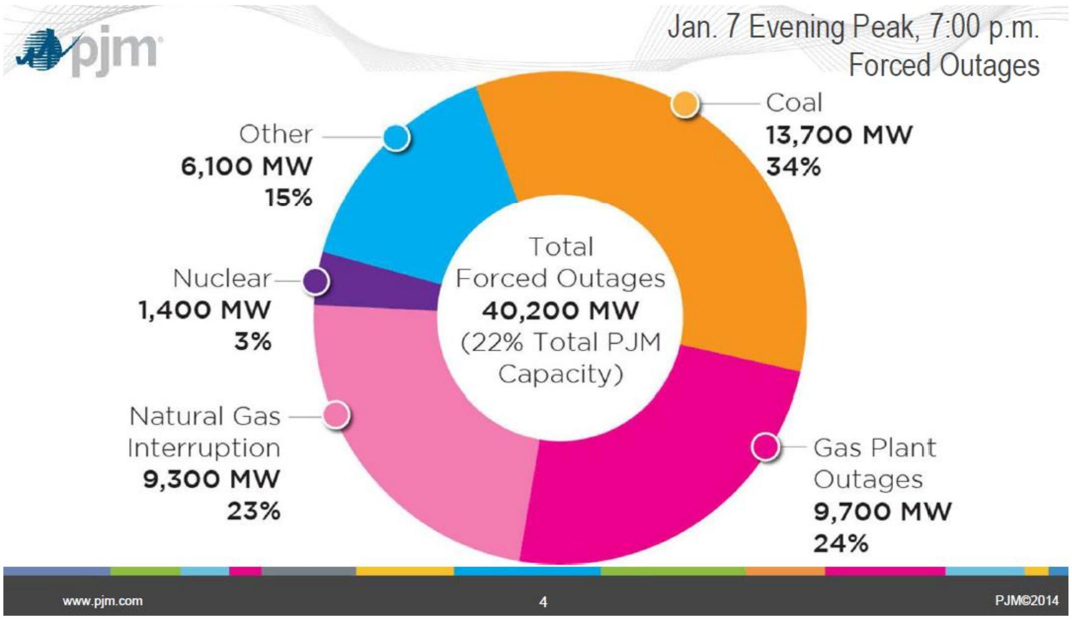
[44] "PJM Capacity Performance Proposal," PJM Staff Proposal, August 20, 2014, p. 4. Posted on the PJM website in conjunction with the 8/22/2014 Capacity Performance meeting of PJM's Markets and Reliability Committee: http://www.pjm.com/~/media/committees-groups/committees/mrc/20140822/20140822-pjm-capacity-performance-proposal.ashx

[45] "PJM Capacity Performance Updated Proposal," PJM Staff Updated Proposal, October 7, 2014, p. 4. Posted on the PJM website: http://www.pjm.com/~/media/documents/reports/20141007-pjm-capacity-performance-proposal.ashx

[46] "Capacity Performance Initiative," Andy Ott (Executive Vice President – Markets, PJM Interconnection) and Joseph Bowring (President, Monitoring Analytics), October 23, 2014, p. 2. Posted on the PJM website: http://www.pjm.com/~/media/committees-groups/committees/elc/postings/capacity-performance-cost-benefit-analysis.ashx

If adopted, a proposal such as this would benefit nuclear plant owners, not only because it would increase capacity prices, but also because nuclear plants already provide greater operational availability than other resources, as shown in the following charts.[47] The following chart[48] shows that nuclear plant outages accounted for only 3% of total outages during one of the worst times during last winter's "polar vortex," even though nuclear accounted for 18% of installed capacity. In contrast, interruption in the flow of natural gas and outages at natural gas-fired electric generating plants accounted for 47% of interruptions, even though such plants accounted for only 29% of installed generating capacity.




The following chart shows that, in recent years, nuclear plants have been among the most reliable class of generators in PJM (even without taking into consideration the experience of January 2014). Between 2006 and 2013, nuclear plants have been unavailable due to forced outrages, on average, only 2.36% of the time. Only pumped hydro peaking plants have a lower average, at 2.02%. On a monthly basis, the nuclear plants' highest forced outage rate was 7.87%, which is the lowest rate among all generator categories.

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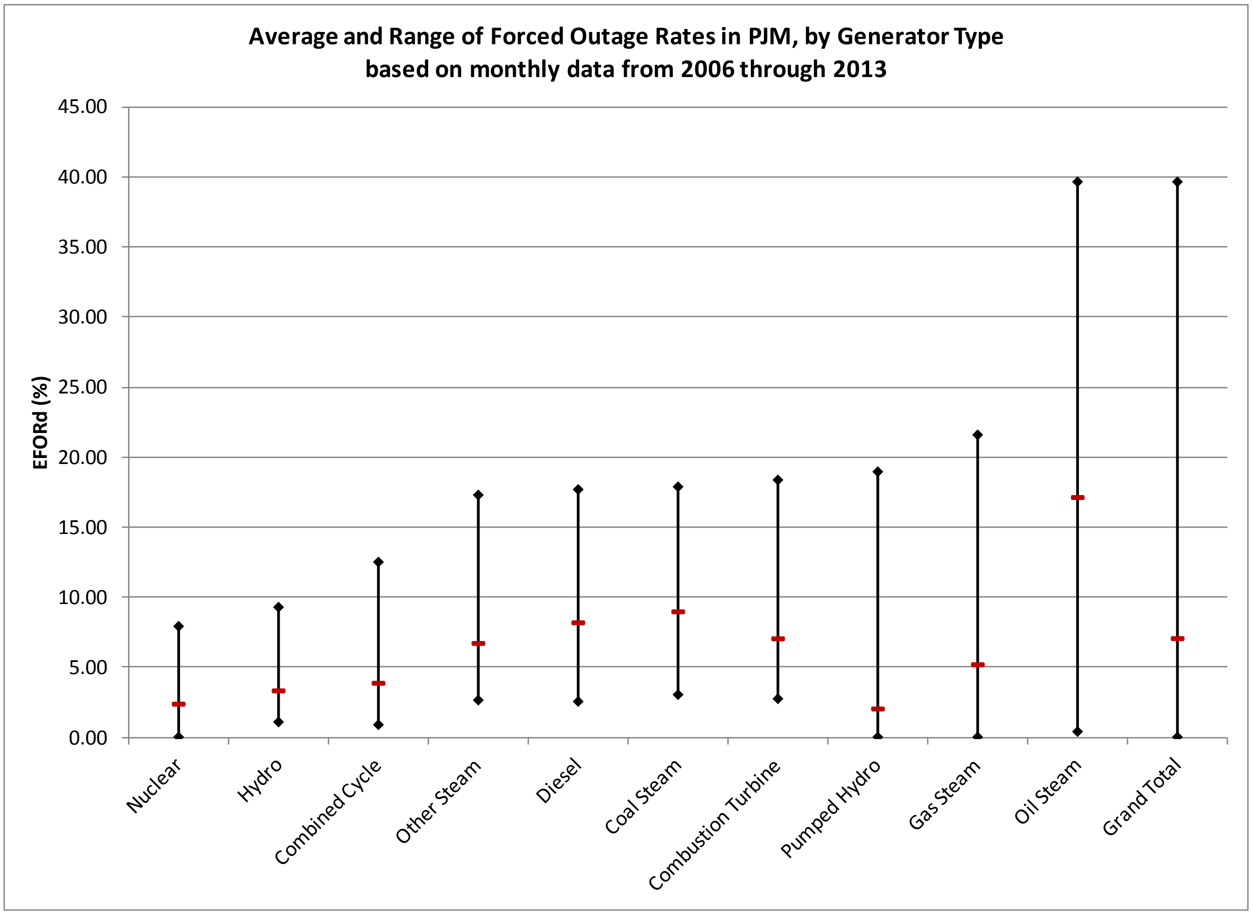
[47] PJM filed its capacity performance initiative with FERC on December 12, 2015 in FERC Docket No. ER15-623.

[48] Copied from slide 4 of "Capacity Performance," a presentation posted for the Education and Dialogue Session, August 12, 2014, of PJM's Markets and Reliability Committee, which is posted on the PJM website: http://www.pjm.com/~/media/committees-groups/committees/mrc/20140812/20140812-item-01-capacity-performance-problem-statement-presentation.ashx




**Possible Degradation in Demand Response**

Demand response refers to changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. Demand response is purchased by RTOs in a variety of ways to lower total costs. A recent court case has brought into question the ability of RTOs such as PJM and MISO to continue procuring demand response. In May, the D.C Circuit Court of Appeals vacated FERC Order 745, involving compensation levels for demand response within RTO energy markets.[49] The Court found that Order 745 constituted "direct regulation of the retail market,"[50] but that "States retain exclusive authority to regulate the retail market."[51] Since the case involved compensation in ***energy*** markets, it did not directly bar the acquisition of demand response in RTO ***capacity*** markets. Nevertheless, the Court's reasoning with respect to the FERC's lack of jurisdiction over ***retail*** electricity may be equally applicable to both energy

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[49] *Elec. Power Supply Ass'n v. F.E.R.C.*, 753 F.3d 216 (D.C. Cir. 2014). (order to vacate has been stayed pending possible further appeal)

[50] *Id.*, 225.

[51] *Id.*, 221.

***and*** capacity markets. Hence, the case may portend an eventual elimination of demand response purchases by RTOs.

In that eventuality, retail consumers and load serving entities may still be able to derive benefits from demand response measures, but the benefits likely would be less than those available if such measures continued to be coordinated and dispatched by the RTOs, at least in the short term. More to the point of this report, removing demand response from RTO capacity markets would likely result in higher capacity revenues for other capacity providers, such as Illinois' nuclear plants. In an August 2014 report, PJM's market monitor estimates that the hypothetical removal of all demand response and energy efficiency offers from PJM's 2014 capacity auction (for the 2017/2018 delivery year) would have increased the auction clearing price by 124%.[52]

Perhaps it is more likely that the role of the RTOs in demand response will be altered rather than eliminated altogether.[53] For instance, in the revised Capacity Performance proposal put forth by PJM staff on October 7, the RTO states that:

> Given the pendency and uncertainty around the D.C. Circuit Court of Appeals decision in the EPSA case, PJM proposes an alternative incorporation of demand response (DR) and Energy Efficiency (EE) into RPM. PJM continues to believe that it is critical for wholesale demand to indicate its preferences with respect to the price it is willing to pay for capacity, but above which it does not wish to purchase capacity and instead commits to limiting its consumption when PJM approaches emergency conditions. In recognition of the implications of the appellate court decision on FERC Order 745 in EPSA, PJM proposes, beginning with the May 2015 BRA for the 2018/2019 Delivery Year, to transition DR and EE to participate in RPM auctions on the demand side of the equation as opposed to the current supply side. As a consequence of transitioning from supply-side DR to demand-side DR in which demand participation is via bids indicating reductions in capacity demand, such bids must be submitted by Load Serving Entities (LSE) as the parties responsible for purchasing capacity on behalf of their retail loads.[54]

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[52] Monitoring Analytics, "The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised," August 26, 2014, p. 2. The report also includes the following caveat, at page 13:

> The results of these sensitivity analyses are also worst case, in the sense that the increases in prices and reductions in quantities cleared are the maximum levels, because they do not include any market response which would mitigate the impact on prices and cleared quantities of eliminating DR. If both these adjustments had been made prior to the 2017/2018 BRA, it is likely that additional generation resources would have entered the market, that prices would likely have been lower than the prices in these sensitivity analyses and that reliability would have been greater than in these sensitivity analyses.

[53] In PJM's Capacity Performance Filing on December 12, 2014, demand response will remain a supply resource but will have only one demand response product instead of three. The outcome of potential litigation at the U.S. Supreme Court will determine whether this scenario remains past the May 2015 PJM capacity auction.

[54] "PJM Capacity Performance Updated Proposal," op. cit., p. 15

### Certain Planned Transmission Upgrades

Planned transmission upgrades may also result in revenue increases for two of the generating stations that Exelon has expressed interest in retiring. According to ComEd, the Grand Prairie Gateway 345 kV transmission project would increase LMPs by the following amounts (per MWH) for Byron and Quad Cities:

**15-Year Generation-Weighted Average LMP Price (2018-2032)**

| | w/o GPG | w/GPG | Change |
|---|---:|---:|---:|
| Byron 1 | $43.98 | $46.19 | $2.21 |
| Byron 2 | $43.82 | $46.02 | $2.20 |
| Quad Cities 1 | $42.04 | $42.43 | $0.39 |
| Quad Cities 2 | $41.88 | $42.26 | $0.38 |

Source: ICC Docket No. 13-0657, ComEd's Response to Commissioner's Data Request 1.04, September 11, 2014.

ComEd's petition for a certificate of public convenience and necessity – a prerequisite to building the Grand Prairie Gateway project -- was granted by the ICC on October 23, 2014.

## Immediate Impacts of Nuclear Power Plant Closures on Wholesale Markets and Retail Rates

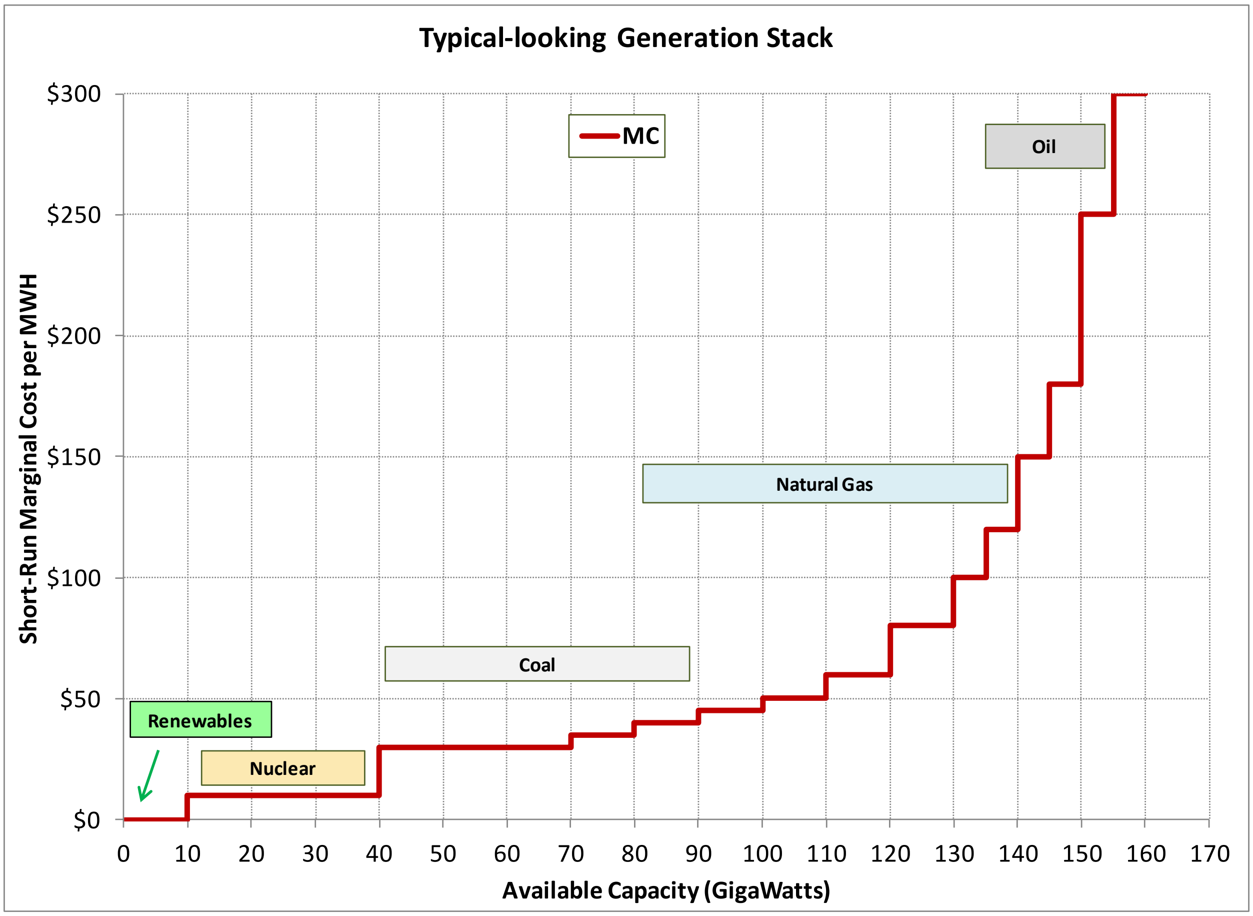
### Concepts

This section discusses the immediate impact on wholesale electricity prices and retail rates of nuclear plant closures. "Immediate" in this analysis is defined as occurring within about one year of the shutdown. All else equal, a short-run impact of any expansion or contraction in the supply of a good or service is a price decrease or increase, respectively. Electric energy is no exception.

For the most part, power plants are dispatched from least-expensive to most-expensive to operate (i.e., in "merit order"), to the extent such dispatch is consistent with existing transmission constraints. Thus, if a nuclear plant were to shut down, an RTO's short-term response would be to be to increase production at other more costly-to-operate generating facilities. Among generating units that were not operating at full capacity, the least-costly facility to operate would be selected first, to the extent to which its utilization is consistent with existing transmission constraints. If and when the least costly unit reaches its capacity limit, the next least-costly facility would be called upon. This selection process, referred to as economic dispatch, continues until there is enough supply to meet demand. The bulk electric power grid is purposefully overbuilt to maintain reliability in the face of many contingencies, such as the loss of generating capacity. However, if at some point in time the level of demand and the amount of lost nuclear capacity are high enough, and if other generating resources and transmission resources are inadequate, it is possible that emergency measures would necessitate some form of demand curtailment.

### The generation stack

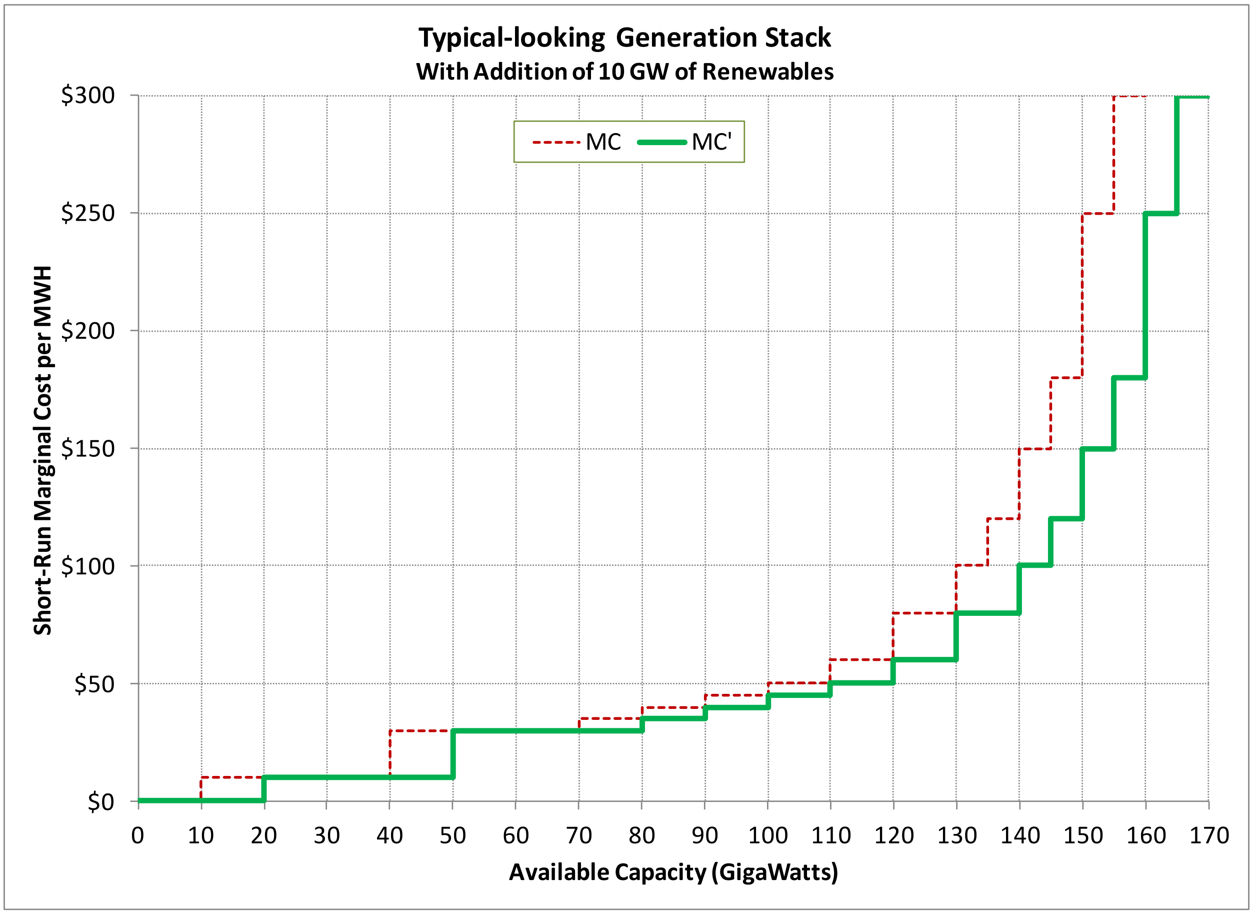
The merit order concept can be illustrated with the aid of the three diagrams, below. The first diagram is of a typical-looking "generation stack," where the supply available at a particular moment is sorted from least to most costly to operate. Moving from left to right, it shows the order in which resources are called upon to meet any given level of demand, to the extent consistent with transmission constraints. Certain renewable energy resources, such as wind and solar photovoltaic generators, are typically found at the bottom left of such diagrams, followed by nuclear, coal and natural gas, and oil-fired generators. The vertical axis shows the short-run marginal cost of operating at each level of output (roughly speaking, the added cost of delivering one additional MWH of energy onto the system). The diagrams do not show construction costs, since such costs are irrelevant to the short-run dispatch decision. They are also irrelevant to the manner in which RTOs like PJM and MISO typically determine the prices paid for electric energy.[55]




[55] The actual mechanisms used by the modern RTO to dispatch resources, determine prices and compensate resource owners are extremely complex. Thus, the descriptions provided here are simplified and intended only to convey the basic concepts.

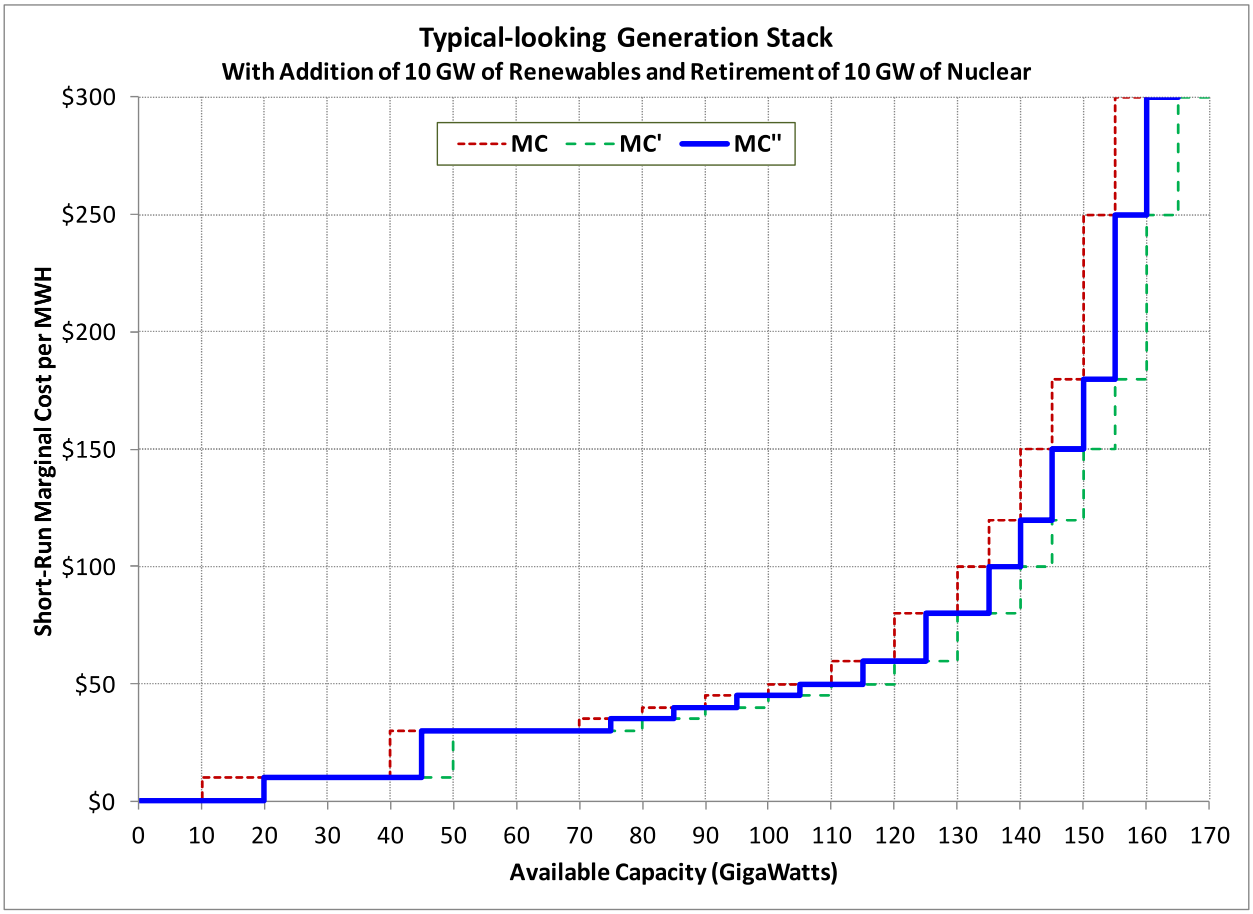
### An outward shift in supply

The next diagram depicts an expansion of renewable energy supply, which has the effect of shifting the entire stack toward the right. For any given level of power demand, the post-expansion marginal cost of serving the load (MC') is less than or equal to the original marginal cost (MC). Furthermore, prices paid to generators and by load-serving entities are largely derived from representations of marginal costs. At any point in time, prices are tied to the point where demand crosses the supply stack. Thus, the expansion of capacity has the effect of lowering marginal energy prices, or at least leaving them unchanged.




### An inward shift in supply

Finally, in the next diagram, following the expansion of renewable energy supply, there is a subsequent retirement of nuclear facilities, which shifts part of the generation stack back toward the left. For any given level of power demand, the post-contraction marginal cost of serving the load (MC'') is greater than or equal to post-expansion level (MC'), but still less than or equal to the original level (MC). In this example, the marginal prices paid for electric energy will increase.




### Base-load, Intermediate-load, Peaking-load, and Non-dispatchable Generating Units

The above diagrams may prompt one to question why anything other than the least-costly-to-operate generating resource is ever built. In general, dispatchable power plants can be categorized as base-load, peak-load, or intermediate-load. Base-load plants are generally more expensive to construct but have relatively low operating costs when operating at or near full capacity. Typically, they are relatively costly to start and stop and are relatively limited in their ability to ramp up or down quickly. They are designed with the intent of being operated on a more or less continuous basis throughout the day and throughout the year. In all these ways, nuclear units are quintessentially base-load plants.

In contrast, peaking facilities are generally less expensive to construct but have relatively high operating costs. However, they are not particularly costly to turn on and off, and they can be ramped up or down quickly. Thus, most peaking plants are used less often than most base load plants, with the bulk of their operating hours occurring during the summer months in the afternoon on-peak hours, when electricity demand is high. In all these ways, natural gas-fired combustion turbines are quintessentially peak-load plants.

Intermediate-load plants provide more operating flexibility than base-load plants but less than peaking facilities. Some natural gas and coal plants operate as intermediate-load plants. For instance, the natural gas combined cycle (NGCC) design is typically considered an intermediate-load plant. In recent years, the drop in natural gas prices (relative to coal prices), as well as increasingly stringent environmental regulations on coal plants, has spurred greater development and utilization of NGCC plants and the displacement of coal-fired generation.

In addition to the dispatchable power plants described above, there are non-dispatchable plants, such as wind turbines and solar panels, which can only be utilized intermittently, when the natural environment cooperates.[56] The operating costs of such plants are typically very low. In fact, for some such plants, production tax credits, revenues from renewable energy credit sales, and/or revenues from "above-market" priced contracts (entered into by buyers trying to comply with state-mandated renewable portfolio standards) make it possible to earn positive profits even when RTOs are paying negative prices for energy.

Because of differences in the cost structure and operating characteristics of different power plant designs, and because the level of energy demand varies significantly over time, the most cost-effective generation portfolio tends to be one that includes several different types of generating plants, including base-load, intermediate-load, peak-load, and non-dispatchable plants.

**PJM's Analysis**

To investigate the immediate impact of closing specific Illinois nuclear units, the ICC requested assistance from PJM, which has the data, modeling capabilities, and expertise to carry out such an analysis. PJM's report is attached and is summarized below.

The analysis performed by PJM utilizes a very detailed model of the grid and complex optimization algorithms to simulate the hour-by-hour operation of the grid. To examine a single year consumes approximately 24 hours of computer time per scenario. As a consequence, it was necessary to limit the analysis to only one year (2019)[57] and only five scenarios in which one to three nuclear power stations are assumed to be retired. The five scenarios examined are the retirement of:

- Clinton
- Quad Cities
- Byron
- Byron and Quad Cities
- Byron, Quad Cities, and Clinton

However, each of these five scenarios was analyzed three times: (1) assuming base-case levels of natural gas prices with base-case levels of new generation, which includes all actively-queued

[56] Actually, while resources such as wind farms traditionally have been considered non-dispatchable, many are now considered to be dispatchable over near-term time horizons, based on near-term weather forecasts and improved technology.

[57] The year 2019 was selected because: (1) it was already one of the five future years being modeled by PJM for its 2014 RTEP (the other years being 2015, 2022, 2025, and 2029); and (2) it was the first of these years for which Exelon has announced that it has nuclear units in PJM that have not been selected as capacity resources in PJM's three-year ahead capacity auction.

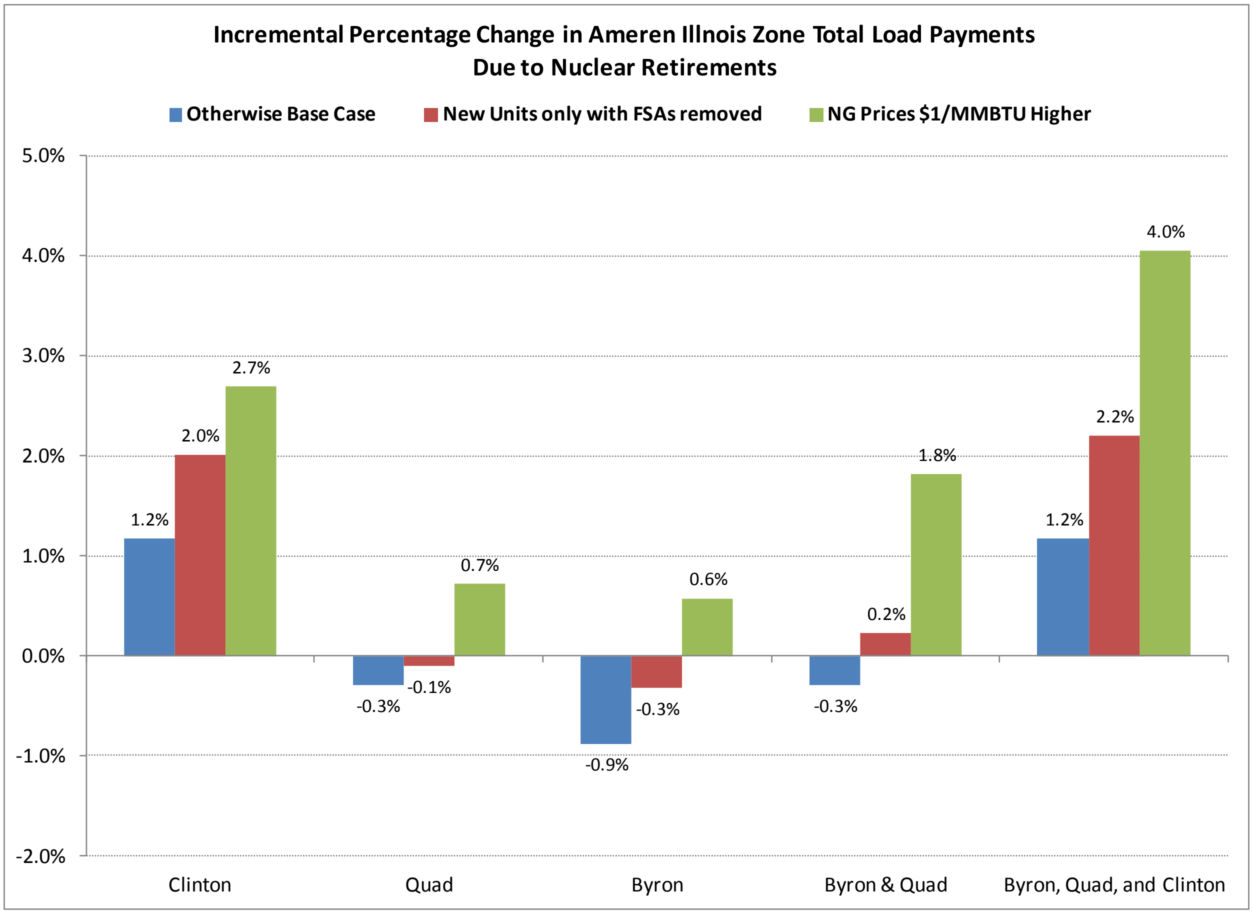
projects with executed Facilities Service Agreements (FSAs);[58] (2) assuming base-case levels of natural gas prices without any of the new generating units that only have FSAs in place; and (3) assuming higher natural gas prices and base-case levels of new generation.

Three sets of results are presented to illustrate the impact of the nuclear retirements on wholesale energy costs over 2019. In particular, PJM estimated the impact on "load payments" (derived from estimated LMPs and demand levels) in: (1) the Ameren Illinois zone of MISO; (2) the ComEd zone of PJM; and (3) the entire footprint of PJM.

**Ameren Illinois zone of MISO**

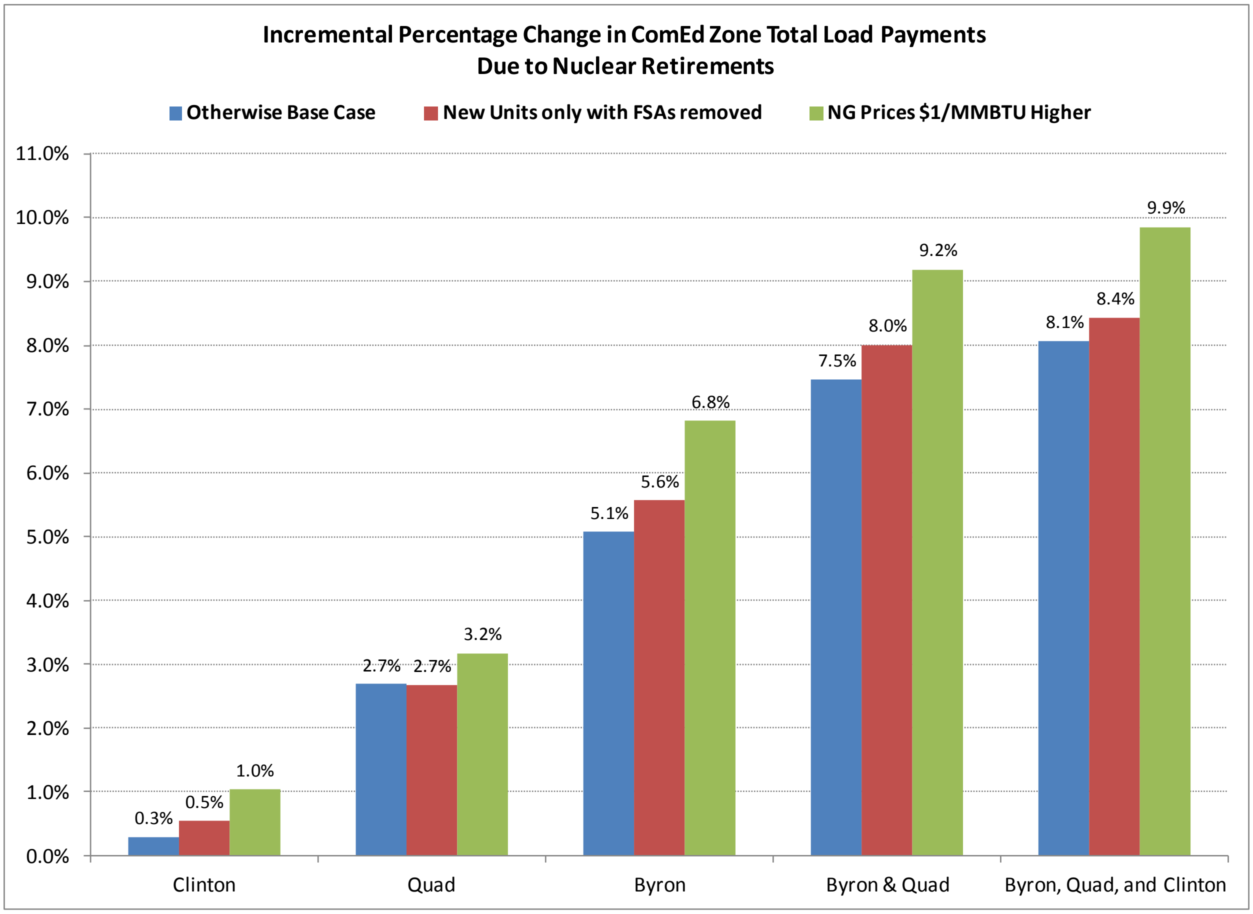
PJM found that the impact on energy costs in the Ameren Illinois zone of MISO was most pronounced when the scenario included the retirement of the Clinton nuclear power station. In that case, the load weighted average of LMPs in the MISO zone increased between 1.2% and 2.7%. Specifically, when assuming base-case levels of natural gas prices with base-case levels of new generation, the increase was 1.2%; when assuming base-case levels of natural gas prices without any of the new generating units that only have FSAs in place, the increase was 2.0%; and when assuming higher natural gas prices and base-case levels of new generation, the increase was 2.7%. In general, regardless of the area measured or the scenarios examined, the change is always the most pronounced when assuming the $1 per MMBTU higher natural gas prices, and the least pronounced when assuming base-case levels of natural gas prices with base-case levels of new generation. In scenarios where Clinton is not retired, the impact of the other retirements is not as significant. In fact, in some scenarios, under some assumptions, PJM actually predicts a decrease in Ameren zone LMPs. These and other impacts are illustrated in the following chart.

[58] A Facilities Service Agreement is a agreement between PJM and a potential resource developer to perform analyses of the impact such a resource would have upon PJM's transmission system and to identify necessary transmission infrastructure that may need to be developed to accommodate the resource. Since the potential resource developer incurs costs by entering into a FSA, the taking on of such obligations can be viewed as a measure of intent to develop.



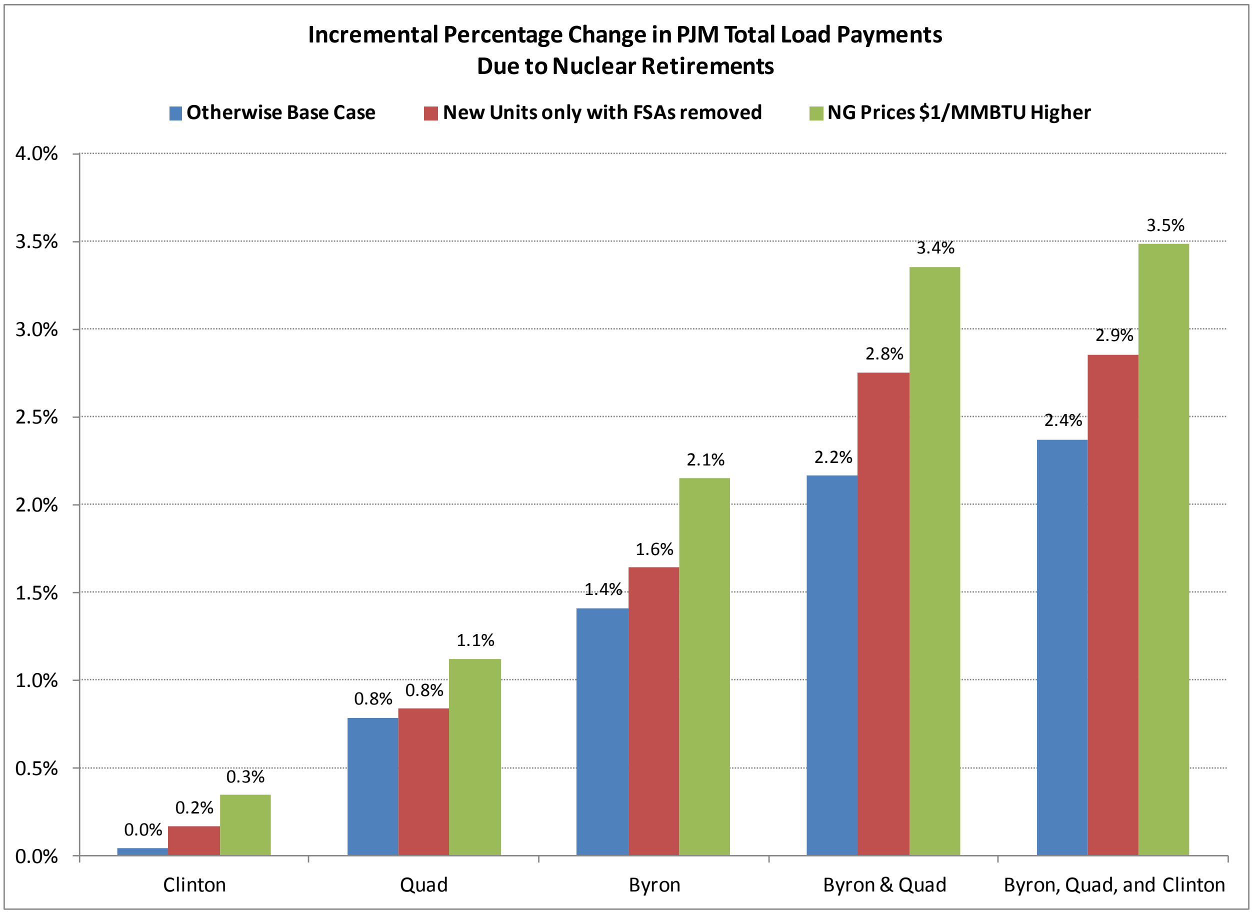

### ComEd zone of PJM

PJM found that the impact on energy costs in the ComEd Zone of PJM was least pronounced when the scenario included the retirement of the Clinton plant. However, under all scenarios, and all assumption sets examined, the retirement of any of the nuclear plants or any of the combinations led to an energy price increase. The price impact of retiring any single plant ranges from 0.3% to 6.8%. Of course, the impact is the greatest in the scenario in which Byron, Quad Cities, and Clinton are all retired. In that instance, the impact on prices are: 8.1% (assuming base-case natural gas prices and base-case levels of new generation); 8.4% (assuming base-case levels of natural gas prices without any of the new generating units that only have FSAs in place); and 9.9% (when assuming $1 per MMBTU higher gas prices). These and other impacts are illustrated in the following chart.




**Entire PJM footprint**

The impacts measured by PJM of Illinois nuclear retirements on the entire PJM footprint are less pronounced than the impact on the ComEd zone. As shown in the following chart, the impacts range from a low of 0.0% to a high of 3.5%.




**Reliability impacts**

PJM also considered the impact of the nuclear retirement scenarios on certain reliability indices.[59] According to the PJM report:

> The reliability analysis identified significant thermal and voltage violations in the transmission systems owned by ComEd, American Electric Power, American Transmission Systems Inc, Duke Energy Ohio, Duke Energy Kentucky, Northern Indiana Public Service Company, and Ameren Illinois for the various scenarios.[60]
>
> ***
>
> It would likely take substantial time to correct the violations noted above, and it is unknown if the corrections could be completed in a timely manner, i.e. prior to the

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[59] In particular, PJM subjected the scenarios to PJM load deliverability testing, generation deliverability testing, common mode outage testing, and North American Energy Reliability Corp category C3 (N-1-1) testing. These concepts are beyond the scope of this report, but are discussed within PJM's Manual 14B ("PJM Regional Transmission Planning Process"), available here: http://www.pjm.com/~/media/documents/manuals/m14b.ashx .

[60] PJM Response to Illinois Commerce Commission Request to Analyze the Impact of Various Illinois Nuclear Power Plant Retirements, PJM, October 21, 2014, p. 6.

> desired retirement of these facilities. Some corrections would require substantial construction activity and could significantly inconvenience Illinois citizens. Due to the time constraints of completing this analysis, PJM has not had an opportunity to evaluate the costs of the transmission upgrades necessary to have a reliable transmission system that would be required for each of the three scenarios. However, the costs would be significant – in the hundreds of millions of dollars or more.[61]

To put a potential cost "in the hundreds of millions of dollars or more" into perspective, in 2013, MISO and PJM approved transmission system upgrades of $1.48 billion and $7.1 billion, respectively. Also, it is important to realize that PJM's analysis does not consider how the Illinois nuclear retirements would influence investment in new generating facilities. Thus, the removal of the nuclear units in PJM's analysis, without replacement, leaves more significant voids than would be the case if new generating facilities were built in the same general area.

**Illinois Institute of Technology Analysis**

Mohammad Shahidehpour and Mark Pruitt, under the auspices of the Robert W. Galvin Center for Electricity Innovation, within the Illinois Institute of Technology, also prepared an analysis for the ICC concerning the short-run impacts of Illinois nuclear plant closures (the "IIT report"). The full report is attached.

Focusing on the calendar year 2018, the IIT report examined six scenarios:

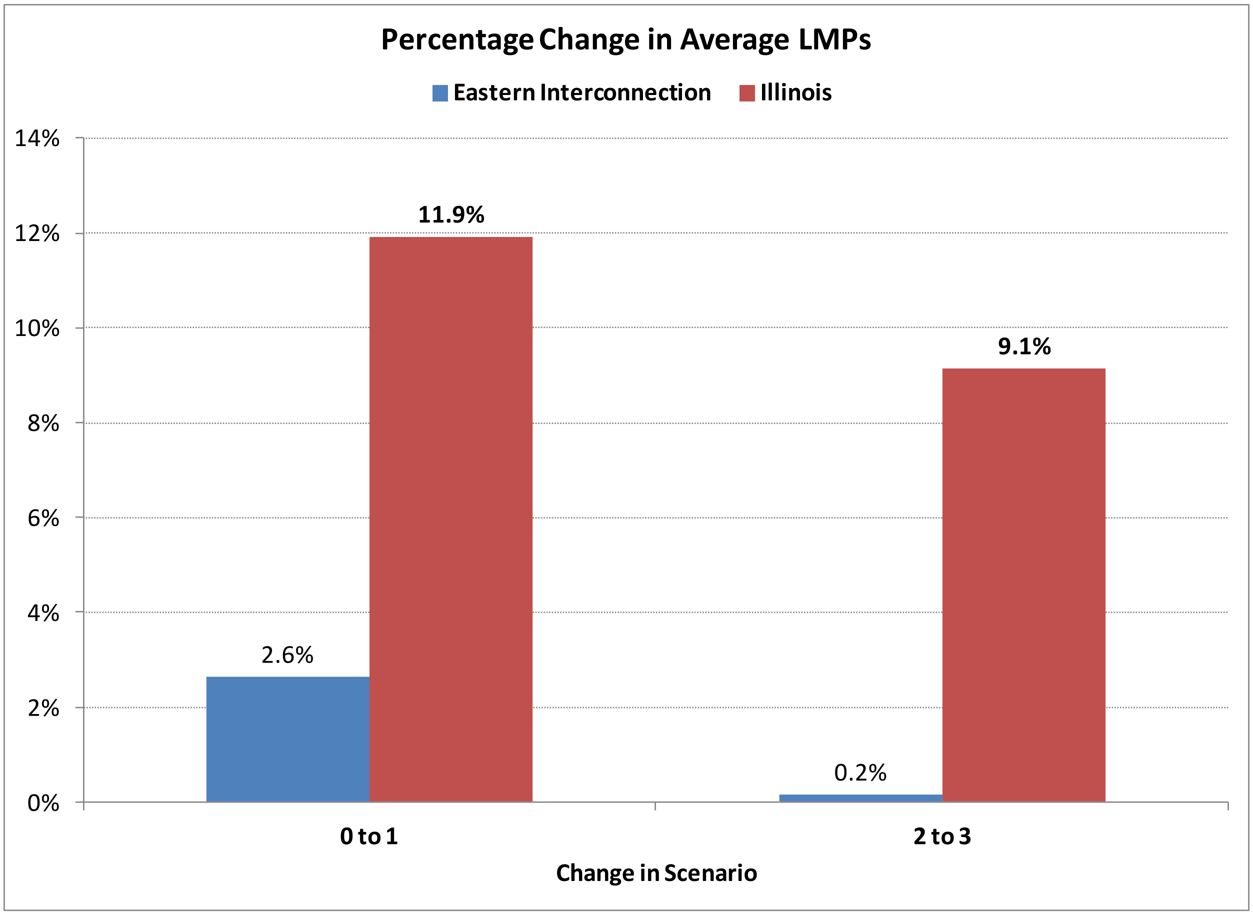
[61] *Id*., p. 7.

| No nuclear retirement scenarios | Nuclear retirement scenarios |
|---|---|
| **Scenario 0**<br>• Current EIA forward fuel price projections<br>• None of 119 planned generation units are added | **Scenario 1**<br>Same as Scenario 0, except:<br>• Byron, Quad Cities, and Clinton are closed |
| **Scenario 2**<br>Same as Scenario 0, except<br>• All 119 planned generation units are added | **Scenario 3**<br>Same as Scenario 2, except:<br>• Byron, Quad Cities, and Clinton are closed |
| | **Scenario 4**<br>Same as Scenario 3, except:<br>• Fuel price projections increased 4%<br>• Load growth increased 3%<br>• Any existing plant with a heat rate higher than 14,000 is decommissioned |
| | **Scenario 4.1**<br>Same as Scenario 4, except:<br>• Any existing plant with a heat rate higher than 14,000 is retained |

Unlike Scenarios 1 and 3, which can be compared against Scenarios 0 and 2, respectively, to isolate the impact of the nuclear retirements, Scenarios 4 and 4.1 have no similarly appropriate counterfactuals. For instance, looking at Scenario 4, there is no scenario without the nuclear plant closures that includes the higher load forecast, fuel price forecast, and decommissioning of inefficient fossil plants of Scenario 4. Therefore, this report focuses only on the first two pairs of scenarios. Among the IIT report's findings are:

- In comparing Scenario 0 to Scenario 1, the impact of the three nuclear power station retirements is projected to be an average increase in LMPs (wholesale spot energy prices) of
  - 2.6% across the entire Eastern Interconnection, and
  - 11.9% across Illinois.
- In comparing Scenario 2 to Scenario 3, the impact of the three nuclear power station retirements is projected to be an average increase in LMPs (wholesale spot energy prices) of
  - 0.2% across the entire Eastern Interconnection, and
  - 9.1% across Illinois.

These results are shown in the chart, below.




The IIT report also concluded that the impact of the three nuclear power station retirements is projected to be an average increase in load payments within Illinois of:

- 11.8%, when comparing Scenario 0 to Scenario 1, and
- 7.6%, when comparing Scenario 2 to 3.

**Monitoring Analytics Analysis**

A more limited "near worst case" analysis was also provided to the ICC by the PJM market monitor, Monitoring Analytics. In that analysis, both Byron and Quad Cities are assumed to be unavailable on a particular "hot weather alert" day in June 2014. In this case, the unavailability of the two plants leads to an average LMP increase over the PJM footprint of 16.9% and over the ComEd Zone of 26.6%.[62] In the conclusion of the analysis, Monitoring Analytics states:

> Not surprisingly, removing 4,165 MW of low cost energy from the PJM energy market would result in higher energy market prices, especially when the cost of energy from the efficient combined cycles that would likely replace them is not accounted for. Higher energy market prices would also reduce the capacity market

[62] Monitoring Analytics, Report for the Illinois Commerce Commission: Nuclear Plant Retirement Impact Preliminary Analysis of High Load Day, October 30, 2014, pp.3-4.

> offer caps of remaining units and thus capacity prices, holding everything else equal. The fact that energy market prices would increase does not support providing subsidies to these plants in order to forestall retirement. Any decision to retire the plants would be based on the basic economics of the plants. The basic economics of the plants are a function of capacity market revenue, energy market revenue and going forward costs. A careful, independent review of those economics is necessary before any conclusion could be reached about whether market revenues are adequate to continue to support the operation of the units. The information to do such a review is available to the IMM. The IMM routinely does such analyses as part of the IMM's required retirement review process as well as part of the IMM's review of capacity market offers. Such a review would also have to account for the substantial increase in capacity market revenues that is expected to result from PJM's new capacity market design proposal. If a well structured wholesale power market does not provide enough revenue to support one or both plants, then an appropriate conclusion would be that the clear market signal is to retire one or both plants.[63]

## Long-term Impacts of Nuclear Power Plant Closures on Transmission Planning, Wholesale Markets, and Retail Rates

### Concepts

The previous section discussed the *immediate* impacts of nuclear power plant closures on wholesale markets and retail rates. This section discusses the long-term impacts. In the long run, or if a nuclear power plant's closure is anticipated to occur far enough in advance, such an event would have a less dramatic impact on the energy market than it would have in the short-run if the event were unanticipated. Usually, nuclear plant closures are not sudden unheralded events. Rather they are planned and anticipated months or even years in advance.[64] This would be particularly true of a closure prompted by low power prices rather than a serious accident or the unexpected failure of plant equipment.

It is also noteworthy that generating facility owners participating in PJM's Reliability Pricing Model base capacity auctions commit to provide generating capacity three years prior to each delivery year; and the penalties for failing to actually make committed capacity available are steep.

In PJM and MISO, generators are required to provide advanced notice of unit deactivations. For instance, the PJM tariff states:

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[63] *Id*., pp. 5-6.

[64] Notable exceptions include the January 2012 shutdown of the San Onofre Nuclear Generating Station (SONGS) and the March 1979 shutdown of the Three Mile Island Nuclear Generating Station (TMI). Initially, one of the two commissioned SONGS units was shut down for routine maintenance. However, problems with both SONGS units soon became evident. Eventually, on June 7, 2013, Southern California Edison (SCE) announced that it would permanently retire SONGS Units 2 and 3; unit 1 was decommissioned in 1992. Units 2 and 3 had been in use for approximately 28 years. Unit 2 of TMI shutdown after a partial meltdown of its core. At the time of the TMI-2 accident, in 1979, TMI-1 was already offline for refueling. TMI-1 was brought back online in October 1985 and remains operational today as a part of the Exelon fleet. In 2009, TMI-1's original 40-year license was extended for another 20 years, which means it may operate until April 19, 2034.

> When a Generation Owner desires to deactivate a generating unit located in the PJM Region, such Generation Owner, or its Designated Agent, must provide notice of such proposed Deactivation in writing to the Transmission Provider no later than 90 days prior to the proposed Deactivation Date for the generating unit. This notice shall include an indication of whether the generating unit is being retired or mothballed, the desired Deactivation Date, and a good faith estimate of the amount of any project investment and the time period the generating unit would be out of service for repairs, if any, that would be required to keep the unit in, or return the unit to, operation. PJM shall promptly provide a copy of such notice to the Market Monitoring Unit.

Within 30 days of receiving such a notice, PJM will inform the Generation Owner if the deactivation would cause any reliability issues. If reliability issues are identified, the Generation Owner is given an opportunity to receive, in lieu of market-based prices, a "Deactivation Avoidable Cost Rate" plus an "Applicable Adder" (an additional 10% in the first year, up to 50% in the fourth year, above the cost-based price), as compensation for continuing to operate the generating unit while PJM identifies and implements a more permanent remedy to the reliability problem.

Similarly, MISO's tariff requires any Market Participant planning to retire or suspend all or a portion of a Generation Resource to provide notice at least twenty-six weeks prior to taking such actions. If the retirement or suspension of the generating unit creates a reliability issue, MISO shall: (1) begin negotiations of a potential System Support Resource ("SSR") Agreement with the owner or operator of the Generation Resource; and (2) use reasonable efforts to hold a stakeholder meeting to review alternatives. The list of alternatives to consider and expeditiously approve 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. A Generator alternative may be a new Generator, or an increase to existing Generator capacity.

Thus, the eventual closure of a generating facility could be accompanied by a variety of actions by the affected RTO to alleviate reliability concerns. Such actions would also have the effect of increasing the supply or availability of other generating resources or the supply of demand response resources. Such actions would moderate what might otherwise have been a sudden increase in energy market prices.

Even if notification of a generation owner's intent to close a generating facility does not trigger any reliability concerns, the closure's actual or anticipated impact on electric energy and capacity prices would provide an incentive for firms to construct replacement generating facilities. It would also lead to an increase in the cost-effectiveness of energy efficiency measures, which would justify additional investment in such measures by retail customers (as well as utilities and government agencies that are subject to mandates to subsidize such measures through energy efficiency programs). Furthermore, it would increase congestion on the transmission system, which could justify the acceleration of transmission system upgrades by RTOs like PJM and MISO. Together, such reactions would expand supply, contract demand, and allow for more efficient utilization of resources, all of which would ameliorate or even overcome the increase in prices due to the closure of the plant by itself. That is, in the long run, the closure of a particular power plant could reduce rather than increase prices, as newer more efficient faculties are introduced to the power grid.

**MISO's Analysis**

To investigate the long-run impact of closing specific Illinois nuclear units, the ICC requested assistance from MISO, which has the data, modeling capabilities, and expertise to carry out such an analysis. MISO's report is attached, and is summarized below.

In comparison to the model used by PJM for the immediate-term analysis (which was discussed in the previous section), the analysis performed by MISO utilizes a less detailed model of the grid and solves much faster (e.g., 5 minutes versus 24 hours). Also, with the model used by PJM, any and all new investment in generation and all generator retirements are exogenous inputs, while the model used by MISO endogenously solves for such changes. Because of these differences, the model used by MISO, at least in some respects, is more appropriate for investigating long-run impacts.

Another potentially important difference is that, while PJM measured the impact on "load payments" (derived from estimated LMPs and demand levels), MISO measured the impact on production costs and the fixed costs associated with new equipment. These different measures are not directly comparable, although comparability is improved somewhat in this report by expressing all impacts in percentage terms. To maintain a level of consistency with the PJM analysis (which studied only 2019), MISO was asked to assume that any nuclear plant closures would occur in 2019. However, in all other respects, MISO's analysis simulates investment and production activity over a 60-year period, beginning in 2014. There are many assumptions that go into such models; MISO's assumptions are not identical to the assumptions used by PJM.

In driving investment decisions, the simulation assumes a nominal discount rate of 8.2%, which includes a generation inflation rate of 2.5%. However, for purposes of presenting the results, MISO discounted the first twenty years of nominal costs using a nominal discount rate of 2.5% (a real discount rate of 0%, given the 2.5% level of inflation.

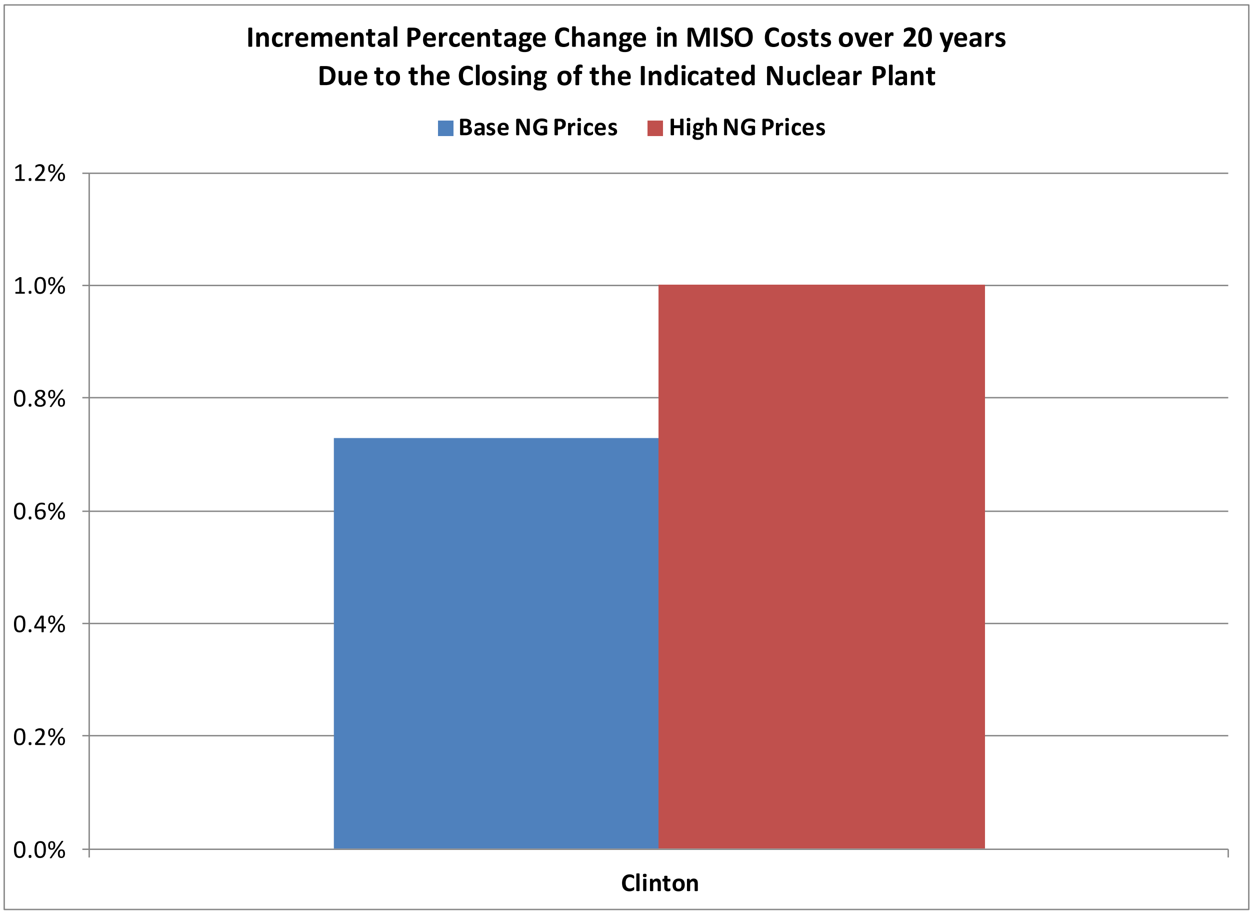
MISO analyzed six separate Illinois nuclear plant retirement scenarios:

- Clinton
- Braidwood
- Byron
- Dresden
- LaSalle
- Quad Cities

Each of these retirement scenarios was analyzed twice. First, aside from the nuclear retirements, all other input variables were set equal to the levels assumed in the 2015 MISO Transmission Expansion Plan ("MTEP") "Business as Usual" future case. Second, MISO repeated the analysis, but with natural gas prices taken from the 2015 MTEP "High Growth" future scenario.

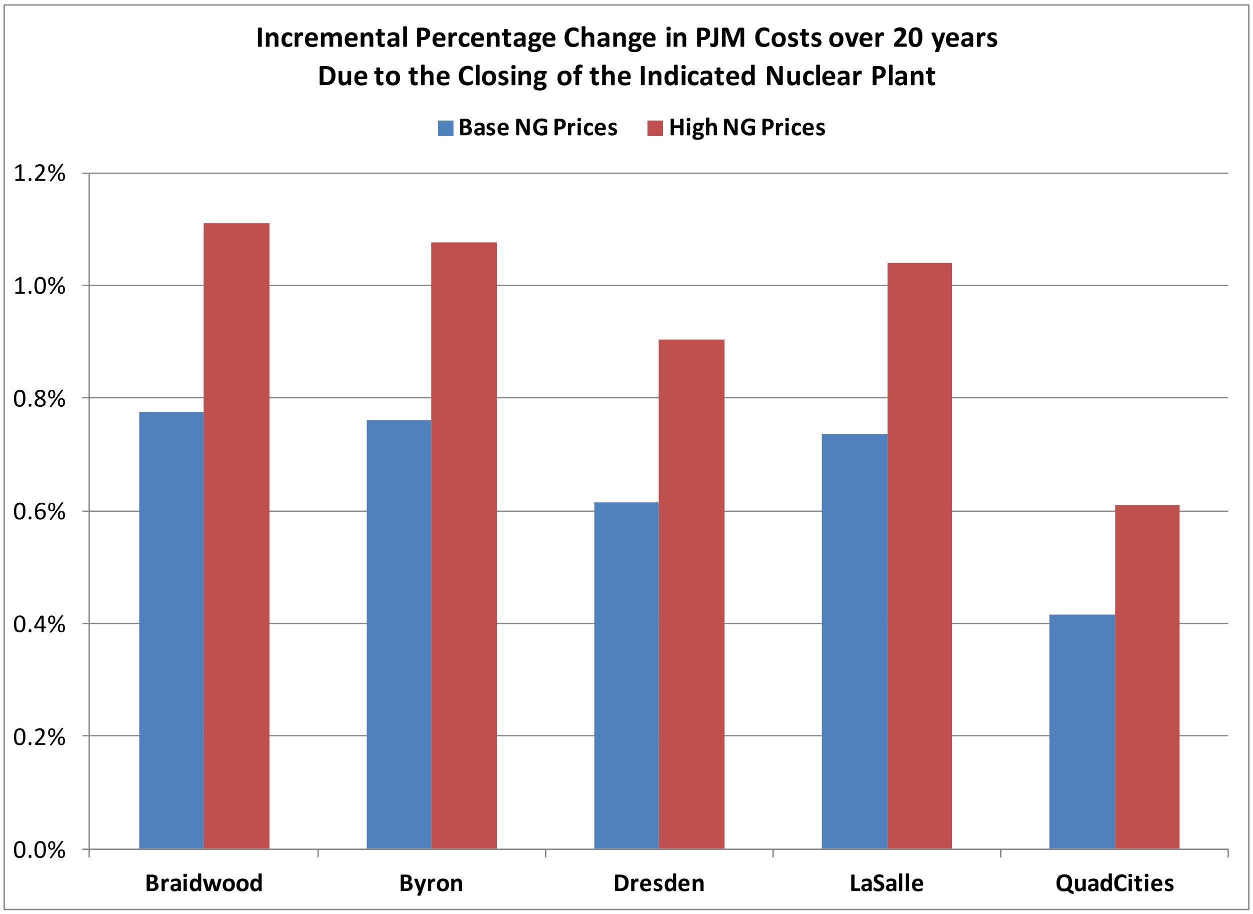
**Long-run impact on MISO of Clinton retirement**

Among MISO's findings are that retirement of the Clinton reactor would eventually lead to a replacement of that capacity with natural-gas fired plants. The present value of costs within MISO would increase by 0.7% relative to MISO's base case and by 1.0% if natural gas prices are assumed to increase at the rate specified in MISO's "High Growth Futures" planning scenario. These impacts are illustrated in the following chart. Unfortunately, MISO's analysis did not focus on the Illinois portion of MISO. It looked at the entire MISO footprint.




### Long-run impact on PJM of Braidwood, Byron, Dresden, LaSalle, or Quad Cities retirement

MISO's analysis also considered the impact of closing the nuclear power stations in the PJM portion of Illinois. Just as it has found in the case of Clinton retiring, MISO's analysis found that that retirement of each of these other nuclear power stations would eventually lead to a replacement of that capacity with natural-gas fired plants. MISO also found that the impact on the closures on the present value of PJM costs would range from 0.4% to 0.8% under the base case natural gas prices, and from 0.6% to 1.1% under the high natural gas price scenario. These impacts are illustrated in the following chart.




While MISO's analysis took a decidedly long-run view (60 years), it also produced results for individual years, including 2019, which was the focus of PJM's short-run analysis. For example, MISO found that 2019 production costs in MISO would increase by a 1.3% (assuming MISO's business-as-usual natural gas price scenario) with the closing of Quad Cities. By comparison, PJM found that if Quad Cities were closed, 2019 load payments in PJM would increase by 1.1% (assuming PJM's high gas price scenario, which is actually 14 cents per MMBTU lower than MISO's business-as-usual natural gas price scenario). However, as shown in the chart on the previous page, the long-run impact of Quad Cities closing is only a 0.4% increase in the present value of load payments in PJM. It should be stressed that comparisons such as this must be interpreted cautiously given the significant differences between the MISO and PJM methodologies, assumptions, and cost concepts.

**Potential Nuclear Power Plant Closings in Illinois**

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Reliability and Capacity

CHAPTER 2. ILLINOIS POWER AGENCY'S RESPONSE

***RESOLVED, That we urge the Illinois Power Agency to prepare a report showing how the premature closure of existing nuclear power plants in Illinois will affect reliability and capacity for the Midwest region;***

# ILLINOIS POWER AGENCY'S RESPONSE

## Potential Impacts of Nuclear Power Plant Closures in terms of the affect on reliability and capacity

### Background

This Report, prepared by the Illinois Power Agency in response to Illinois House Resolution 1146, provides a quantitative analysis of the reliability and capacity impact of the closure of at-risk nuclear plants in Illinois; and a list of possible alternatives that the State could consider to avert the premature closure of identified at-risk nuclear plants.

In preparing this report, the Agency was assisted by its procurement planning consultant, PA Consulting[65] and PA's subcontractor, the Energy Consulting Department of General Electric International ("GE"). GE used the Multi-Area Reliability Simulation ("GE-MARS") model. GE-MARS is a computer tool that is widely used within the industry to estimate resource adequacy metrics, to simulate reliability and capacity impacts.

### At Risk Nuclear Plants

There are six nuclear power plants in Illinois, representing approximately half of the electric generation output and one-quarter of the electric generating capacity in Illinois. Exelon, the owner of the six plants, has recently made statements to the effect that several of those power plants are economically challenged and that absent better tax and energy policies and a path to sustainable profits, the company will be obligated to shut down some of those plants. Byron, Quad Cities and Clinton are the nuclear power plants located in Illinois which Exelon has indicated are at risk of early retirement.[66] For purposes of this report, the three plants are therefore considered to be "at risk."

In addition to the significant portion of Illinois' electricity that they produce, nuclear power plants provide other sources of value, which may not be monetized in the commodity markets currently. Among other attributes, nuclear power plants are large reliable sources of electricity. The loss of three nuclear power plants simultaneously and suddenly could conceivably degrade service reliability in the Midwest region.

In response to concerns that several nuclear plants could be closed for economic reasons in the next several years, on May 29, 2014 the Illinois House of Representatives adopted House Resolution 1146. Illinois House Resolution 1146 ("HR 1146") resolves "[t]hat we urge the

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[65] PA Consulting Group is a leading management, systems and technology consulting firm, operating worldwide in more than 20 countries. PA draws on the knowledge and experience of approximately 2,000 people, whose skills span the initial generation of ideas and insights through to implementation. PA has over 250 consultants throughout the firm committed to supporting the energy sector, with expertise in utility performance management, due diligence, market forecasting and asset valuation, infrastructure support, and risk management and trading/procurement. PA has significant expertise in resource planning processes and in electricity market modeling issues. PA has established expertise in wholesale energy markets and is the leading consultancy in supporting asset financing and valuation in the electric generator space.

[66] Crain's article, "Exelon warns state it may close 3 nukes," http://www.chicagobusiness.com/article/20140301/ISSUE01/303019987/exelon-warns-state-it-may-close-3-nukes

Illinois Power Agency to prepare a report showing how the premature closure of existing nuclear power plants in Illinois will affect reliability and capacity for the Midwest region" (this report). HR 1146 also requests that several other agencies (the Illinois Environmental Protection Agency, the Illinois Commerce Commission, and the Illinois Department of Commerce and Economic Opportunity) provide reports on other valuable services provided by these plants, and urges that "the findings in those reports . . . include potential market-based solutions that will ensure that the premature closure of these nuclear power plants does not occur and that the dire consequences to the economy, jobs, and the environment are averted."

**Reliability and Capacity**

The Illinois Power Agency ("IPA" or "Agency") has been asked to report on "reliability and capacity." Reliability is considered as having two components: system security and resource adequacy. Resource adequacy is the attribute of reliability that is connected with and supported by the presence of generation capacity. Furthermore, the reliability of an electric grid, in terms of the adequacy of supply, can often be approximated or estimated by comparing the peak load with the amount of installed capacity (the percent difference is called Reserve Margin). This report focuses on the question of whether the closure of the three at-risk nuclear plants will adversely affect resource adequacy, and thus reliability, in the Midwest region.

The industry standard used to measure resource adequacy is the Loss of Load Expectation ("LOLE"), which is estimated using computer simulations. An annualized LOLE should be at most 0.1 (one day in ten years). This 0.1 standard is applied within PJM and Midcontinent Independent System Operator, Inc. ("MISO") to assess resource adequacy in the Midwest region. The IPA has sought to determine the effect of the premature retirements of the at-risk plants on reliability and capacity by simulating the impacts of those retirements on LOLE. If the retirements would cause LOLE to exceed 0.1, then the retirements could be said to degrade reliability.

The reliability simulation was applied to the 2018-2019 delivery year, the first year for which PJM capacity obligations have not been determined. The PJM RPM auction for the 2017-2018 delivery year has cleared at a price below the target clearing price, indicating that more than the amount of capacity required to meet the reliability standard has cleared the auction.[67] The 2018-2019 horizon was also used for MISO, both for convenience and because MISO itself has not yet issued warnings about future resource adequacy.

The IPA evaluated four scenarios or "cases." The four cases modeled are:

- **Case 1 - Base Case**: incorporates an expected state of market conditions in MISO and PJM in 2018/19 and establishes a baseline with which to compare the reliability impact of closing the at-risk nuclear plants as modeled in the three other cases;
- **Case 2 - Nuclear Retirement Case**: incorporates the same input assumptions as the Base Case with the exception that the Byron, Clinton and Quad Cities nuclear plants are modeled as retired;

[67] The target clearing price is set at 1% above the PJM IRM. IRM is the amount of capacity required to meet the 1 in 10 LOLE standard in PJM.

- **Case 3 - Polar Vortex Case**: incorporates a "Polar Vortex" extreme weather event that impacts unit availability and results in an extreme winter peak load throughout MISO and PJM for a week in a case where the at-risk nuclear plants are modeled as retired; and
- **Case 4 - High Load and Coal Retirement Case**: incorporates higher load year-round and more coal plant retirements (relative to the Base Case) for a case where the at-risk nuclear plants are modeled as retired.

The following table summarizes the four cases in each Regional Transmission Organization ("RTO"), (e.g. MISO and PJM), in terms of peak load, installed capacity and reserve margin. For cases 1, 2, and 4 the table shows summer capacity and summer load. For Case 3, because it describes a particular winter stress, the table shows winter capacity and the winter load. In addition, the cases include 14,402 MW of demand response in PJM, and 4,743 MW of demand response in MISO. Case 3 assumes that demand response is not available during the winter "polar vortex" event.

**MISO and PJM Capacity Reserve Margin Summary for 2018 – 2019 Delivery Year**[68]

| RTO | Case | Coincident Peak Load (MW) | Thermal and Hydro ICAP (MW) | Capacity Reserve Margin |
|---|---|---|---|---|
| MISO | Base Case | 129,157 | 156,540 | 22.8% |
| | Nuclear Retirement Case | 129,157 | 155,475 | 21.9% |
| | Polar Vortex Case | 104,593 | 163,408 | 35.5% |
| | High Load and Coal Retirement Case | 135,578 | 149,255 | 11.6% |
| | | | | |
| PJM | Base Case | 162,995 | 195,701 | 20.8% |
| | Nuclear Retirement Case | 162,995 | 191,582 | 18.2% |
| | Polar Vortex Case | 147,166 | 199,754 | 21.5% |
| | High Load and Coal Retirement Case | 171,353 | 184,422 | 8.3% |

The next table shows the estimated reliability index (LOLE) values for each case. It shows that resources in both RTOs are adequate in the "base case", and continue to be adequate when the at-risk nuclear plants are retired in the "nuclear retirement case". In MISO resources remain adequate if the nuclear plants are retired even if there is a "polar vortex" event, but not in the "high load and coal retirement" case. On the other hand, resource adequacy is substandard in PJM in both stress cases; but demand response mitigates the problem in the "high load and coal retirement" case. (Demand response is comprised of resources that can reduce demand during emergencies, such as interruptible load and direct control load management, and counts as capacity that can be used to maintain reliability.) Cases 3 and 4 are both extreme and would almost surely show degraded reliability even if the nuclear plants had not been modeled as retired prematurely.

[68] Wind and solar have a Nameplate MW rating of 15,240 MW in MISO and 7,796 MW in PJM in each scenario and are derated to 2,012 MW and 1,154 MW respectively.

**MISO and PJM LOLE Summary for 2018 – 2019 Delivery Year**

| RTO | Case | Coincident Peak Load (MW) | Reserve Margin (from previous table) | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) |
|---|---|---|---|---|---|
| MISO | Base Case | 129,157 | 22.8% | 0.076 | 0.004 |
| | Nuclear Retirement Case | 129,157 | 21.9% | 0.084 | 0.004 |
| | Polar Vortex Case | 104,593 | 35.5% | 0.093 | 0.013 |
| | High Load and Coal Retirement Case | 135,578 | 11.6% | 3.013 | 0.638 |
| | | | | | |
| PJM | Base Case | 162,995 | 20.8% | 0.006 | 0.000 |
| | Nuclear Retirement Case | 162,995 | 18.2% | 0.032 | 0.000 |
| | Polar Vortex Case | 147,166 | 21.5% | 0.971 | 0.939 |
| | High Load and Coal Retirement Case | 171,353 | 8.3% | 1.877 | 0.086 |

In addition, the following table shows the reliability index (LOLE) values for portions of MISO and PJM within Illinois – three MISO Local Balancing Areas and one PJM transmission zone. Resource adequacy standards are not violated in Illinois in any case, except for the "high load and coal retirement" case in PJM, and in that case the problem is mitigated by demand response. The IPA attributes the superior resource adequacy in Illinois, even given the premature closures of the nuclear plants, to its initial capacity surplus and to its robust transmission system that enables Illinois to call on out of state capacity support.

**State of Illinois Results Summary for 2018 – 2019 Delivery Year**

| RTO | LBA/ Transmission Zone | Case | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) |
|---|---|---|---|---|
| MISO | AMIL | Base Case | 0.000 | 0.000 |
| | | Nuclear Retirement Case | 0.000 | 0.000 |
| | | Polar Vortex | 0.000 | 0.000 |
| | | High Load and Coal Retirement Case | 0.002 | 0.000 |
| | | | | |
| | CWLP | Base Case | 0.000 | 0.000 |
| | | Nuclear Retirement Case | 0.000 | 0.000 |
| | | Polar Vortex | 0.000 | 0.000 |
| | | High Load and Coal Retirement Case | 0.000 | 0.000 |
| | | | | |
| | SIPC | Base Case | 0.000 | 0.000 |
| | | Nuclear Retirement Case | 0.000 | 0.000 |
| | | Polar Vortex | 0.000 | 0.000 |
| | | High Load and Coal Retirement Case | 0.007 | 0.001 |
| | | | | |
| PJM | COMED | Base Case | 0.000 | 0.000 |
| | | Nuclear Retirement Case | 0.000 | 0.000 |
| | | Polar Vortex | 0.089 | 0.002 |
| | | High Load and Coal Retirement Case | 0.159 | 0.017 |

This analysis contained in this report demonstrates that there is a potential for impacts on reliability and capacity from the premature closure of the at-risk nuclear plants. However, in many of the cases analyzed, reliability impacts remain below industry standard thresholds, and impacts appear to be more significant in other states than in Illinois. Taken alone, there may not be sufficient concern regarding reliability and capacity to warrant the institution of new Illinois-specific market-based solutions to prevent premature closure of nuclear plants. But combined with the issues raised by the Reports prepared by the ICC, IEPA, and DCEO, the totality of the impacts suggest that the General Assembly may want to consider taking measures that would prevent the premature closure of at-risk nuclear plants. The IPA notes that the impacts found have multi-state implications and policy makers should consider the implications of measures taken by Illinois alone versus regional or even national measures.

## The Illinois Power Agency and its Response to HR 1146

The Illinois Power Agency ("IPA", or "Agency") was established in 2007 by Public Act 95-0481 to ensure that ratepayers, specifically customers in service classes that have not been declared competitive and who take service from the utility's bundled rate ("eligible retail customers"),[69] benefit from retail and wholesale competition. The objective of the Act was to improve the process to procure electricity for those customers.[70] In creating the IPA, the General Assembly found that Illinois citizens should be provided "adequate, reliable, affordable, efficient, and environmentally-sustainable electric service at the lowest, total cost over time, taking into account benefits of price stability."[71] Since 2009, the IPA has successfully prepared and executed annual procurement plans to serve the electricity, energy efficiency, and renewable resources requirements of eligible retail customers of Ameren Illinois and ComEd. These procurements have harnessed the model of a competitive procurement process and the benefits of competitive markets to bring value and transparency to customers.

Nuclear power plants represent approximately half of the electric generation output, and one-quarter of the electric generating capacity in Illinois.[72] Representatives of Exelon, the owner of the six nuclear power plants operating in Illinois, have made a number of recent statements to the effect that several of those power plants are economically challenged. Illinois House Resolution 1146 ("HR 1146") urges the IPA to "prepare a report showing how the premature closure of existing nuclear power plants in Illinois will affect reliability and capacity for the Midwest region." This is one of several reports referenced in HR 1146 (reports are also requested from the Illinois Environmental Protection Agency, the Illinois Commerce Commission, and the Illinois Department of Commerce and Economic Opportunity"), which also urges that "the findings in those reports . . . include potential market-based solutions that will ensure that the premature closure of these nuclear power plants does not occur and that the dire consequences to the economy, jobs, and the environment are averted."

This report has been developed to satisfy the request made by the Illinois House of Representatives of the IPA included in HR 1146. This Report includes a quantitative analysis of the reliability and capacity impact of the closures of the nuclear plants, evaluation of key uncertainties, and actions that the State could consider to avert the premature closure of identified at-risk nuclear plants. This section explains how the report defines and analyzes "reliability and capacity" and explains which nuclear plants are considered as candidates for premature closure.

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[69] 220 ILCS 5/16-111.5(a).

[70] 20 ILCS 3855/1-5(2); 3855 /1-5(3); 3855/1-5(4).

[71] 20 ILCS 3855/1-5(1).

[72] According to the US Energy Information Administration, in each of the five years 2008-2012, Illinois nuclear power plants (all of which are owned by Exelon) accounted for 25.6% to 26.3% of the total electric power industry capability in Illinois (http://www.eia.gov/electricity/state/illinois/xls/sept10il.xls). By contrast, over those five years the annual fraction of Illinois power generation produced by the nuclear plants ranged between 47.7% and 49.2% (http://www.eia.gov/electricity/state/illinois/xls/sept05il.xls)

**At Risk Nuclear Plants**

As HR 1146 requests the IPA to address impacts from the "premature closure of existing nuclear power plants in Illinois," the Agency must first identify which "existing nuclear power plants in Illinois" may be at risk for "premature closure." For this report and the analysis contained within, the IPA considers impacts on reliability and capacity from the closures of the Byron, Quad Cities, and Clinton nuclear power plants. The reason for focusing on impacts related to the closure of these specific facilities is simple: in public statements throughout 2014, the plants' owner has characterized these three plants as at risk of shutting down.[73] For the purpose of this Report, these plants will be collectively referred to as the "at-risk nuclear plants."[74]

The first two plants are part of the PJM Interconnection ("PJM"), while the Clinton plant is part of the Midcontinent Independent System Operator, Inc. ("MISO"). The closures of the two PJM plants are considered separately from the closure of Clinton because each Regional Transmission Organization ("RTO") models and manages its own resource adequacy; there are no synergies assumed with or without the at-risk nuclear plants. In making their reliability assessments, the two RTOs assume fixed amounts of capacity support from other RTOs. The retirement of any identifiable plant in MISO would not change the support PJM assumes available. The IPA and its consultants have made the even more conservative assumption that neither RTO will obtain any resource adequacy support from the other. If MISO is not providing any reliability support to PJM in the base case, then the loss of, for example, the Clinton plant will have no deleterious effect on PJM reliability.

Additionally, the two at-risk nuclear plants located within PJM (Byron and Quad Cities) did not clear the PJM Reliability Pricing Model ("RPM") auction for the 2017-2018 delivery year. According to the plants' owner, these plants' failure to clear the RPM auction means "the market does not sufficiently recognize the significant value that nuclear plants provide in terms of reliability and environmental benefits" and "expected revenue for [those plants] will likely fall short of their anticipated costs."[75]

The third at-risk nuclear plant – the Clinton plant – is located in MISO. According to the Chicago *Tribune*,[76] it "is in the worst financial shape of the company's Illinois nuclear installations." Clinton is a single-reactor plant and therefore has to spread its capital costs over much less output than multi-unit plants. Single-unit plants are considered within the industry to be especially challenged to recover their going-forward costs in the energy market. Capacity prices in MISO have been significantly lower than in PJM (e.g., $16.75/MW-day compared to $125.99/MW-day for the 2014-2015 energy delivery year[77]) and this is a significant economic

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[73] http://www.chicagobusiness.com/article/20140301/ISSUE01/303019987/exelon-warns-state-it-may-close-3-nukes.

[74] There are nuclear plants in other states that may face similar issues, but they are outside of the scope of this Report.

[75] http://www.nei.org/News-Media/News/News-Archives/Exelon-on-the-2014-PJM-Capacity-Market-Auction.

[76] http://articles.chicagotribune.com/2014-03-09/business/ct-exelon-closing-nuclear-plants-0308-biz-20140309_1_quad-cities-plant-byron-plant-exelon.

[77] Sources: https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/AuctionResults/2014-2015%20PRA%20Summary.pdf (value for LRZ 4) and https://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2014-2015-rpm-bra-results-report-addendum.ashx (ANL value for RTO).

disadvantage to the Clinton plant. Future MISO capacity prices may rise significantly and decrease this discrepancy, but such increases are merely a possibility, not a certainty.

As background and basis for comparison, Appendix B provides information on four recent nuclear plant closures in Wisconsin, California, Vermont and New York.

**Modeling Overview**

To measure reliability impacts, this report utilizes results from the Multi-Area Reliability Simulation ("GE-MARS") model to simulate the premature retirement of three Illinois nuclear plants. To prepare this report, the model studied reliability and capacity in MISO and PJM under four scenarios. The four scenarios are:

- A base case, where at-risk nuclear plants are not taken off-line;
- A case modeling the closure of at-risk nuclear plants in Illinois, but with no other changes from the base case;
- A case modeling at-risk nuclear plant closures coupled with the impacts of a severe one-week winter weather event such as the "polar vortex" experienced in early 2014; and
- A case modeling at-risk nuclear plant closures combined with high summer electric demand and an increased level of retirement of other non-nuclear power plants relative to the base case.

To address additional uncertainty in forecasting and provide a more robust analysis, these four scenarios were modeled with and without "demand response" (the use of programs that create incentives for customers to reduce their electric consumption at critical times). The RTOs address demand response programs in their resource adequacy analyses, but the future ability of demand response to participate in RTO capacity markets has been thrown into question.[78]

Traditionally, reliability-based resource planning would primarily employ a study like the base case analyzed here. The simulation model considers and weights a variety of stress cases. In addition to the simulation of the expected impact of premature retirements over all potential outcomes, detailed analysis of individual stress cases provide insight as to whether there are specific adverse events whose effects are so great that they should be given additional weight.

The reliability modeling in this report focuses on 2018-2019, the first year for which PJM capacity obligations have not been determined. The PJM RPM auction for the 2017-2018 delivery year has cleared at a price lower than the target clearing price, indicating more than the amount of capacity required to meet the reliability standard has cleared the auction. There is most likely time to take other actions prior to a retirement effective in 2019-2020 delivery year. The 2018-2019 horizon was also used for MISO, both for convenience and because MISO itself has not yet issued warnings about future resource adequacy.

The report only analyzes a single year, and does not select additional later years. An evaluation of resource adequacy necessarily involves a project of future power plant development. Concerns about reliability expressed within the next year or two will affect

[78] The decision of the US Court of Appeals for the DC Circuit in *Electric Power Supply Association v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), has created concerns about the structure and mechanism of demand response programs. This decision may impact the future ability of RTO markets to incentivize demand response as a resource available to address high load issues, but actions by States may not be affected.

resource plans and development incentives and will tend to motivate new construction or life extensions of existing plants. The IPA and its consultants did not consider it prudent to make such assumptions at this time.

**Reliability and Capacity**

Electric reliability is the ability of the power system (which includes the nuclear power plants in Illinois that may be at risk for premature closure) to supply all demands placed upon it. Electric reliability is generally composed of two separate but related attributes: system security and resource adequacy. Roughly speaking, system security concerns operational requirements and procedures, while resource adequacy concerns resource planning.

System security is determined by the ability of the system's operating configuration to remain stable in the face of possible outages of pieces of equipment (e.g., generators or transmission circuits) or certain identified external contingencies. System security requirements assure that the electric system continues to serve load without interruption if any one identified operating piece of equipment becomes unavailable, and if certain identified pairs of pieces of equipment fail simultaneously. System security requirements also define the system's ability to respond to load fluctuation or generator intermittency.

Resource adequacy is determined by the relationships between the sizing of physical infrastructure and the nature of the needs placed upon the grid. Criteria for resource adequacy are generally expressed in terms of the amount of generating capacity that has been installed in the area under consideration, and the amount of electric energy that can securely be imported into that area when needed to meet peak demand.[79] The use of "securely" in the prior sentence demonstrates one relationship between system security and resource adequacy: system security requirements constrain the possible operating configurations of the grid, and resource adequacy means that the type, location and amount of capacity should be capable of secure operation subject to the likely load patterns across the delivery year.

This report addresses the impacts of the closures of certain specific generators on reliability, with reliability viewed as whether there will be enough physical generation in place to securely supply all demand using the area import and export constraints, as outlined in the planning reports from PJM and MISO. [80]

Resource adequacy is assessed by the two RTOs whose non-overlapping territories collectively cover Illinois, namely MISO and PJM. Each RTO models and manages its own resource adequacy.

The capacity of individual generators is denominated in megawatts ("MW"), as is system peak load. The capacity attributable to an RTO (or subdivision of the RTO) is the sum of the capacities of generators that have been dedicated to meet its peak load requirement. RTOs implement "reserve sharing" in which generators in one RTO subdivision can provide electric

[79] Capacity import and export do not mean that physical capacity is actually moved from one area to another, but that one area's ability to serve load when needed is dedicated to a different area. This dedication may be short-term – for the duration of an adverse event – or for a period of one or more years. Conceptually, resource adequacy – the capacity-related attribute of reliability – is exported from one area to another.

[80] The use of the phrase "reliability and capacity" in HR 1146 is taken to imply that the report should focus on the capacity-related attribute of reliability—namely, resource adequacy.

energy into another subdivision, when that subdivision is unable to generate enough electric energy to serve its own load. In order to support useful discussion of reliability, capacity metrics should take into account dependability as well as the timing of the demand. Resource adequacy assessments generally rely on computer simulations to estimate the probability that the system will fail to meet load. Although this report compares RTO capacity to system peak load (reserve margin) in several scenarios involving premature nuclear retirements, the report's primary analysis is based on computer simulations.

**Resource Adequacy Standards: Authorized Standard-Setters and Criteria Used**

The United States Energy Policy Act of 2005 (specifically, Section 1211 of House Resolution 6) defines the roles and jurisdiction of federal and state agencies with regard to reliability standards for the United States bulk-power system[81]. The Energy Policy Act of 2005 amended the Federal Power Act to make reliability standards[82] mandatory and enforceable.

The Federal Energy Regulatory Commission ("FERC") was given subject matter jurisdiction over the reliability of the bulk-power system under the legislation and was also given the authority to certify an Electric Reliability Organizations ("ERO"). The ERO is a single organization whose role is to develop and enforce reliability standards nationwide. It is not the same as the Regional Entities that have more localized reliability functions. And the ERO is also separate from the RTOs (e.g., MISO and PJM) that manage the transmission system. FERC certified the North American Electric Reliability Corporation ("NERC") as the ERO in the United States on July 20, 2006. Thereafter, NERC exercised its authority to delegate their responsibility of proposing and enforcing reliability standards to eight regional entities ("REs"). ReliabilityFirst Corporation ("RFC") is the RE whose jurisdiction covers all of New Jersey, Delaware, Pennsylvania, Maryland, District of Columbia, West Virginia, Ohio, and Indiana, and portions of Michigan, Wisconsin, Illinois, Kentucky, Tennessee and Virginia. RFC has developed the reliability standard utilized by MISO and PJM when reviewing resource adequacy in their service territories. All of the PJM service territory, except for the area served by Dominion Resources, and some of the MISO service territory is in the jurisdiction of RFC. The remainder of MISO is split between two other REs (the Midwest Reliability Organization and the SERC Reliability Corporation).

As of 2011, NERC measures and forecasts resource adequacy based on "assessment areas," which are not the same as RE jurisdictions. This report takes a similar approach. MISO and PJM are assessment areas. PJM and MISO conduct resource adequacy analyses for their respective areas and set target reserve margins, referred to by PJM as the Installed Reserve Margin (IRM) and by MISO as the Planning Reserve Margin (PRM).

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[81] Bulk-power system is defined as the facilities and control systems necessary for operating an interconnected electric energy transmission network and electric energy from generation facilities needed to maintain transmission system reliability. Facilities used in the local distribution of electric energy are not part of the bulk-power system.

[82] Reliability Standards are defined as a requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.

NERC/RFC Standard BAL-502-RFC-02[83] is a reliability standard that defines the criteria in the RFC region, based on achieving an annual of Loss of Load Expectation ("LOLE") of 0.1, for conducting and documenting resource adequacy analyses. Although RFC doesn't cover the entire footprint of both MISO and PJM, both organizations utilize this standard for their entire footprint. Per Standard BAL-502-RFC-02, MISO and PJM are compelled to conduct resource adequacy analyses that "calculate a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1." MISO and PJM utilize the planning reserve margins derived as part of the resource adequacy analyses to determine the reserve margin targets in their areas.

The Energy Policy Act of 2005 identified matters related to the local distribution system as falling under State jurisdiction. The legislation does not pre-empt any authority of a State to take action regarding the safety, adequacy, and reliability of electric service within the State unless the action is not consistent with a Reliability Standard. The ERO or any affected party may bring to FERC's attention a State action that potentially runs counter to a Reliability Standard at which time FERC may stay the State action pending investigation.

Therefore, States and State regulators retain the authority to oversee resource planning by regulated entities including retail electric suppliers and distribution utilities. Resource planning by the RTOs should take account of State action. The States have responsibility for reliability and resource adequacy within their individual boundaries; the RTO is responsible for resource adequacy in an integrated grid in which reserves are shared across State lines and a shortage in one State will affect reliability in other States within the RTO. As expressed in the MISO tariff,

> 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 [of the MISO Tariff] 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.[84]

### Loss of Load Expectation (LOLE)

LOLE, the electricity supply reliability standard used to measure reliability impacts in this report, is a measure of the probability of loss of load. It is defined as the average number of days in which daily peak load is expected to exceed the available capacity. The LOLE standard for MISO and PJM is 0.1 days/year, which is often stated as one day in 10 years ("1 in 10 LOLE")[85]; an expectation of greater 0.1 days/year means reliability in the electric system is below standard. 1 in 10 LOLE (numerically expressed as 0.1) is the resource adequacy criterion used for this report.

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[83] See: NERC Reliability Standards for the Bulk Electric Systems of North America, Updated October 1, 2014, pgs. 137 – 144

[84] MISO Tariff Module E-1, page 68A as effective on Nov. 19, 2013.

[85] NERC/RFC Standard BAL-502-RFC-02.

The LOLE is a probabilistic estimate and it is computed by simulation modeling. LOLE estimates reflect the likelihood that an adverse event may happen. An LOLE estimate greater than the standard of 0.1 does not imply that a reliability event will occur, just that the likelihood of such an occurrence is more likely than the standard-setting organization has determined to be desirable. By analogy: a Total Cholesterol Level ("TCL") over 240 mg/dL is considered high, and a high cholesterol level is associated with a variety of negative health impacts. If one receives a test result indicating a TCL over 240, it does not necessarily guarantee a heart attack. Instead, it indicates a strong need to take corrective actions to lower cholesterol and decrease chances of a heart attack or other serious medical condition. A variety of corrective approaches could be considered including changes in diet, additional exercise, or the use of medication.

**Reserve Margin**

Due to the complex interaction of the many variables involved in generation, transmission, and load, accurately computing the LOLE for a given system area requires specialized computer simulation models. However, a simpler and less precise way to assess reliability is to compare some measure of the total capacity of all generators on the system with the amount of generation that might be required (the annual peak load). The level of reserves is the amount by which the capacity exceeds the peak load, and resource adequacy is assured by planning to have surplus resources ("planning reserves"). The ratio of reserves to peak load is the "reserve margin":

$$\text{Reserve Margin} = \frac{\text{Capacity - Peak Load}}{\text{Peak Load}}$$

In considering RTO reserve margins, it is important to understand how the "Capacity" value in the numerator is defined. The RTO should count only "dependable" capacity or "capability", representing generators' ability to meet load when needed. The capacity figure can be reduced ("derated") in various ways in order to forecast the dependable capacity. For example, the capacity of wind generators is usually reduced to account for the timing mismatch between peak load and maximum wind turbine generation. Combustion turbines are derated to their "summer capacity". Capacity can also be derated to account for limitations or uncertainty on the ability to move power to where it will be needed; for example, MISO has limited the amount of capacity it will count from MISO-South to the load in that area at the time of the MISO peak, plus 1000 MW.[86] On the other hand, resource adequacy represents the ability of the grid to meet load, and it can be enhanced either by adding generation or by reducing load. Therefore, demand response should either be attributed capability or subtracted from the peak load.

Each RTO defines a target for its reserve margin. For MISO this is called the Planning Reserve Margin (PRM) while for PJM it is the Installed Reserve Margin (IRM). These targets are set so that when the reserve margin in the RTO's reliability simulation equals or exceeds the target, the LOLE is less than or equal to 0.1.

[86] *MISO 2014 Summer Resource Assessment*, https://www.misoenergy.org/Library/Repository/Study/Seasonal%20Assessments/2014%20Summer%20Resource%20Assessment.pdf, p. 7.

### RTO Evaluation of Retirement Requests

If the owner or operator of a power plant expresses a desire to close the plant, closure is not immediate and actions can be taken by the RTO and others to mitigate the impact of the closure on reliability and capacity. The owner or operator first must obtain approval from the RTO to close the plant. If the RTO determines there will be a deleterious effect on reliability, it has options available to forestall the closure. Other entities, such as regulators and state officials, also have options available to mitigate the impacts of a closure (short of prevention) and it may be useful to consider experiences in other states when crafting Illinois' response to any proposed early retirements.

Both MISO and PJM have procedures in place to evaluate the impact of generation retirements and suspensions of generation operations on the organizations' ability to operate the power system within applicable reliability standards. If it is found that the long-term suspension or permanent loss of a generator would result in system reliability violations and alternative solutions do not exist, the applicable organization (PJM or MISO) can require the generation to stay in-service until a solution is identified. Appendix B provides more detail about the retirement process for PJM and MISO as well as a discussion of other recent premature nuclear plant closures and how they were dealt with by the applicable RTO.

## Reliability Analysis and Summary of Findings

This section presents the reliability and capacity analysis conducted to determine the impact of the premature closure of at-risk nuclear plants. This analysis, using the GE-MARS model, concludes that the potential premature retirement of the at-risk nuclear plants will generally not degrade regional reliability in either the PJM or MISO RTO region below the relevant standard. The impacts of the potential retirements of at-risk nuclear facilities, while small, are actually most severe in outlying areas of the RTOs, in part because Illinois is a net exporter of generating capacity (and energy: in the five years from 2008-12 an annual average of 21% of Illinois' electricity production was exported out of state).[87] Substandard resource adequacy could occur in an identified stress case, although that degradation may be due to the additional stresses irrespective of the nuclear retirements.

To perform this analysis, the MISO and PJM loads and generation availability were simulated for the 2018 - 2019 delivery year. [88] As mentioned above, the IPA evaluated four scenarios or "cases." [89] The four cases modeled are:

- **Case 1 - Base Case**: incorporates an expected state of market conditions in MISO and PJM in 2018/19 and establishes a baseline with which to compare the reliability impact of closing the at-risk nuclear plants as modeled in the three other cases;

[87] Source: Derived from values in http://www.eia.gov/electricity/state/illinois/xls/sept10il.xls.

[88] June 1, 2018 to May 31, 2019.

[89] The IPA limited the number of cases to four due to time and financial constraints of the Agency.

- **Case 2 - Nuclear Retirement Case**: incorporates the same input assumptions as the Base Case with the exception that the Byron, Clinton and Quad Cities nuclear plants are modeled as retired;
- **Case 3 - Polar Vortex Case**: incorporates a "Polar Vortex" extreme weather event that impacts unit availability and results in an extreme winter peak load throughout MISO and PJM for a week in a case where the at-risk nuclear plants are modeled as retired; and
- **Case 4 - High Load and Coal Retirement Case**: incorporates higher load year-round and more coal plant retirements (relative to the Base Case) for a case where the at-risk nuclear plants are modeled as retired.

The third and fourth cases showed reliability deterioration throughout the PJM and MISO regions, but Illinois' resource adequacy was kept within the standard through the use of demand response. Case 4, the high coal retirement case, featured the largest impacts on reliability, although such impacts were heightened for areas outside of Illinois.

A detailed description of the Base Case is provided in Appendix C. Changes in input assumptions for each case relative to the Base Case are highlighted in the following table.

## Input Assumption Difference from Base Case

| Case | Input Assumption | Change from Base Case |
|---|---|---|
| 2 - Nuclear Retirement Case | Peak Hour Load & Annual Energy | No change |
| | Demand Response | No change |
| | Installed Capacity | 3 at-risk nuclear plants, representing 5,184 MW of summer capacity, are modeled as retired |
| | Unit Outage Rates | No change |
| | | |
| 3 - Polar Vortex Case | Peak Hour Load & Annual Energy | Winter load forecast increased by 8.1% in MISO[90] and 9.0% in PJM[91] for one week around the winter peak. |
| | Demand Response | Not available during week of Polar Vortex. |
| | Installed Capacity | 3 at-risk nuclear plants, representing 5,243 MW of winter capacity, are modeled as retired. |
| | Unit Outage Rates | 16% market EFOR[92] in MISO[93] and 22% market EFOR in PJM[94] for one week during Polar Vortex. |
| | | |
| 4 - High Load and Coal Retirement Case | Peak Hour Load & Annual Energy | Peak hour non-coincident load and annual energy forecast increased by 6.0% in MISO and PJM[95]. |
| | Demand Response | No change |
| | Installed Capacity | 3 at-risk nuclear plants, representing 5,184 MW of summer capacity, are modeled as retired.<br>An additional 6,221 MW and 7,160 MW of coal-fired installed capacity modeled as retired in MISO and PJM respectively[96]. |
| | Unit Outage Rates | No change |

[90] The MISO Polar Vortex winter load forecast increase is determined based on the difference between the actual peak hour load of 109,307 MW experienced during the January 2014 polar vortex and the 2013/14 winter non-coincident peak load forecast; see Appendix D.

[91] The PJM Polar Vortex winter load forecast increase is determined based on the difference between the actual peak hour load of 141,846 MW experienced during the January 2014 polar vortex and the 2013/14 winter non-coincident peak load forecast; see Appendix D.

[92] EFOR is equivalent forced outage rate, a measure of unexpected outages or part of all of a generator's capacity. See Appendix C, subsection 5 for additional information on EFOR.

[93] MISO market EFOR determined based on capacity outage rates realized during the January 2014 polar vortex as reported in MISO January 2014 Polar Vortex Analysis: Impact of Potential Generator Retirements and Natural Gas Availability (Draft), June 2014, pgs. 9-11.

[94] PJM market EFOR determined based on capacity outage rates realized during the January 2014 polar vortex as reported in *Problem Statement on PJM Capacity Performance Definition, PJM Staff Draft Problem Statement, August 1, 2014, pgs. 6-8.*

[95] Peak hour load and annual energy increases for both MISO and PJM are based on the increase in PJM high (90/10) peak hour load forecast relative to the summer peak load forecast; see Appendix D.

[96] The specific additional coal plant retirements are based on GE's proprietary list of coal plants that could potentially be impacted by future market conditions but whose owners have not indicated an intention to retire these generators.

The next table summarizes the capacity balance (relationship of load and installed capacity, Capacity Reserve Margin) for the four scenarios, in each of PJM and MISO. The capacity figures in this table are installed capacity ("ICAP"). Derations for thermal and wind/solar capacity are usually quite different, which is why they are shown separately. The High Load and Coal Retirement Case shows a greater impact on Capacity Reserve margin than premature nuclear retirement by itself. This can be seen in the impacts of each case on thermal ICAP (generation of electricity from heat energy whether from combustion, geothermal heat or nuclear fission) and hydroelectric (including pumped storage) ICAP (note that the figure for Polar Vortex is for winter peak ICAP).

Notes about Case 3: The last column of following table implies that there is ample capacity present in the polar vortex case (Case 3), at least in the winter. The thermal and hydroelectric ICAP shown in that table is, appropriately, the winter capacity, which is generally higher than the summer value shown for the other cases. At the same time, the coincident peak load shown in that table is the winter coincident peak, which even in the extreme case of 2014, was well below the summer peak. The stresses on the system during the 2014 polar vortex event were not due to shortages of physical capacity, but rather due to the inoperability of that capacity and lack of response of demand response resources when called. This is represented in the GE-MARS model as increased outage rates and unavailable demand response resources. (Demand response is comprised of resources that can reduce demand during emergencies, such as interruptible load and direct control load management, and counts as capacity that can be used to maintain reliability.) Even so, the study results for Case 3 indicate capacity reserve margins that appear quite adequate. This demonstrates a deficiency of using capacity as an indicator of reliability.

In this table ICAP represent the maximum rate at which energy can be produced from equipment in place; wind and solar capacity is "derated" to account for meteorological conditions. "Coincident peak load" measures the maximum simultaneous electric demand in the area for the given season – the summer coincident peak load is also the annual maximum.

**MISO and PJM Capacity Reserve Margin Summary for 2018 – 2019 Delivery Year**[97]

| RTO | Case | Coincident Peak Load (MW)[98] | Thermal and Hydro ICAP (MW)[99] | Capacity Reserve Margin[100] |
|---|---|---|---|---|
| MISO | Base Case | 129,157 | 156,540 | 22.8% |
| | Nuclear Retirement Case | 129,157 | 155,475 | 21.9% |
| | Polar Vortex Case | 104,593 | 163,408 | 35.5% |
| | High Load and Coal Retirement Case | 135,578 | 149,255 | 11.6% |
| | | | | |
| PJM | Base Case | 162,995 | 195,701 | 20.8% |
| | Nuclear Retirement Case | 162,995 | 191,582 | 18.2% |
| | Polar Vortex Case | 147,166 | 199,754 | 21.5% |
| | High Load and Coal Retirement Case | 171,353 | 184,422 | 8.3% |

GE-MARS was used to measure resource adequacy, expressed as LOLE, under each case to gauge the impact of changing market conditions on reliability in both MISO and PJM. LOLE is measured at the RTO level and within each Local Balancing Area ("LBA")[101] in MISO and transmission zone in PJM. In MISO and PJM there are 39 LBAs and 22 transmission zones, respectively, for which LOLE is measured. The LBAs in MISO represent sub-regions within the 9 Local Resource Zones[102] ("LRZs") that MISO considers in its LOLE analysis. Appendix G provides a full definition and maps of the LRZs and LBAs, while Appendix H provides a full definition and a map of the PJM zones.

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[97] Wind and solar have a Nameplate MW rating of 15,240 MW in MISO and 7,796 MW in PJM in each scenario and are derated to 2,012 MW and 1,154 MW respectively.

[98] Summer coincident peak hour load reported for the Base Case, Nuclear Retirement Case and High Load and Coal Retirement Case. Winter coincident peak hour load reported for the Polar Vortex Case.

[99] Summer thermal ICAP reported for the Base Case, Nuclear Retirement Case and High Load and Coal Retirement Case. Winter thermal ICAP reported for the Polar Vortex Case.

[100] Reserve Margin is the amount by which Thermal ICAP plus Wind and Solar Capability (Derated) exceeds the Coincident Peak Load, divided by Coincident Peak Load. In the Polar Vortex Case, Thermal ICAP values are derated as described in the text.

[101] Local Balancing Authority is a MISO term referring to the former utility balancing authorities that now reside in MISO. An LBA is an operational entity, typically a utility, which is responsible for compliance to NERC for the subset of NERC balancing authority Reliability Standards for their local area.

[102] LRZ is a geographic area within MISO intended to address congestion that limits the deliverability of resources when considering reliability.

The next table shows the simulated LOLE for the four scenarios, in each of PJM and MISO.[103] RTO-wide resources are projected to be adequate in MISO and PJM (i.e., LOLE was calculated to be less than or equal to 0.1, the target reliability standard) in each case except the High Load and Coal Retirement Case in MISO and the Polar Vortex Case in PJM.

**MISO and PJM LOLE Summary for 2018 – 2019 Delivery Year**

| RTO | Case | Coincident Peak Load (MW)[104] | Reserve Margin (from previous table) | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) |
|---|---|---|---|---|---|
| MISO | Base Case | 129,157 | 22.8% | 0.076 | 0.004 |
| | Nuclear Retirement Case | 129,157 | 21.9% | 0.084 | 0.004 |
| | Polar Vortex Case | 104,593 | 35.5% | 0.093 | 0.013 |
| | High Load and Coal Retirement Case | 135,578 | 11.6% | 3.013 | 0.638 |
| | | | | | |
| PJM | Base Case | 162,995 | 20.8% | 0.006 | 0.000 |
| | Nuclear Retirement Case | 162,995 | 18.2% | 0.032 | 0.000 |
| | Polar Vortex Case | 147,166 | 21.5% | 0.971 | 0.939 |
| | High Load and Coal Retirement Case | 171,353 | 8.3% | 1.877 | 0.086 |

The portion of Illinois that is in MISO is comprised of 3 LBAs: Ameren Illinois ("AMIL"), City Water Light & Power ("CWLP"), and Southern Illinois Power Cooperative ("SIPC"). The portion of Illinois that is in PJM is comprised of one transmission zone, Commonwealth Edison ("ComEd"). As shown in below, resources are adequate in Illinois in each case, when accounting for demand response.

[103] LOLE is shown with and without the use of demand response resources to understand whether those demand resources might be required and are sufficient to avoid outages. The NERC/RFC Reliability Standards include demand response resources in their determination of LOLE.

[104] Summer coincident peak hour load reported for the Base Case, Nuclear Retirement Case and High Load and Coal Retirement Case. Winter coincident peak hour load reported for the Polar Vortex Case.

**State of Illinois LOLE Summary for 2018 – 2019 Delivery Year**

| RTO | LBA/Transmission Zone | Case | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) |
|---|---|---|---|---|
| MISO | AMIL | Base Case | 0.000 | 0.000 |
| | | Nuclear Retirement Case | 0.000 | 0.000 |
| | | Polar Vortex | 0.000 | 0.000 |
| | | High Load and Coal Retirement Case | 0.002 | 0.000 |
| | | | | |
| | CWLP | Base Case | 0.000 | 0.000 |
| | | Nuclear Retirement Case | 0.000 | 0.000 |
| | | Polar Vortex | 0.000 | 0.000 |
| | | High Load and Coal Retirement Case | 0.000 | 0.000 |
| | | | | |
| | SIPC | Base Case | 0.000 | 0.000 |
| | | Nuclear Retirement Case | 0.000 | 0.000 |
| | | Polar Vortex | 0.000 | 0.000 |
| | | High Load and Coal Retirement Case | 0.007 | 0.001 |
| | | | | |
| PJM | COMED | Base Case | 0.000 | 0.000 |
| | | Nuclear Retirement Case | 0.000 | 0.000 |
| | | Polar Vortex | 0.089 | 0.002 |
| | | High Load and Coal Retirement Case | 0.159 | 0.017 |

The State of Illinois is divided between MISO and PJM, with Ameren Illinois participating in MISO and ComEd participating in PJM. As such, a single reliability indicator for LOLE is not reported for Illinois. Instead, LOLE is reported for each utility zone in the State in the four cases modeled.

### Summary of Modeling Methodology

GE-MARS performs a sequential Monte Carlo simulation to assess the reliability of MISO and PJM. In the sequential Monte Carlo model, multiple simulations of the annual pattern of generation availability within each RTO are developed by combining randomly-generated sequences of outage periods of each generating unit with inter-area transfer limits and hourly chronological loads. 2,000 iterations were run for each RTO for each scenario. Consequently, the state of each RTO – the amount of generating capacity available to meet load – is simulated in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies that govern system operation.

In each hour the model first computes the available generation, subject to random and planned outages, and demand response capacity located within each LBA in MISO and transmission zone in PJM. The available generation is subtracted from the hourly load forecasted for the LBA or transmission zone and if the hourly available generation exceeds hourly load, there is sufficient capacity in the zone. If there is insufficient available generation, demand response capacity is then considered.

GE-MARS then determines the additional capacity that might be transferred between LBAs in MISO and transmission zones in PJM, from those that have excess capacity available in a given hour to those that are short capacity, subject to the import and export limits modeled on the interfaces. GE-MARS optimizes the import and export of capacity across the RTOs in each simulation to minimize the loss of load in the RTO given zonal and RTO load in an hour. For each simulation, the total loss of load hours (LOLH) is calculated. The average LOLH for an RTO, across all simulations, is the estimated LOLE. A full description of the model is found in Appendix F.

### Case 1: Base Case

#### Assumptions Overview

The Base Case provides a baseline with which to compare the reliability impact of closing the at-risk nuclear plants. The detailed assumptions of the Base Case model are provided in Appendix C.

#### Analysis Results

Reliability in MISO, PJM and the State of Illinois is far below the target reliability standard of less than 0.1 LOLE in the Base Case.

**MISO, PJM & Illinois LOLE – Base Case for 2018 – 2019 Delivery Year**

| RTO | LBA or Transmission Zone | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) |
|---|---|---|---|
| MISO | AMIL | 0.000 | 0.000 |
| | CWLP | 0.000 | 0.000 |
| | SIPC | 0.000 | 0.000 |
| | **MISO RTO** | **0.076** | **0.004** |
| | | | |
| PJM | ComEd | 0.000 | 0.000 |
| | **PJM RTO** | **0.006** | **0.000** |

**MISO Commentary – Base Case (Case 1)**

As shown in the table above:

- Excellent expected reliability, LOLE is 0.000 for each of the three LBAs that comprise the MISO portion of Illinois (AMIL, CWLP and SIPC).
- Excellent expected reliability, LOLE for the MISO RTO is 0.004 with full demand response of 4,743 MW available and 0.076 without demand response available[105].

The Ameren Illinois LBA is a net exporter of capacity in the Base Case. As shown below, this LBA exports capacity in 621 hours (7% of 8,760), with an average export of 1,077 MW, providing capacity to other LBAs in MISO when they are short capacity during periods of high load and/or unplanned unit outages. The Ameren Illinois zone does not depend on capacity imports in the Base Case.

**Ameren Illinois LBA Base Case Capacity Imports and Exports**

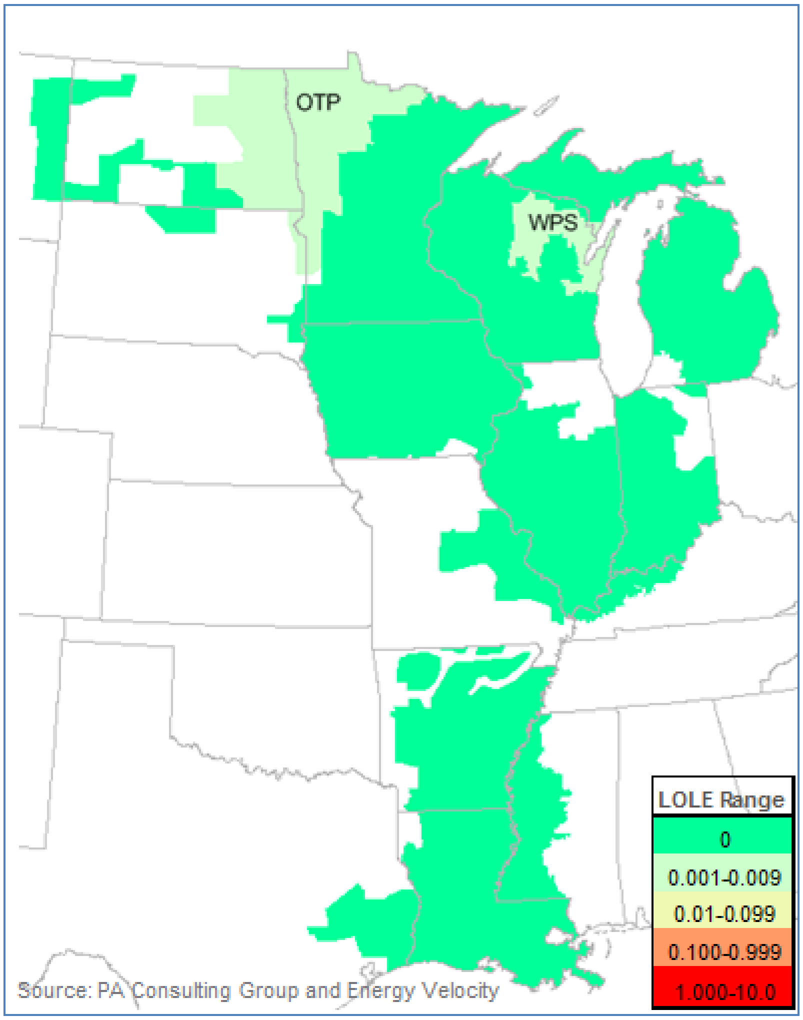
| | Number of Hours with Import/Export | % of Hours in Year with Import/Export | Average Import/Export (MW) |
|---|---|---|---|
| **Imports** | 0 | 0 | 0 |
| **Exports** | 621 | 7% | 1,077 |

The GE-MARS model indicates that approximately 800 MW of "perfect capacity" can be removed from the RTO before reaching an LOLE equal to 0.1 (before implementing any emergency procedures such as demand response) in the Base Case. "Perfect capacity" is capacity that never suffers outages, whose capability equals its nameplate (installed) capacity value and which is assumed to be able to support load anywhere irrespective of any transmission constraints.

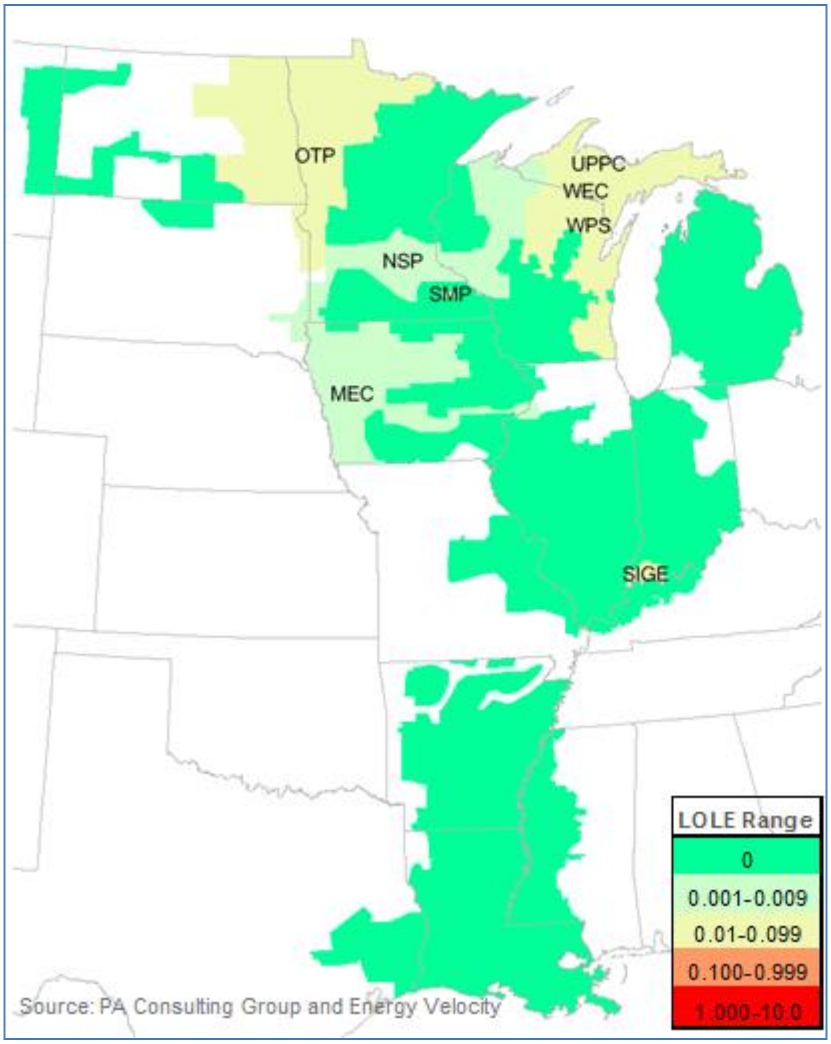
As shown in the following map, Otter Tail Power Company (located primarily in Minnesota and North Dakota) and Wisconsin Public Service Corporation are the only LBAs that experience an LOLE greater than zero when demand response resources are accounted for, while additional northern LBAs realize an LOLE greater than zero in the absence of demand resources. None of the LBAs experience an LOLE greater than 0.1 in the Base Case (both with and without the availability of demand response resources). Refer to Appendix K for the exact LOLE experienced in each LBA.

[105] MISO includes demand response resources in their LOLE analyses.

**MISO Base Case LOLE with Demand Response Resources**



**MISO Base Case LOLE without Demand Response Resources**




**PJM Commentary – Base Case (Case 1)**

As shown in the table above:

- Excellent expected reliability, LOLE is 0.000 for ComEd, which is the PJM transmission zone that comprises the PJM portion of Illinois.
- Excellent expected reliability, LOLE for the PJM RTO is 0.000 with full demand response of 12,402 MW available and 0.006 without demand response available.[106]

The ComEd transmission zone is not often relied on to provide capacity to other regions in PJM, nor does it require capacity imports to meet its reliability requirement. As shown below, the ComEd zone exports an average of 2,742 MW of capacity to other transmission zones in PJM via its transmission link with AEP in 1% of the hours in 2018/19 in the Base Case.

[106] PJM includes demand response resources in their LOLE analyses.

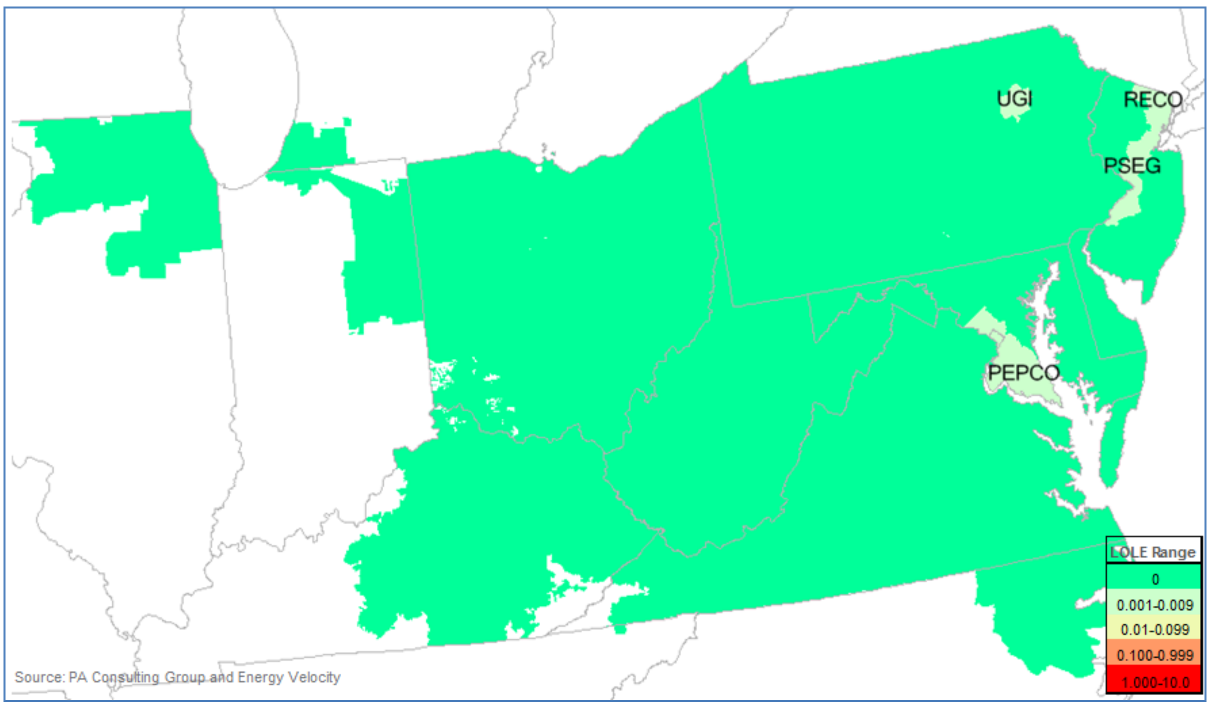
**PJM ComEd Zone Base Case Capacity Imports and Exports**

| | Number of Hours with Import/Export | % of Hours in Year with Import/Export | Average Import/Export (MW) |
|---|---|---|---|
| **Imports** | 0.1 | <1% | 501 |
| **Exports** | 124 | 1% | 2,742 |

Perfect capacity in PJM, which indicates the amount of capacity that can be removed from the RTO before reaching an LOLE equal to 0.1 (before implementing any emergency procedures such as demand response), is approximately 7,100 MW in the Base Case.

LOLE is equal to zero in all PJM transmission zones when demand response resources are accounted for and as shown in the map below, only a handful of transmission zones located in eastern PJM realize an LOLE greater than zero in the absence of demand resources. None of the transmission zones experience an LOLE greater than 0.1 in the Base Case (both with and without the availability of demand response resources). Refer to Appendix L for the exact LOLE experienced in each transmission zone.

**PJM Base Case LOLE without Demand Response Resources**



### Case 2: Nuclear Retirement Case

The Nuclear Retirement Case measures the impact of the closure of Byron units 1 & 2 (2,300 MW), Clinton unit 1 (1,065 MW) and Quad Cities units 1 & 2 (1,819 MW). No other changes were made to this case in order to isolate the impact of the nuclear plant closures on reliability.

#### Assumptions Overview

Byron units 1 & 2 and Quad Cities units 1 & 2, which account for 4,119 summer MWs, are located in PJM, while Clinton unit 1, which accounts for 1,065 summer MWs, is located in MISO. As a result, the retirement of the three at-risk plants decreases non-intermittent capacity in MISO from 156,540 summer MW to 155,475 summer MW and in PJM from 195,701 summer MW to 191,582 summer MW.

**Nuclear Retirement Case Assumption Changes**

| Case | Input Assumption | Change from Base Case |
|---|---|---|
| 2 - Nuclear Retirement Case | Peak Hour Load & Annual Energy | No change |
| | Demand Response | No change |
| | Installed Capacity | 3 nuclear plants are modeled as retired resulting in reduction of 5,184 MW of summer capacity. |
| | Unit Outage Rates | No change |

#### Analysis Results

As demonstrated below, the reliability impact of retiring these three at-risk nuclear plants is minimal and reliability in MISO, PJM and the State of Illinois is below the target reliability standard of less than 0.1 LOLE in the Nuclear Retirement Case.

**MISO, PJM & Illinois LOLE – Nuclear Retirement Case vs. Base Case for 2018 – 2019 Delivery Year**

| RTO | LBA or Transmission Zone | Base Case | | Nuclear Retirement Case | | Nuclear Retirement Case *minus* Base Case | |
|---|---|---|---|---|---|---|---|
| | | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) |
| MISO | AMIL | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| | CWLP | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| | SIPC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| | **MISO RTO** | **0.076** | **0.004** | **0.084** | **0.004** | **0.008** | **0.000** |
| PJM | ComEd | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| | **PJM RTO** | **0.006** | **0.000** | **0.032** | **0.000** | **0.026** | **0.000** |

**MISO Commentary – Nuclear Retirements (Case 2)**

As shown in the table above:

- Excellent expected reliability, as is the situation in the Base Case, LOLE is 0.000 for each of the three LBAs that comprise the MISO portion of Illinois (AMIL, CWLP and SIPC) in the Nuclear Retirement Case.
- Excellent expected reliability, LOLE for the MISO RTO is 0.004 with full demand response of 4,743 MW available and 0.084 without demand response available in the Nuclear Retirement Case. Both figures are similar to what was measured in the Base Case.

The Ameren Illinois LBA is still a net exporter of capacity in the Nuclear Retirement Case but at a lower level than in the Base Case. As shown below, the Ameren Illinois LBA is expected to export an average of 498.5 MW in 1% of the hours in 2018/19. The retirement of the Clinton nuclear generator reduces the amount of capacity that can be exported to other LBAs in MISO outside Illinois when they are short capacity during periods of high load and/or unplanned unit outages.

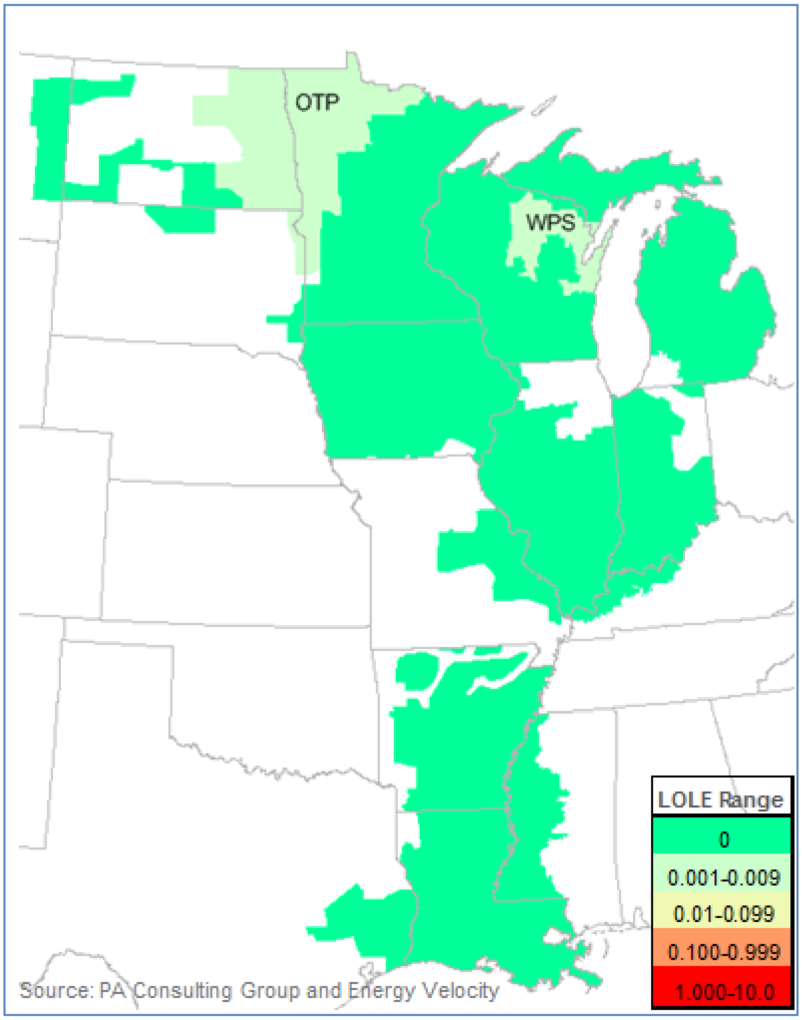
**Ameren Illinois LBA Capacity Imports and Exports– Base Case vs. Nuclear Retirement Case**

| | Number of Hours with Import/Export | % of Hours in Year with Import/Export | Average Import/Export (MW) |
|---|---|---|---|
| **Imports** | 0.1 | <1% | 0 |
| **Difference from Base** | 0.1 | <1% | 255.9 |
| **Exports** | 109.5 | 1% | 498.5 |
| **Difference from Base** | (511.5) | (6%) | (578.5) |

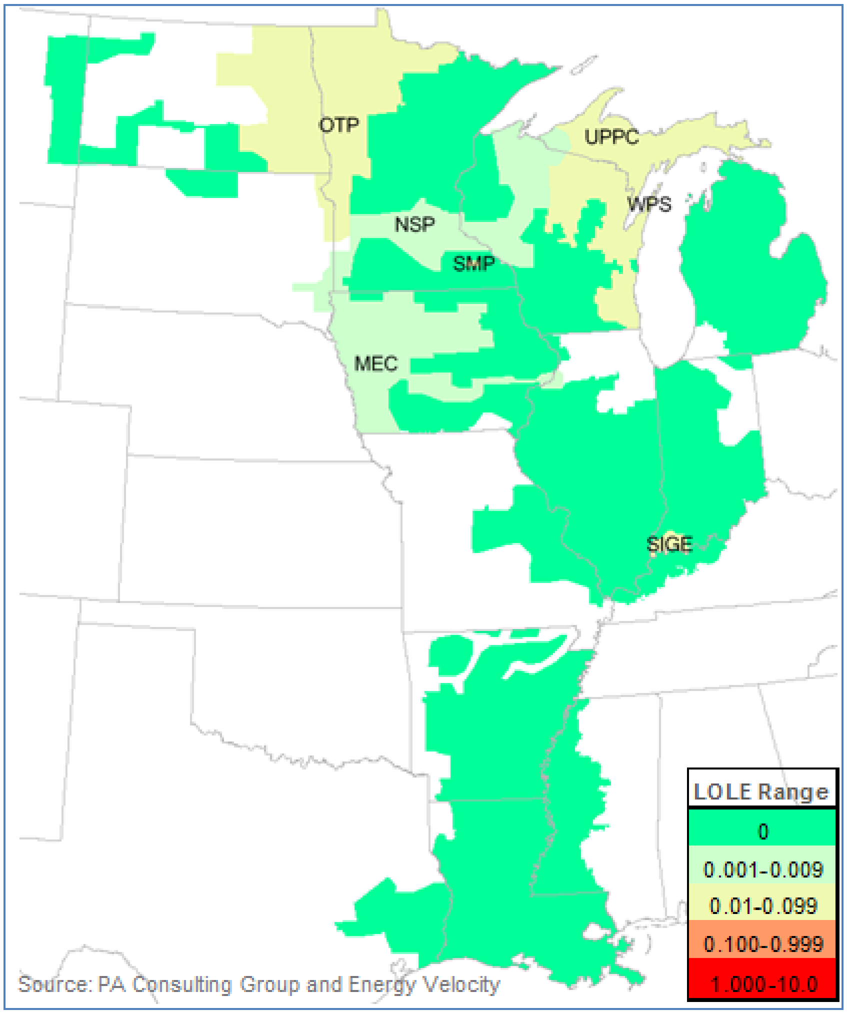
As noted above, removal of 800 MW of "perfect capacity" from the Base Case would have brought the LOLE below 0.1 (without the utilization of demand response resources), yet the removal of the 1,065 MW Clinton plant does not. Simple capacity metrics do not provide a complete picture of reliability. As demonstrated through the additional scenarios, reliability in the Ameren Illinois LBA exceeds reliability levels found in many other zones of MISO, indicating that the strength of Illinois' transmission connections enable it to easily call on reliability support from other zones. For the same reason, capacity located in Illinois may be more able to support reliability in other zones (especially in comparison to capacity located in more remote parts of MISO).

Similar to what is observed in the Base Case, Otter Tail Power Company and Wisconsin Public Service Corporation are the only LBAs that experience an LOLE greater than zero when demand response resources are accounted for, while additional northern LBAs realize an LOLE greater than zero in the absence of demand resources. None of the LBAs experience an LOLE greater than 0.1 in the Nuclear Retirement Case (both with and without the availability of demand response resources). Refer to Appendix K for the exact LOLE experienced in each LBA.

**MISO Nuclear Retirement Case LOLE with Demand Response Resources**



**MISO Nuclear Retirement Case LOLE without Demand Response Resources**




**PJM Commentary – Nuclear Retirements (Case 2)**

As shown in the table above:

- Excellent expected reliability, LOLE is 0.000 for the ComEd zone, which is the PJM transmission zone that comprises the PJM portion of Illinois in the Nuclear Retirement Case.
- Excellent expected reliability, LOLE for the PJM RTO is 0.000 with full demand response of 12,402 MW available and 0.032 without demand response available. PJM RTO LOLE increases a modest 0.026 relative to the Base Case.

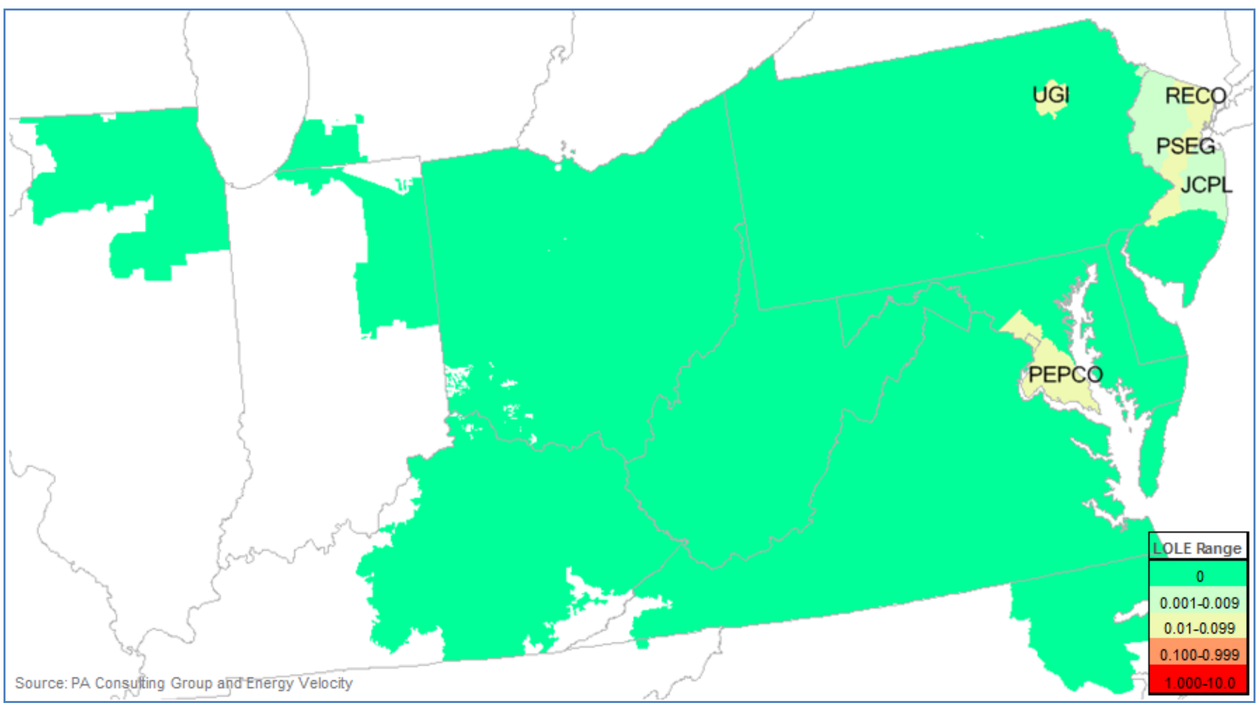
The ComEd transmission zone is not often relied on to provide capacity to regions in PJM, nor does it require capacity imports to meet its reliability requirement. As shown in below, the ComEd zone exports capacity to other transmission zones in PJM via its connection transmission link with AEP in 1% of the hours in 2018/19 in the Nuclear Retirement Case. The only noticeable impact of the retirement of Byron and Quad Cities relative to the Base Case is a drop in the average capacity supplied via transmission to other PJM transmission zones from 2,742 MW to 1,770 MW in the 1% of hours in which the ComEd zone is a capacity exporter.

**PJM ComEd Zone Capacity Imports and Exports– Base Case vs. Nuclear Retirement Case**

| | Number of Hours with Import/Export | % of Hours in Year with Import/Export | Average Import/Export (MW) |
|---|---|---|---|
| **Imports** | 32 | <1% | 885 |
| **Difference from Base** | 32 | <1% | 384 |
| **Exports** | 110 | 1% | 1770 |
| **Difference from Base** | (24) | (<1%) | (1042) |

As is the situation in the Base Case, LOLE is equal to zero in all PJM transmission zones when demand response resources are accounted for and only a handful of transmission zones located in eastern PJM realize an LOLE greater than zero in the absence of demand response resources in the Nuclear Retirement Case. None of the transmission zones experience an LOLE greater than 0.1 in the Nuclear Retirement Case (both with and without the availability of demand response resources). Refer to Appendix L for the exact LOLE experienced in each transmission zone.

**PJM Nuclear Retirement Case LOLE without Demand Response Resources**



### Case 3: Polar Vortex Case

The Polar Vortex Case investigates the impact on reliability of one week of weather similar to that experienced in MISO and PJM during early January 2014 (Jan. 5-7 in MISO and Jan. 6-7 in PJM) coupled with the retirement of Byron units 1 & 2, Clinton unit 1, and Quad Cities units 1 & 2. This is a stress test scenario based on a one-week extreme event with the impact observed during the 2014 "Polar Vortex" event, modeled as occurring during the 3rd week in January 2019. This case assumes impacts to load and resource availability similar to what was observed in 2014 (e.g., curtailment of natural gas delivery to power plants, or the freezing of coal piles). No assumption is implied as to the probability of a recurrence of the 2014 conditions. It is highly likely that other reforms and corrective actions would reduce the severity of the impact of a reoccurrence of the weather conditions of 2014. Given the recent experience with an event of this type, it is included in the modeling to test the range of possible outcomes.

#### Assumptions Overview

The high-level changes to input assumptions relative to the Base Case are demonstrated in the following table.

**Polar Vortex Case Assumption Changes**

| Case | Input Assumption | Change from Base Case |
|---|---|---|
| Polar Vortex Case | Peak Hour Load & Annual Energy | Winter load forecast increased by 8.1% in MISO and 9.0% in PJM for one week around the winter peak. |
| | Demand Response | Not available during week of Polar Vortex. |
| | Installed Capacity | 3 at-risk nuclear plants are modeled as retired resulting in a drop in winter capacity of 5,243MW. |
| | Unit Outage Rates | 16% market EFOR in MISO and 22% market EFOR in PJM for one week during Polar Vortex. |

The specific changes to assumptions are as follows:

- The winter coincident peak loads, which occur during the third week in January in both MISO and PJM, increase from 97,555 MW and 136,741, respectively, in the Base Case to 104,593 MW and 147,166, respectively, in the Polar Vortex Case;
- Zero demand response resources are available in MISO and PJM during the Polar Vortex (i.e. in the 3rd week in January 2019);
- Byron units 1 & 2 (2,346 MW), Clinton unit 1 (1,078 MW) and Quad Cities units 1 & 2 (1,819 MWs) are retired prior to 2018/19; and
- Unit availability is decreased to account for gas curtailment and issues such as frozen machinery and coal stocks. The market capacity-weighted forced outage rate increases

from 6% in MISO and PJM in the Base Case to 16% in MISO[107] and 22% in PJM[108]. This effectively means that 16% and 22 % of all capacity in MISO and PJM, respectively, is unavailable during the Polar Vortex.

**Analysis Results**

A Polar Vortex weather pattern occurring in conjunction with the retirement of the at-risk nuclear plants is not sufficient to degrade reliability to a point where it drops below the 0.1 LOLE standard in MISO or the State of Illinois in the Polar Vortex Case. However, it is sufficient enough to cause LOLE to exceed the Reliability Standard for PJM as a whole.

**MISO, PJM & Illinois LOLE – Polar Vortex Case vs. Base Case for 2018 – 2019 Delivery Year**

| RTO | LBA or Transmission Zone | Base Case | | Polar Vortex Case | | Polar Vortex Case *minus* Base Case | |
|---|---|---|---|---|---|---|---|
| | | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) |
| MISO | AMIL | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| | CWLP | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| | SIPC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| | **MISO RTO** | **0.076** | **0.004** | **0.093** | **0.013** | **0.017** | **0.009** |
| PJM | ComEd | 0.000 | 0.000 | 0.089 | 0.089 | 0.089 | 0.089 |
| | **PJM RTO** | **0.006** | **0.000** | **0.971** | **0.939** | **0.965** | **0.939** |

[107] MISO market EFOR determined based on capacity outage data provided as part of a review of the January 2014 polar vortex contained in *MISO January 2014 Polar Vortex Analysis: Impact of Potential Generator Retirements and Natural Gas Availability (Draft)*, June 2014, pp. 9-11.

[108] PJM market EFOR determined based on capacity outage data provided as part of a review of the January 2014 polar vortex contained in *Problem Statement on PJM Capacity Performance Definition, PJM Staff Draft Problem Statement*, August 1, 2014, pp. 6-8.

**MISO Commentary – Polar Vortex (Case 3)**

As shown in the table above:

- Excellent expected reliability, as is the situation in the Base Case, annual LOLE is 0.000 for each of the three LBAs that comprise the MISO portion of Illinois (AMIL, CWLP and SIPC) in the Polar Vortex Case.
- Good expected reliability, LOLE for the MISO RTO is 0.013 with full demand response of 4,743 MW available in every week of the year except the 3rd week of January (i.e. available every week of the year other than the week in which the Polar Vortex occurs) and 0.093 without demand response available during any week of the year in the Polar Vortex Case.

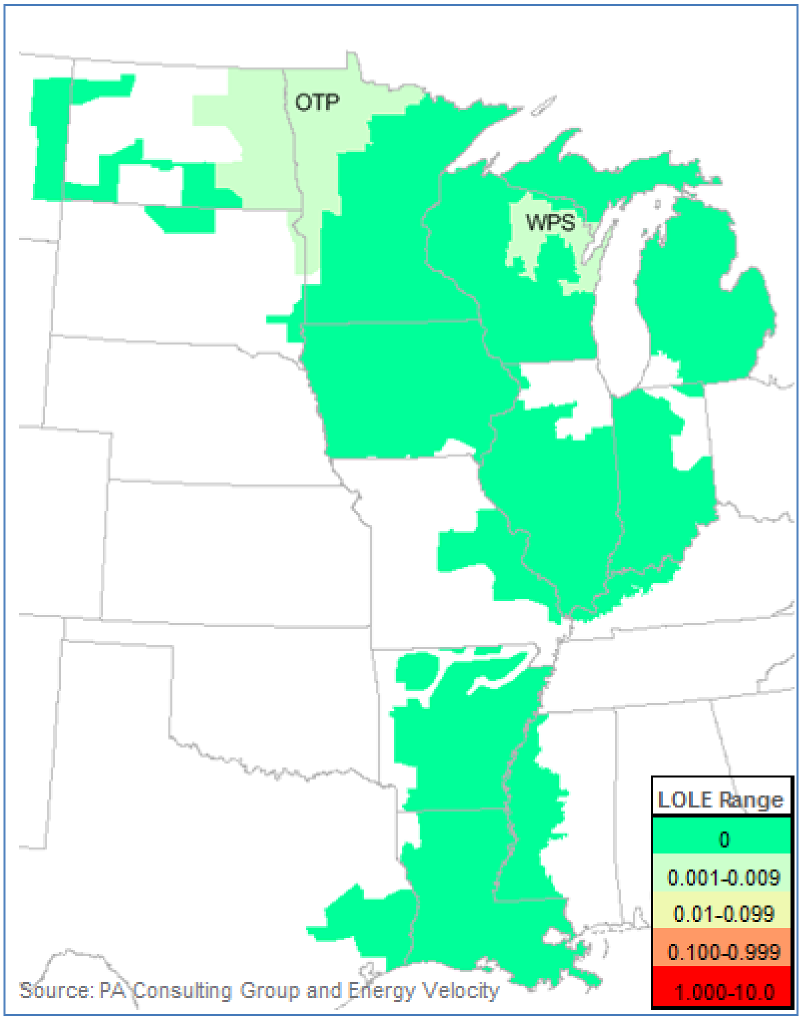
The following table shows the LOLE for MISO and the 3 Illinois LBAs in MISO broken out between the 3rd week in January (when the Polar Vortex occurs) and the remaining 51 weeks of the year (both with and without the availability of demand response resources in the remaining 51 weeks of the year). The Polar Vortex has minimal impact in the MISO RTO and the 3 Illinois LBAs, measuring 0.009 for the RTO and 0.000 in the 3 LBAs during the Polar Vortex weather event in the 3rd week of January. By comparison, overall MISO RTO LOLE is 0.004 with the availability of demand response resources and 0.084 when demand response resources are not available in the remaining 51 weeks of the year in which normal weather occurs.

**MISO and Illinois LBA LOLE – Polar Vortex Case with and without Demand Response for 2018 – 2019 Delivery Year**

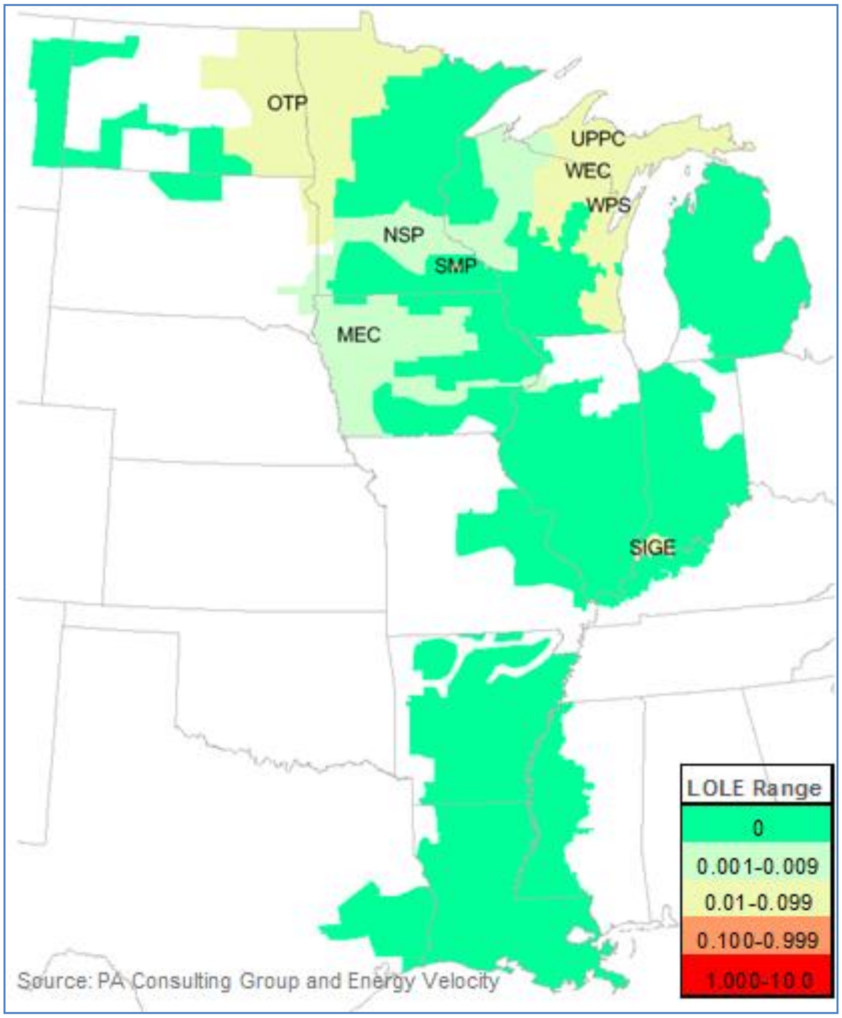
| | Demand Response Available (Except During 3rd Week of January) | | | Demand Response Not Available During Any Week of the Year | | |
|---|---|---|---|---|---|---|
| **Area** | **LOLE 3rd Week of January** | **LOLE Remaining 51 Weeks of the Year** | **Annual LOLE** | **LOLE 3rd Week of January** | **LOLE Remaining 51 Weeks of the Year** | **Annual LOLE** |
| AMIL | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CWLP | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| SIPC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| **MISO RTO** | **0.009** | **0.004** | **0.013** | **0.009** | **0.084** | **0.093** |

Similar to what is observed in the Base Case, Otter Tail Power Company and Wisconsin Public Service Corporation are the only LBAs that experience an LOLE greater than zero when demand response resources are available in the 51 weeks of the year during which the Polar Vortex is not occurring. When demand response resources are not available during any week in the year, a pattern of LBAs similar to the Base Case, located primarily in northern MISO, experience an LOLE greater than zero. None of the LBAs experience an LOLE greater than 0.1 in the Polar Vortex Case (both with and without the availability of demand response resources). Refer to Appendix K for the exact LOLE experienced in each LBA.

**MISO Polar Vortex Case LOLE with Demand Response Resources Available when the Polar Vortex is Not Occurring**



**MISO Polar Vortex Case LOLE without Demand Response Resources in any Week of the Year**




**PJM Commentary – Polar Vortex (Case 3)**

As shown in the table above:

- Good expected reliability, LOLE increases from 0.000 in the Base Case to 0.089 for the ComEd zone in the Polar Vortex Case (demand response resources have no impact on that increase as they are assumed unavailable during the winter event). While the increase in the ComEd zone is significant, LOLE is still below the reliability target.
- Fair expected reliability LOLE for the PJM RTO is 0.939 with full demand response of 12,402 MW available in every week of the year except the 3rd week of January (the week in which the Polar Vortex occurs) and 0.971 without demand response available during any week of the year in the Polar Vortex Case. Both are higher than the reliability standard and what was measured in the Base Case.

The next table shows the LOLE for PJM and the ComEd zone broken out between the 3rd week in January (when the Polar Vortex occurs) and the remaining 51 weeks of the year (both with and without the availability of demand response resources in the remaining 51 weeks of the year). The Polar Vortex has a significant impact in both regions.

- Fair expected reliability, LOLE in the PJM RTO, measuring 0.939 in the 3rd week in January, much worse than the reliability standard.
- Good expected reliability, LOLE during the 3rd week in January in the ComEd zone accounts for all of the 0.089 LOLE forecasted for the ComEd zone throughout the year, although 0.1 LOLE standard is not exceeded in the ComEd zone.

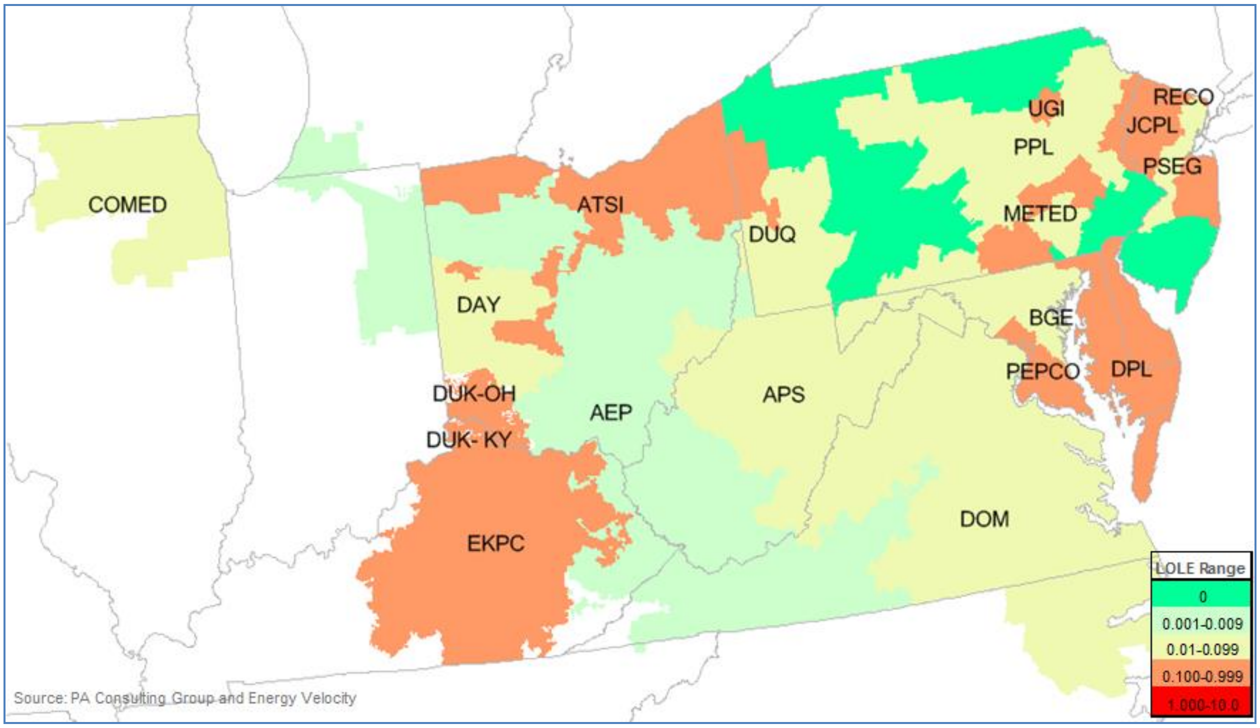
**PJM & ComEd LOLE – Polar Vortex Case with and without Demand Response for 2018 – 2019 Delivery Year**

| | Demand Response Available (Except During 3rd Week of January) | | | | Demand Response Not Available During Any Week of the Year | | |
|---|---|---|---|---|---|---|---|
| **Area** | **LOLE 3rd Week of January** | **LOLE Remaining 51 Weeks of the Year** | **Annual LOLE** | | **LOLE 3rd Week of January** | **LOLE Remaining 51 Weeks of the Year** | **Annual LOLE** |
| ComEd Zone | 0.089 | 0.000 | 0.089 | | 0.089 | 0.000 | 0.089 |
| **PJM RTO** | **0.939** | **0.000** | **0.939** | | **0.939** | **0.032** | **0.971** |

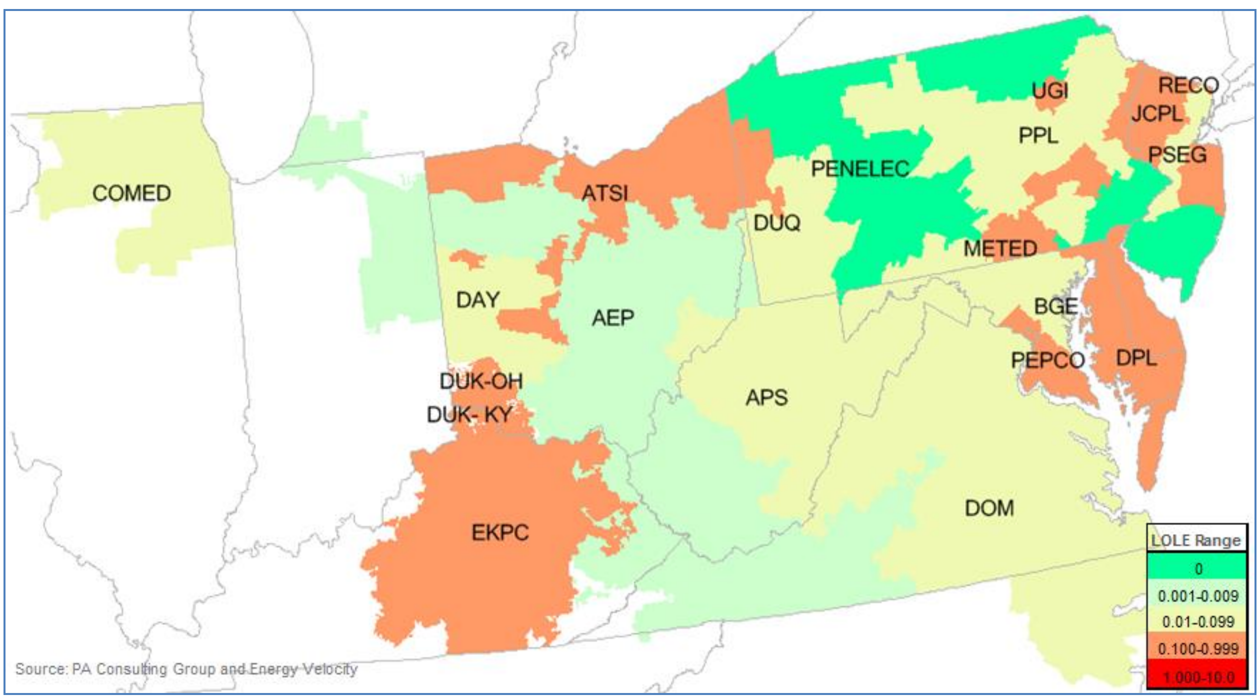
LOLE in PJM is greater than zero in the majority of the transmission zones in the Polar Vortex Case when demand response resources are available in every week of the year besides the third week in January. Given the severity of the Polar Vortex conditions, LOLE exceeds 0.1 in transmission zones comprising parts of Ohio, Pennsylvania, Maryland and New Jersey.

Because the Polar Vortex produces a high LOLE, there is little difference between LOLE in transmission zones when demand response is not available during any week of the year. Refer to Appendix L for the exact LOLE experienced in each transmission zone.

**PJM Polar Vortex Case LOLE with Demand Response Resources Available when there is no Polar Vortex**




**PJM Polar Vortex Case LOLE without Demand Response Resources in any Week of the Year**



### Case 4: High Load and High Coal Retirements Case

The High Load and High Coal Retirement Case investigates the impact on reliability of higher load, more coal plant retirements, and the retirement of Byron units 1 & 2, Clinton unit 1, and Quad Cities units 1 & 2.

#### Assumptions Overview

The high-level changes to input assumptions relative to the High Load and Coal Retirements Case are shown below.

**High Load and Coal Retirements Case Assumption Changes**

| Case | Input Assumption | Change from Base Case |
|---|---|---|
| High Load and Coal Retirement Case | Peak Hour Load & Annual Energy | Peak hour non-coincident load and annual energy forecast increased by 6.0% in MISO and PJM. |
| | Demand Response | No change |
| | Installed Capacity | • 3 at-risk nuclear plants are modeled as retired resulting in a drop in summer capacity of 5,184 MW.<br>• An additional 6,221 MW and 7,160 MW of coal-fired generation modeled as retired (summer capacity) in MISO and PJM respectively. |
| | Unit Outage Rates | No change |

The impact of the changes to input assumptions are as follows:

- The summer coincident peak loads in MISO and PJM increase from 129,157 MW and 162,995 MW, respectively, in the Base Case to 135,578 MW and 171,353 in the High Load and Coal Retirements Case. Peak hour load and annual energy increases for both MISO and PJM are based on the increase in high (90/10) peak hour load forecast relative to the summer peak load forecast for PJM contained in the 2014 PJM Load Forecast Report, January 2014. A high annual energy forecast was not provided in the PJM report. Therefore the 6% increase in the peak hour load was also applied to annual energy. A high peak hour load forecast was not available for MISO, so the 6% increase between PJM base and high peak hour load was also applied to MISO;
- Byron units 1 & 2 (2,300 MW), Clinton unit 1 (1,065 MW) and Quad Cities units 1 & 2 (1,819) MWs) are retired prior to 2018/19; and
- Coal plant retirements increase by 6,221 MW in MISO and 7,160 MW in PJM. The combined effect of the coal and at-risk nuclear plant retirements decreases summer installed capacity for non-intermittent generation (i.e. all generation besides wind and

solar) from 156,540 MW in MISO and 195,701 MW in PJM in the Base Case to 149,254 MW and 184,422 MW, respectively.

- Coal plant retirements in MISO are in line with potential retirements cited in the MISO 2013 State of the Market Report, which is developed by Potomac Economics, the Independent Market Monitor for MISO.[109]
- Coal plant retirements in PJM are in line with potential retirements cited in the PJM 2017/18 RPM Base Residual Auction Results Report.[110]

**Analysis Results**

The impact of high load, increasing the amount of coal capacity retired, and retiring the at-risk nuclear plants on reliability in Illinois is minimal relative to the Base Case. On the other hand, reliability in other parts of MISO is impacted and exceeds the reliability standard, while LOLE in other parts of PJM increases relative to the Base Case but is still below the standard.

**MISO, PJM & Illinois LOLE – High Load and Coal Retirements Case vs. Base Case for 2018 – 2019 Delivery Year**

| RTO | LBA or Transmission Zone | Base Case | | High Load and Coal Retirements Case | | High Load and Coal Retirements Case *minus* Base Case | |
|---|---|---|---|---|---|---|---|
| | | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) | LOLE (Days/Year) (Without Demand Response) | LOLE (Days/Year) (With Demand Response) |
| MISO | AMIL | 0.000 | 0.000 | 0.002 | 0.000 | 0.002 | 0.000 |
| | CWLP | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| | SIPC | 0.000 | 0.000 | 0.007 | 0.001 | 0.007 | 0.001 |
| | **MISO RTO** | **0.076** | **0.004** | **3.013** | **0.638** | **2.937** | **0.634** |
| PJM | ComEd | 0.000 | 0.000 | 0.159 | 0.017 | 0.000 | 0.000 |
| | **PJM RTO** | **0.006** | **0.000** | **1.877** | **0.086** | **1.871** | **0.086** |

**MISO Commentary – High Load and High Retirements (Case 4)**

As shown in the table above:

- Excellent expected reliability, LOLE is slightly above zero for AMIL (without demand response resources available) and SIPC (both with and without demand response resources available) in the High Load and Coal Retirements Case.
- Fair expected reliability, LOLE for the MISO RTO is 0.638 with full demand response of 4,743 MW available and 3.013 without demand response available in the High Load and

[109] https://www.misoenergy.org/MarketsOperations/IndependentMarketMonitor/Pages/IndependentMarketMonitor.aspx

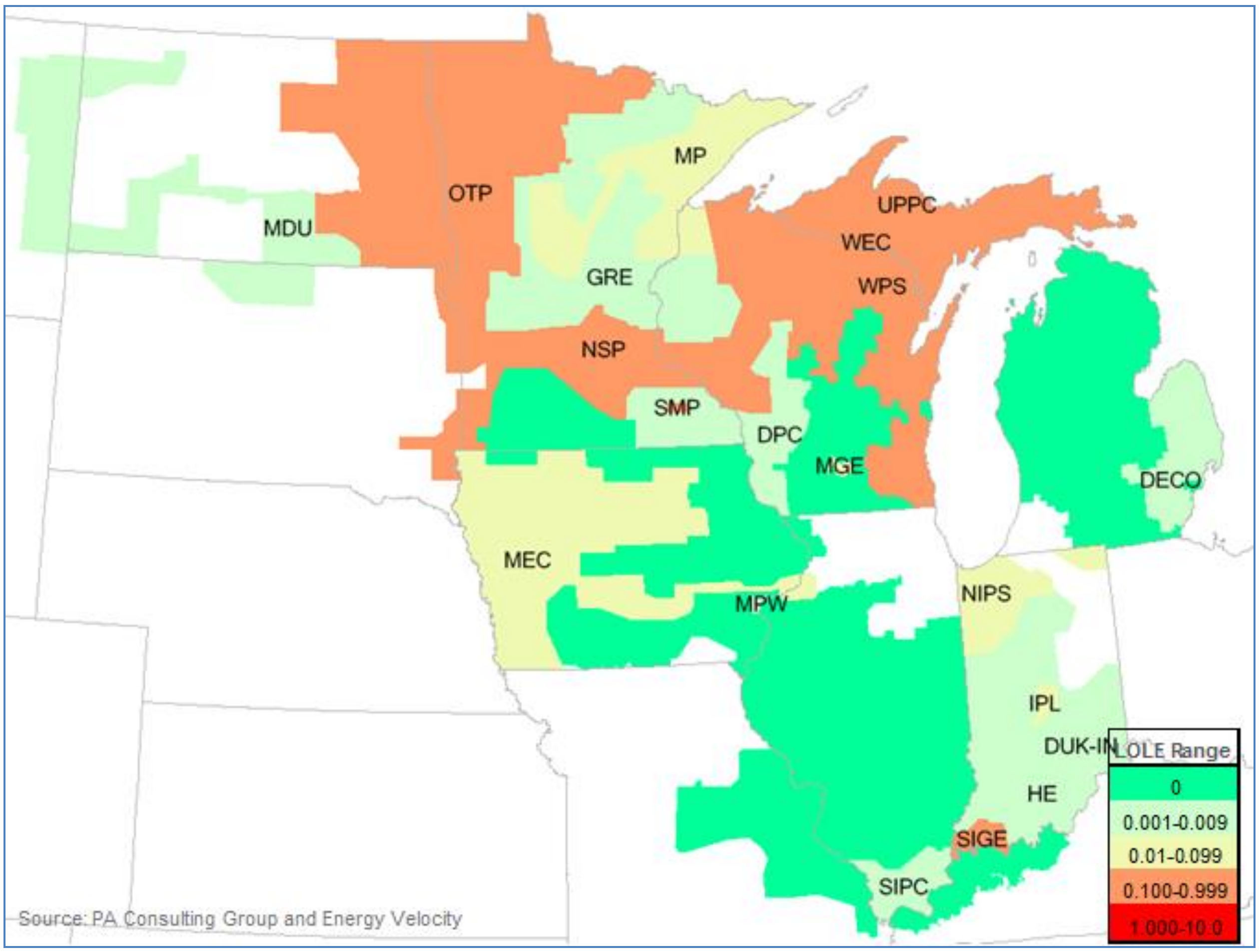
[110] http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx

Coal Retirement Case. This represents a significant increase in LOLE relative to the Base Case and exceeds the reliability standard.

As shown in the following map, the reliability impacts are most significant in northern LBAs and LOLE is greater than 0.1 in the following when demand resources are accounted for in the High Load and Coal Retirement Case:

- Northern States Power Company,
- Otter Tail Power Company,
- Southern Indiana Gas & Electric Co.,
- Southern Minnesota Municipal Power Agency,
- Upper Peninsula Power Co.,
- Wisconsin Energy Corporation, and
- Wisconsin Public Service Corporation.

**MISO High Load and Coal Retirement Case LOLE with Demand Response Resources**



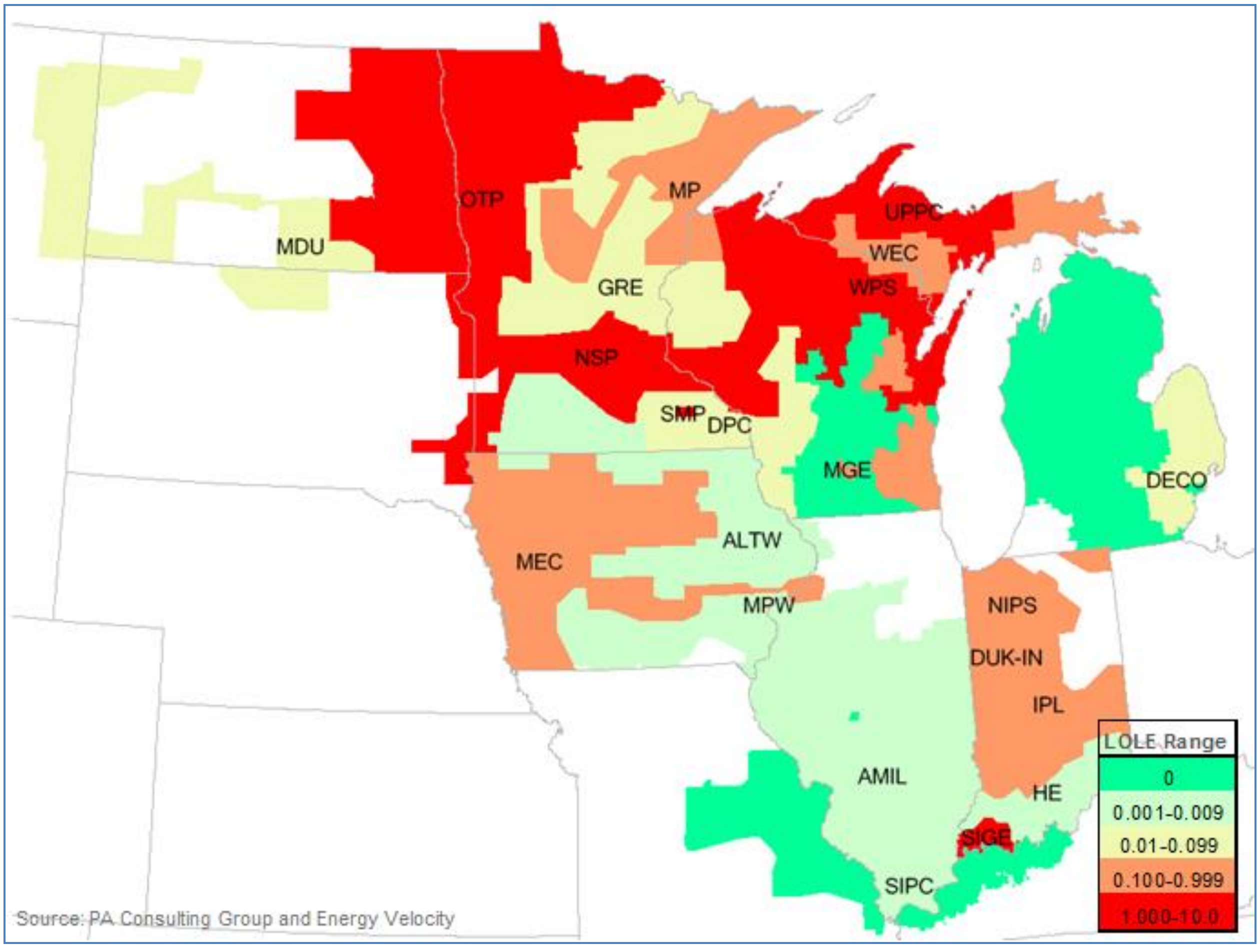

As shown in the next map, the list of LBAs where LOLE is greater than 0.1 expands to include the following when demand response resources are not available:

- Duke Energy Indiana,
- Indianapolis Power & Light Company,
- MidAmerican Energy Company,

- Madison Gas and Electric Company,
- Minnesota Power Inc., and
- Northern Indiana Public Service Company.

Refer to Appendix K for the exact LOLE experienced in each LBA.

**MISO High Load and Coal Retirement Case LOLE without Demand Response Resources**




**PJM Commentary – High Load and High Retirements (Case 4)**

As shown in the table above:

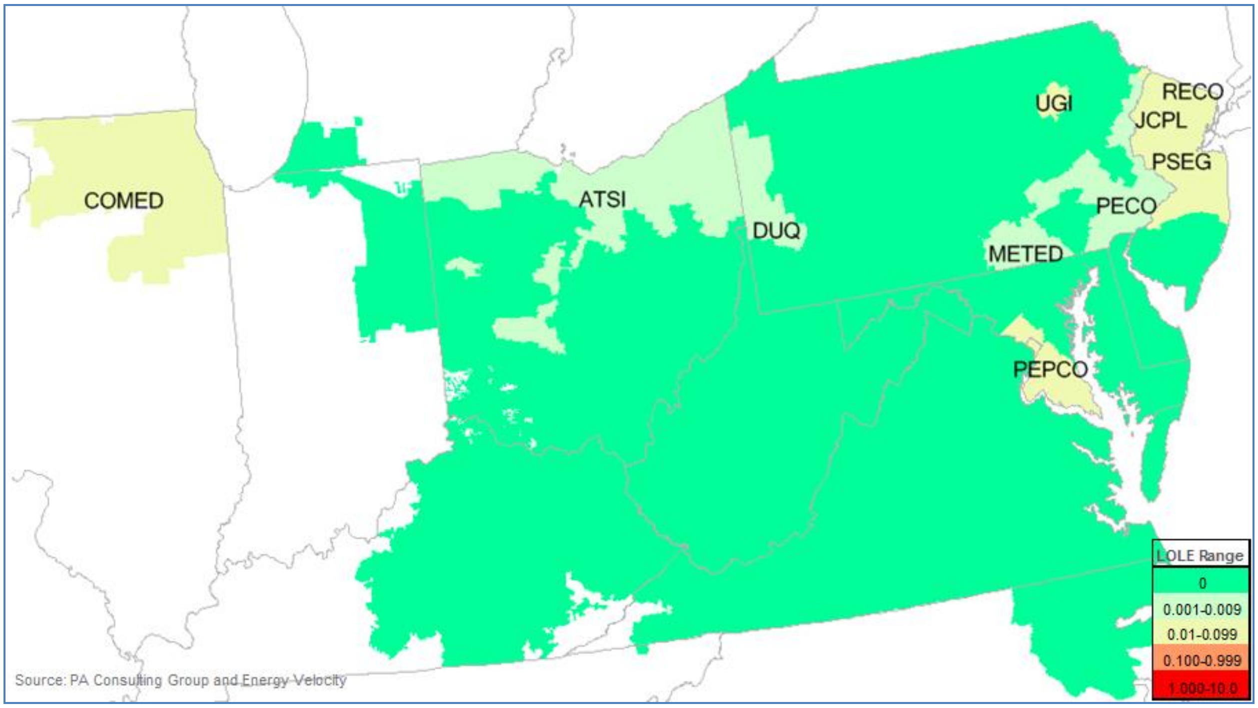
- Excellent expected reliability, LOLE increases in ComEd from 0.000 in the Base Case to 0.017 with demand response resources available, and
- Fair expected reliability, LOLE 0.159 in the ComEd zone without demand response resources available.
- Excellent expected reliability, LOLE for the PJM RTO is 0.086 with full demand response of 12,402 MW available, and
- Poor expected reliability, LOLE 1.877 for the PJM RTO without demand response available.

The reliability standard is not violated in any PJM transmission zone in the High Load and Coal Retirement Case when demand response resources are available. The transmission zones that realize the greatest increase in LOLE relative to the Base Case are Potomac Electric Power Company, Public Service Electric & Gas Company, Rockland Electric Company and UGI Utilities, Inc., all of which are located in transmission constrained eastern PJM.

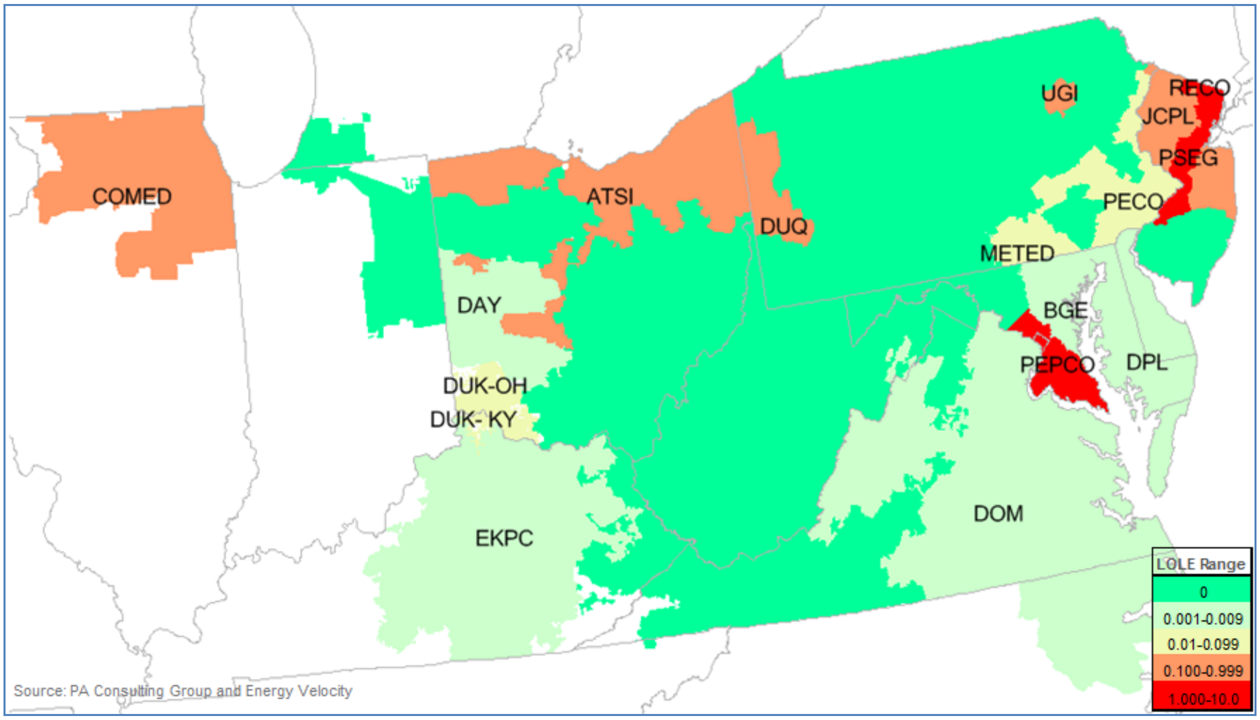
Without the availability of demand response resources, LOLE increases dramatically in PJM where RTO LOLE increases from 0.006 in the Base Case to 1.877 in the High Load and Coal Retirement Case. LOLE increases above the Reliability Standard in many eastern transmission zones and also coal-reliant Ohio.

Refer to Appendix L for the exact LOLE experienced in each transmission zone.

**PJM High Load and Coal Retirement Case LOLE with Demand Response Resources**



**PJM High Load and Coal Retirement Case LOLE without Demand Response Resources**




**Additional Uncertainties and Modeling Issues**

In the process of developing the model inputs, and reviewing the outputs, the IPA and its consultants have identified a number of important uncertainties that may need to be resolved over the next several years. In addition, certain modeling assumptions affect the results obtained. One key uncertainty, discussed in Appendix M, is the level of baseload coal retirements. Other sources of uncertainty (and potential discrepancies between the IPA's and the RTOs' analyses) include:

**Data Sources**

There are multiple data sources that purport to contain information about existing generators, planned retirements and planned additions. The PJM and MISO RTOs base their own modeling on proprietary data they have assembled from their members and internal analyses. The NERC ES&D database is the "official" basis for reliability assessments; however, only summary data is publicly available. The public NERC ES&D no longer includes individual unit data (i.e. the Schedule 2 data) because of confidentiality issues for some units. Unit capacities are derated for reliability reporting purposes – derations are particularly large in MISO – and the deration amounts may be proprietary. Assumptions for this study are based on a commercially available database from Ventyx, as well as a review of recent items in the public and trade press. The IPA believes that public policy discussions should be based on complete publicly available information and for that reason has attempted to base its analysis on data sources that are freely or commercially available. Use of such data sources allows other parties to better scrutinize the quantitative assumptions.

**Unit Additions**

The reliability modeling in this report focuses on 2018-2019, the first year for which PJM capacity obligations have not been determined. MISO capacity obligations have only been determined through 2014-2015. The forecast of generation additions is based on units under construction and announcements of expected development, with a certain amount of market and commercial insight applied. Experience has shown, though, that in periods of extreme stress on the generation system a certain amount of capacity can be added quickly (new peakers, barge-mounted generators, return to service of recent retirements) even if those new additions are short-lived.

Any forecast of MISO resource adequacy over the next several years is necessarily more uncertain than a forecast of PJM resource adequacy. PJM's RPM process has a three-year projection horizon, which means that capacity is committed to PJM three years ahead. MISO's Planning Reserve Auction yields only a one-year commitment. Resource planning processes in some MISO states may produce longer-term commitments.

**Potential Nuclear Power Plant Closings in Illinois**

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Social Cost of Carbon

CHAPTER 3. ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S RESPONSE

***RESOLVED, That we urge the Illinois Environmental Protection Agency to prepare a report showing how the premature closure of existing nuclear power plants in Illinois will affect the societal cost of increased GHG emissions based upon the EPA's published societal cost of GHG;***

# ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S RESPONSE

## Potential Impacts of Nuclear Power Plant Closures in terms of the Social Cost of Carbon

### Background

House Resolution No. 1146 which directs the Illinois Environmental Protection Agency to prepare a report for the Governor and General Assembly that:

I. Shows how the premature closure of existing nuclear power plants in Illinois would affect the societal cost of increased greenhouse gas ("GHG") emissions based upon the United States Environmental Protection Agency's ("USEPA") published societal cost of GHG, and

II. Includes potential market-based solutions that could be used to comply with USEPA's proposed Clean Power Plan under section 111(d) of the Clean Air Act that would ensure that the premature closure of Illinois' nuclear power plants does not occur.

This report estimates the cost to society of any increase in $CO_2$ emissions associated with nuclear power plant closures using USEPA's Social Cost of Carbon ("SCC"). USEPA and other federal agencies use the SCC to estimate the climate costs and benefits of rulemakings. The SCC is meant to be a comprehensive estimate of climate change damages, including damages to agricultural productivity, human health, and property. Estimates are made in terms of the economic damages associated with increased $CO_2$ emissions in a given year and results are often presented over a time period consisting of several years. The SCC is a rate, in dollars per ton of emissions. In this report, this SCC rate is multiplied by the calculated additional $CO_2$ emissions that result from a potential loss of nuclear generation and the associated increase in generation from other available power sources. To determine the additional $CO_2$ emissions, the estimated amount of generation lost from nuclear EGUs will be multiplied by the carbon intensity (i.e., $CO_2$ emissions rate per amount of power generated) of the replacement generation sources.

### Nuclear Power in Illinois

Exelon Nuclear Partners, a division of Exelon Generation, operates six nuclear power plants in Illinois with eleven Electric Generating Units ("EGUs"). These eleven EGUs generate nearly half of Illinois' power and emit no $CO_2$. Relevant information for the Illinois plants is contained in the table below:

| Plant and Units | Summer Capacity* (Megawatts) | Approximate % of Total IL Nuclear Capacity |
|---|---|---|
| **Braidwood** | | |
| Unit 1 | 1,178 | 10% |
| Unit 2 | 1,152 | 10% |
| **Byron** | | |
| Unit 1 | 1,164 | 10% |
| Unit 2 | 1,136 | 10% |
| **Clinton** | | |
| Unit 1 | 1,065 | 9% |
| **Dresden** | | |
| Unit 2 | 883 | 7.5% |
| Unit 3 | 867 | 7.5% |
| **LaSalle** | | |
| Unit 1 | 1,137 | 10% |
| Unit 2 | 1,140 | 10% |
| **Quad Cities** | | |
| Unit 1 | 908 | 8% |
| Unit 2 | 911 | 8% |
| **Total** | 11,541 | 100% |

**2012 Energy Information Administration Form 806*

**Clean Power Plan**

On June 2, 2014 USEPA proposed the Clean Power Plan guidelines to reduce carbon dioxide (“$CO_2$") emissions from existing fossil-fuel power plants. This proposal was issued under section 111(d) of the Clean Air Act. The proposal:

1. Establishes state specific $CO_2$ emission rate reduction goals for existing power plants. For each state, there is an interim goal to be met over the 10-year period from 2020 through 2029, and a final goal to be met by 2030 and thereafter.
2. Provides guidelines each state must follow in developing, submitting, and implementing its state plan to comply with the emission reduction goals.

### Replacement Power

In the short-term, if nuclear power plants in Illinois were retired, the lost base load electricity generation would likely be replaced by some combination of existing fossil fuel-fired (e.g., coal and natural gas) base load Illinois EGUs with some amount of the generation being replaced by renewable energy ("RE") sources, such as wind and solar. Any lost nuclear generation that is replaced with alternative forms of energy would likely result in an increase in the emissions of $CO_2$, the amount of which would be dependent upon the replacement mix. For example, if the lost nuclear generation is largely replaced by coal-fired EGUs, there would be a significant increase in $CO_2$ emissions as coal-fired units emit the greatest amount of $CO_2$ of the fuel types utilized.

In the long-term, if the lost generation is primarily replaced by a combination of natural gas and zero or low $CO_2$ emitting RE EGUs, the increase in $CO_2$ is mitigated.

### Economic Valuation of $CO_2$ Emissions

A USEPA fact sheet[111] explains that the present value per metric ton of $CO_2$ emissions in selected future years ranges widely from $12 to $235. Past changes in emissions have a longer lived economic impact than changes in emissions that might occur in the future. However, future emissions are assumed to be more impactful than emissions which occur today. The range in values of the SCC is also attributed to the discount rate assumed in present value calculations and the inclusion of a high-cost scenario from the integrated assessment models.

Table 1 provides the SCC estimates updated by USEPA in 2013. This report utilizes mid-range values based on a 3% discount rate.

[111] http://www.epa.gov/climatechange/Downloads/EPAactivities/scc-fact-sheet.pdf

Table 1: USEPA Social Cost of Carbon

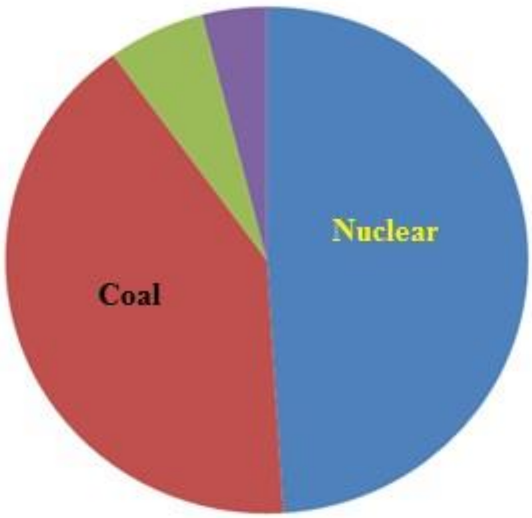
| Social Cost of $CO_2$, 2015-2050 a (in 2011 Dollars) *Dollars per metric ton of emissions* | | | | |
|---|---|---|---|---|
| | Discount Rate and Statistic | | | |
| Year | 5.0% Average | 3.0% Average | 2.5% Average | 3.0% 95th percentile |
| 2015 | $12 | $39 | $61 | $116 |
| 2020 | $13 | $46 | $68 | $137 |
| 2025 | $15 | $50 | $74 | $153 |
| 2030 | $17 | $55 | $80 | $170 |
| 2035 | $20 | $60 | $85 | $187 |
| 2040 | $22 | $65 | $92 | $204 |
| 2045 | $26 | $70 | $98 | $220 |
| 2050 | $28 | $76 | $104 | $235 |

*The SCC values are dollar-year and emissions-year specific*

**Electricity Generation in Illinois**

The following chart shows 2012 electricity generation from Illinois' power suppliers along with the carbon intensity for each generation source. The power generation mix may vary from year to year dependent upon several factors, including the cost of fuel and programs in place that provide incentives for specific types of generation. Power demand is expected to grow in future years and should be offset to some degree by growth in demand-side energy efficiency ("EE"). According to the U.S. Energy Information Administration ("EIA"), electricity demand growth is expected to remain relatively low as rising demand is offset by EE gains. Nationally, total electricity demand growth is forecast at 0.9% per year from 2012 to 2040.

2012 Illinois Net Electricity Generation and Carbon Intensity




| Generation Source | Percent of Total | Carbon Intensity (metric tons $CO_2$/MWh) |
|---|---|---|
| Nuclear | 49% | 0 |
| Coal | 41% | 1.0 |
| Natural Gas | 6% | 0.5 |
| Renewable | 4% | 0 |

*All data from Energy Information Administration*

In 2012, the net electricity generation from Illinois sources was around 197,565,363 MWh. Approximately 74% of the electricity generated by Illinois sources is consumed within the state. EIA data shows that in 2012 around 20% of the electricity generated in Illinois was used outside of the state, around four percent was attributed to energy losses, and for the remaining two percent was unaccounted.

**Nuclear Power Profile**

Nuclear power generation in Illinois approximates 100,000,000 MWh annually (the largest amount of any state) according to the EIA. The proposed Clean Power Plan suggests that a certain percentage of the nation's nuclear EGUs are "at-risk" for retirement due to economic challenges. The nation-wide at-risk generation amount was determined to be around six percent based on the EIA's Annual Energy Outlook, although the percentage may be higher for Illinois' nuclear EGUs as revenues have been negatively impacted by capacity markets and by operating in MISO. Economic pressure on nuclear plants may exist due to low-cost natural gas, slow electricity demand growth, and market structures and government policies.

If nuclear power plants in Illinois are retired, the lost base load electricity generation will likely be primarily replaced by some combination of existing fossil fuel-fired base load and RE sources, such as wind and solar, which have historically been non-base load sources. The entire amount of lost nuclear generation may not need to be replaced to the extent that EE programs are successful and reduce the need for power.

**Fossil Fuel Power Profile**

Fossil fuel power generation in Illinois approximates 85,000,000 MWh annually with over 75% of the generation coming from coal-fired sources and the remainder from primarily natural gas-fired sources. Between 2005 and 2013, the state-wide average carbon intensity of coal-fired generation has ranged from a high of 1.075 short-tons[112] per MWh in 2011 to a low of 1.039 in 2013. Natural gas carbon intensity ranged from 0.56 in 2005 to 0.49 in 2012.

### Renewable Energy Profile

In 2012, RE generation comprised around four percent of the total power generation in Illinois with almost all of this generation coming from wind power. In 2013, Illinois was home to around 2,195 wind turbines with a capacity of approximately 3,600 MW. Illinois currently has several programs in place that require and/or provide incentives for new RE in the state. These include the Renewable Portfolio Standard (RPS) which requires Illinois utilities provide 10% of their power from RE sources by 2015 and 25% by 2025.

### Energy Efficiency

Illinois currently implements several measures that result in avoided generation. These include the Energy Efficiency Portfolio Standard (EEPS) which requires Illinois utilities to reduce overall electric usage by two percent in 2015 and each year thereafter. The EEPS provides for incentives in the form of rebates to Illinois utility customers to encourage the purchase and installation of high efficiency equipment and systems to reduce electricity usage.

## Estimates of the SCC from Nuclear Retirements

The following provides four scenarios of assumed nuclear generation retirement and replacement generation mix.

### Scenario 1: Possible - Single Plant Retirement

This is a scenario where 9% of the nuclear power generation capacity is assumed to be retired, an amount equal to Clinton's capacity, and a realistic mix of generation sources replace the lost generation during the years 2020 through 2029.

In this scenario the replacement generation mix is as follows:

This ratio of replacement generation was determined using the ratio of 2012 actual generation amounts for coal, natural gas, and RE (i.e., 41/51, 6/51 and 4/51).

<u>Replacement Generation Mix:</u>

- Coal-fired: 80%
- Natural Gas fired: 12%
- RE: 8%

The SCC for each metric ton emitted in years 2020 thru 2024 is estimated to be $46, and $50 per metric ton emitted for the years 2025 thru 2029.

[112] A short-ton is about 90% of the amount of a metric ton.

9,000,000 MWh of nuclear generation is replaced.

The Carbon Intensity of the replacement generation mix is 0.86 metric tons per MWh - estimated from (0.8*1 metric ton/MWh) + (0.12*0.5 metric tons/MWh) + (0.08*0 metric tons/MWh).

Emissions, the product of generation multiplied by Carbon Intensity, are 7,740,000 metric tons of $CO_2$ in the year 2025. The annual present social cost is estimated to be:

(7,740,000 metric tons * $50/metric ton) = $387 million.

SCC = $0.4 billion for emissions occurring in 2025 alone.

The SCC if these emissions occur each year for the decade of 2020 thru 2029 is estimated to be:

(5 years * 7,740,000 metric tons/year * $46/metric ton) +

(5 years * 7,740,000 metric tons/year * $50/metric ton) = $3.715 billion

- SCC = $3.7 billion for emissions occurring over the decade of 2020 to 2029

**Scenario 2: Two Plant Retirement**

This is a scenario where 25% of the nuclear power generation capacity is retired, reflecting the potential shutdown of Clinton and Quad Cities nuclear power plants, and a realistic mix of generation sources replaces the lost generation during the years 2020 through 2029.

In this scenario the replacement generation mix is as follows:

<u>Replacement Generation Mix:</u>

- Coal-fired: 80%
- Natural Gas fired: 12%
- RE: 8%

The SCC for each metric ton emitted in years 2020 thru 2024 is estimated to be $46, and $50 per metric ton emitted for the years 2025 thru 2029.

25,000,000 MWh of nuclear generation is replaced.

The Carbon Intensity of the replacement generation mix is 0.86 metric tons per MWh - estimated from (0.8*1 metric tons/MWh) + (0.12*0.5 metric tons/MWh) + (0.08*0 metric tons/MWh).

Emissions, the product of generation multiplied by Carbon Intensity, are 21,500,000 metric tons of $CO_2$ in the year 2025.

The SCC if these emissions occur each year for the decade of 2020 thru 2029 is estimated to be:

(5 years * 21,500,000 metric tons/year * $46/metric ton) +

(5 years * 21,500,000 metric tons/year * $50/metric ton) = $10.32 billion

- SCC = $10.3 billion for emissions occurring over the decade of 2020 to 2029

**Scenario 3: Three Plant Retirement**

This is a scenario where 45% of the nuclear generation in Illinois is retired and the lost generation is replaced by the same historic mix of generation sources used in scenarios 1 and 2. This loss of 45% is equivalent to three of Illinois' nuclear power plants (i.e., Clinton, Byron, and Quad Cities) retiring all of their EGUs.

<u>Replacement Generation Mix:</u>

- Coal-fired: 80%
- Natural Gas fired: 12%
- RE: 8%

The SCC for each metric ton emitted in years 2020 thru 2024 is estimated to be $46, and $50 per metric ton emitted for the years 2025 thru 2029.

45,000,000 MWh nuclear generation is replaced.

The Carbon Intensity of the replacement generation mix is 0.86 metric tons per MWh - estimated from (0.80*1 metric tons/MWh) + (0.12*0.5 metric tons/MWh) + (0.08*0 metric tons/MWh).

Emissions, the product of generation multiplied by Carbon Intensity, are 38,700,000 metric tons of $CO_2$ in the year 2025.

The SCC if these emissions occur each year for the decade of 2020 thru 2029 is estimated to be:

(5 years * 38,700,000 metric tons/year * $46/metric ton) +

(5 years * 38,700,000 metric tons/year * $50/metric ton) = $ 18.6 billion

- SCC = $18.6 billion for emissions occurring over the decade of 2020 to 2029

**Scenario 4: Single Plant Retirement - Clean Power Plan, 111(d) Compliance**

This scenario assumes 9% of the nuclear generation capacity is retired and replaced by a generation mix that complies with the federal Clean Power Plan. As previously explained, Illinois will need to implement measures that require a cleaner generation mix beginning in 2020. Illinois' fossil fuel-fired generation sources will go from a current emission rate of 2,189 pounds of $CO_2$ per MWh to a final target of 1,271 pounds of $CO_2$ per MWh or equivalent by 2030. Furthermore, RE generation may more than double under 111(d) from the current 4% to around 9% of total generation. EE measures are also expected to significantly increase in Illinois, although they may be offset by growth in generation demand.

<u>Replacement Generation Mix:</u>

- Fossil fuel-fired (e.g., coal and natural gas) in compliance with 111(d): 91%
- RE: 9%

The SCC for the years 2020 thru 2024 is estimated to be $46 per metric ton, and $50 for the years 2025 thru 2029.

The Carbon Intensity of the replacement generation mix is 0.58 metric tons per MWh – converted from the compliance rate of 1,271 pounds of $CO_2$ per MWh.

Generation of 9,000,000 MWh at an average Carbon Intensity of 0.58 metric tons per MWh results in 5,220,000 metric tons of $CO_2$ emissions each year.

The total present Social Cost of these additional emissions in the decade of the 2020's are estimated to be:

(5 years * 5,220,000 metric tons * $46/metric ton) +

(5 years * 5,220,000 metric tons * $50/metric ton) = $2.5 billion

- SCC = $2.5 billion for emission occurring over the decade of 2020 to 2029

**Summary of Societal Cost Carbon Estimates**

The SCC estimates for the scenarios examined range from $2.5 to $18.6 billion for emissions occurring over the decade of 2020 to 2029. The total SCC associated with nuclear plant closures is dependent upon the timing and amount of generation retired, and the carbon intensity of the mix of generation sources that replace the lost nuclear generation.

**Potential Nuclear Power Plant Closings in Illinois**

Economy, Jobs and the environment

CHAPTER 4. ILLINOIS DEPARTMENT OF COMMERCE AND ECONOMIC OPPORTUNITY'S RESPONSE

***RESOLVED, That we urge the Department of Commerce and Economic Opportunity to prepare a report showing how the premature closure of existing nuclear power plants in Illinois will affect jobs and the economic climate in the affected areas;***

# ILLINOIS DEPARTMENT OF COMMERCE AND ECONOMIC OPPORTUNITY'S RESPONSE

## Economic Impact Evaluation

### Executive Summary

The maintenance and development of low or no carbon emissions energy assets coupled with low and stable electricity prices are critical to Illinois' continued economic recovery. Historically, Illinois' status as a net regional exporter of electricity has yielded some of the region's lowest and most stable electricity prices which, in turn, has helped Illinois retain and build industrial and commercial-based economic development. Since 2009, Illinois' net export of electricity is estimated to average about twenty-five percent annually or close to 50 terawatt-hours (TWh)[113]. The fact that Illinois is a net exporter of energy is significant and acts as a key asset to maintain for the following reasons: (1) low and stable electricity prices, (2) provides approximately $1,688,412,000[114] in revenue annually to Illinois' economy and (3) attracts energy-intensive industries to locate within Illinois. These positive results are due in large part to the investments that Illinois utilities and consumers made in several nuclear power plants located throughout Illinois.

The value of Illinois continuing to be a net exporter of electricity both now and in the future is an underlying impetus of House Resolution 1146 (HR 1146). If Illinois is to continue as a net exporter of energy under the USEPA proposed carbon dioxide reduction rule Illinois will have to act to maintain existing low or no carbon emissions energy assets as well as develop new low or no carbon emissions energy assets. Electricity in Illinois is generated from the following resources[115]: Nuclear 48%; Coal 43%, Renewable Energy 4.8%, Combined Cycle Natural Gas2.2%, Gas/Other .6% and Hydropower .03%. The USEPA's rule will reduce national reliance on coal, creating a new regime of opportunity. States that act proactively to encourage and maintain low or no carbon emissions energy assets will be in the best position to maintain low electricity prices and sustain economic development as net exporters of energy. The State of Illinois has the largest reserves of bituminous coal in the U.S. making low carbon emitting generation from coal a high priority for the state. In addition, much of the State of Illinois overlays the Mount Simon Sandstone. This is a saline filled, porous deep geological formation of enormous capacity that has been determined to be one of the most significant carbon storage resources in the U.S. The successful development and implementation of CCS provides the state with a key competitive advantage in being able to lead the U.S. and the world in strategies for continued use of coal in an environmentally acceptable manner.

Wholesale electric market conditions have been challenging for Illinois' nuclear power plants over the past several years. These challenges have been driven largely by historically low

[113] See Figure 19

[114] 51,164,000 MWh (see Figure 19) * $33/MWh (average of projected market prices going forward on Figure 23) = $1,688,412,000

[115] See Figure 20

wholesale market prices for electricity. While competitive wholesale electricity markets do yield benefits to Illinois, they also fail to fully compensate nuclear plant operators for the value they provide to the market. For instance, nuclear power plant operators do not receive adequate incentives for the nearly uninterrupted flow of power that they provide – even though it was nuclear power plants like those in Illinois that prevented blackouts during last winter's polar vortex. Also, nuclear power plant operators do not receive adequate incentives for emitting no carbon pollution.

These market shortcomings have undermined the revenue streams that are necessary to support all of the nuclear power plants currently operating in Illinois. Exelon has recently indicated that as many as three (3) of their Illinois-based nuclear power plants may have to be retired in the near term unless additional incremental revenues can be captured to support plant operations.

In summary, this report makes the following findings and recommendations:

**Significant Negative Economic Impact.** The negative economic impacts resulting from the early retirement of Byron, Clinton, and Quad Cities nuclear generating stations are considerable:

- **2,500 direct job losses at the nuclear plants;**
- **4,431 indirect job losses at local businesses that do business with the plants;**
- **$1.8 billion in annual lost economic activity for the state of Illinois; and,**
- **10-16% increase in wholesale power prices which will cause another 896 job losses and cost the state another $45 million in lost economic activity.**

**Economic Losses can be Mitigated.** The near-term negative economic impacts resulting from the early retirement of at-risk nuclear assets can be mitigated through investments in energy efficiency and renewable energy resources:

- **9,600 new jobs can be created by 2019;**
- **$120 million in annual energy cost savings due to lower market prices for electricity;**

Illinois' continued economic success depends on maintaining low and stable electricity prices – and those low and stable prices depend on the continued operation of all nuclear generating stations located in Illinois. Eventually, market forces and national policies will fully compensate nuclear plant operators for their reliability and carbon-free emissions. Until that time, Illinois has the opportunity to craft effective market-based solutions that can support all forms of low carbon power generation to be sited in Illinois for the benefit of Illinois' economy and citizens.

### Background

The state of Illinois is ranked 5th in electricity generation and 9th in electricity consumption within the US[116]. Illinois operates as a net exporter of electricity in the Midwest region. The fact that Illinois is a net exporter of energy is significant and acts as key asset to maintain for the

[116] Energy Information Administration, US Department of Energy, State Energy Profiles: Illinois

following reasons: (1) low and stable electricity prices, (2) provides approximately $1,688,412,000[117] in revenue annually to Illinois' economy and (3) attracts energy-intensive industries to locate within Illinois. Since 2009, Illinois' net export of electricity is estimated to have averaged about 25 percent, or close to 50 terawatt-hours (TWh)[118].

The value of Illinois continuing to be a net exporter of electricity both now and in the future is the impetus of House Resolution 1146 (HR 1146). If Illinois is to continue as net exporter of energy under the U.S. Environmental Agency's (EPA) proposed carbon dioxide reduction rule that will take effect in June 2015, Illinois will have to act to maintain existing clean energy assets as well as develop new clean energy assets. Electricity in Illinois is generated from the following resources[119]: Nuclear 48%; Coal 43%, Renewable Energy 4.8%, Combined Cycle Natural Gas2.2%, Gas/Other .6% and Hydro .03%. The EPA's rule will reduce national reliance on coal, creating a new regime of opportunity. States that act proactively to encourage and maintain clean energy assets will be in the best position to maintain low electricity prices and sustain economic development as net exporters of energy.

Exelon Corporation ('Exelon') is an energy holding company that is headquartered in Chicago, Illinois and reported $25 billion in operating revenues for fiscal year 2013. Exelon is engaged in electricity generation through its Exelon Generation Company, LLC subsidiary which is comprised of two primary business units – Exelon Nuclear and Exelon Power. Exelon Nuclear operates a fleet of twenty-three (23) reactors at fourteen (14) locations throughout Illinois, Maryland, Nebraska, New York, New Jersey and Pennsylvania. Exelon Nuclear assets located in Illinois and their associated commissioning dates are noted in Figure 1 (gray shaded cells indicate assets that have ceased electricity generation operations).

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[117] 51,164,000 MWh (see Figure 19) * $33/MWh (average of projected market prices going forward on Figure 23) = $1,688,412,000

[118] See Figure 19

[119] See Figure 20

**Figure 1: Exelon Nuclear Assets in Illinois**

| Exelon Nuclear Asset | County Location | Number Reactors | Commissioning Date / License Expiration Date / Generating Capacity |
|---|---|---|---|
| Braidwood Nuclear Generating Station | Will | 2 | Unit 1: 1988 / 2026 / 1,178 MW |
| | | | Unit 2: 1988 / 2027 / 1,152 MW |
| Byron Nuclear Generating Station | Ogle | 2 | Unit 1: 1985 / 2024 / 1,164 MW |
| | | | Unit 2: 1987 / 2026 / 1,136 MW |
| Clinton Nuclear Generating Station | DeWitt | 1 | Unit 1: 1987 / 2026 / 1,065 MW |
| Dresden Nuclear Power Plant | Grundy | 3 | Unit 1: 1960 / Decommissioned |
| | | | Unit 2: 1970 / 2029 / 867 MW |
| | | | Unit 3: 1971 / 2031 / 867 MW |
| LaSalle County Nuclear Generating Station | LaSalle | 2 | Unit 1: 1982 / 2022 / 1,118 MW |
| | | | Unit 2: 1984 / 2023 / 1,120 MW |
| Quad Cities Nuclear Generating Station | Rock Island | 2 | Unit 1: 1972 / 2032 / 908 MW |
| | | | Unit 2: 1972 / 2032 / 911 MW |
| Zion Nuclear Generating Station | Rock Island | 2 | Unit 1: 1973 / Decommissioned |
| | | | Unit 2: 1974 / Decommissioned |
| | Indicates decommissioned nuclear generation reactors | | |

Exelon Nuclear sells electricity, capacity and ancillary services into regional wholesale electricity markets at prevailing markets rates (as opposed to regulated cost of service based rates) under market-based rate authorization granted by the Federal Energy Regulatory Commission (FERC) under Order No. 697. FERC grants market-based rate authorization is to electricity sellers that can demonstrate that they and their affiliates have mitigated horizontal and vertical market power.

Exelon Nuclear's Illinois-based assets sell electricity products and services into two regional wholesale markets: PJM Interconnection, LLC ('PJM') and Midwest Independent System Operator ('MISO'). Exelon Nuclear's Braidwood, Byron, Dresden, LaSalle, and Quad Cities generating stations operate in the PJM wholesale market while the Clinton generating station operates within the MISO wholesale market. Market-based prices for electricity, capacity, and ancillary services are set within PJM and MISO through competitive auction processes where every energy provider submitting bids that clear in the auction processes receives the market-clearing price for their outputs.

Market-based prices for electricity, capacity, and ancillary services have trended downward in recent years resulting in reduced revenue for Exelon's nuclear assets. The loss in revenue has prompted Exelon Corporation to consider retiring as many as three (3) of its Illinois-based nuclear assets (Byron, Clinton, and Quad Cities)[120] and as such serves as the basis for our economic impact analysis.

120 "Exelon Warns State it may Close 3 Nukes", Crain's Chicago Business, March 3, 2014

This report represents the response by the Illinois Department of Commerce and Economic Opportunity ('Department') to the following specific actions contained within HR 1146:

> *"RESOLVED, That we urge the Department of Commerce and Economic Opportunity to prepare a report showing how the premature closure of existing nuclear power plants in Illinois will affect jobs and the economic climate in the affected areas; and be it further*

In response to the House Resolution, the Department assembled a team of internal and external experts to conduct the analysis required to perform the tasks assigned by HR 1146. The project team included academics from Northern Illinois University and Illinois State University, and staff from the Department's Office of Coal Development and Bureau of Energy and Recycling. The Project Team arranged its work into two primary initiatives: Economic Impact Studies and Market Solution Development. Overviews of the two initiatives are provided below.

**Approach to Evaluating Economic Impacts.**

Economists from Northern Illinois University Center for Governmental Studies and Illinois State University Center for Renewable Energy were tasked to assess the primary and secondary economic impacts of the early retirements of the three targeted nuclear plants. Primary economic impact was evaluated in the areas of Employment, Labor Income, and Value-Added economic activity.. Secondary economic impact was evaluated in the area of electricity price impact resulting from the loss electricity generation outputs within the state. The project team utilized inputs from a variety of sources to project the economic impact of the early retirement scenario including:

- **IMPLAN (IMpact analysis for PLANning).** The IMPLAN software platform is a widely-accepted and utilized software model that utilizes a proven input-output dollar flow analysis. Using this input-output analysis, IMPLAN models the way a dollar injected into one sector is spent and re-spent in other sectors of the economy, generating waves of economic activity, or so-called "economic multiplier" effects. The model uses national industry data and county-level economic data to generate a series of multipliers, which in turn estimate the total economic implications of economic activity. For the purposes of this analysis, IMPLAN simulations were conducted for both county and statewide level to model the economic results of the two scenarios.
- **Aurora (Aurora XMP).** Aurora is a commercially-available electric power market forecasting tool that simulates the operations of each power market in the continental U.S. The Aurora model optimizes dispatch by using the lowest cost resources to meet electricity demand in a given region at the hourly level and builds the most economic new resources to backfill for retirements and meet future load growth. Aurora is typically used to support resource planning, regulatory analysis, commodity price forecasting, and asset valuation. Both IMPLAN and Aurora seek to determine the least-cost method to meet electricity demand given various exogenous inputs and constraints.
- **JEDI (Jobs and Economic Development Impact).** The JEDI model was developed by the National Renewable Energy Laboratory and is an input-output model that estimates the economic impact of constructing and operating energy infrastructure. JEDI studies are based on user-entered project-specific data or default inputs for a wide range of power generation technologies, as well as biofuels production and the construction of transmission lines. JEDI can generate estimates for the number of direct, indirect and induced effects in

two categories: economic activity within the region of interest, and number of jobs supported.

- **NEI Report.** The Project Team also evaluated a report by the Nuclear Energy Institute ("The Impact of Exelon's Nuclear Fleet on the Illinois Economy: An Analysis by the Nuclear Energy Institute", October 2014) that projected significant annual lost economic output in Illinois by 2020 in the event of the retirement of the targeted plants. The Project Team identified multiple inconsistencies within the NEI report that call into question the accuracy of the report's conclusions.
- **Exelon-sourced Data.** The Project Team requested and received from Exelon certain data concerning the expenditures incurred by their Illinois-based nuclear assets.

### Economic Impact Evaluation

- Retiring the three targeted Exelon's nuclear assets presents net short-term economic challenges for Illinois:
  - ✓ 2,500 direct job losses at the nuclear plants
  - ✓ 4,431 indirect job losses
  - ✓ $1.8 billion in reduced economic activity
- Early retirement of Illinois' at-risk nuclear assets will likely cause low to moderate increases in electricity costs over the near term.
- Job losses and electricity price increases can be largely mitigated by fully developing energy efficiency and renewable energy resources.

Nuclear power assets are integral parts of their host communities and provide real economic benefits. Expenditures with local suppliers, direct and indirect jobs, tax revenues, and other contributions to local economies make nuclear generating stations some of the most valued economic assets in Illinois.

Capturing the entirety of all economic activity resulting from the operation of Illinois' nuclear assets is challenging. The Department's evaluation manages to identify the majority of primary and secondary economic activity; however, due to a lack of comprehensive historical data the evaluation likely produces conservative results. For instance, the Department was unable to perform a detailed economic evaluation of the economic activity resulting from the plant upgrades and unit refueling activities undertaken by Exelon at their Illinois-based assets. During such events, many out-of-state contractors take short-term residency in the local areas surrounding the nuclear asset and spend money for lodging, rentals, retail goods, food services, and gasoline. And although there is generally a reduction in electricity generated during these activities, local economic activity likely increases dramatically.

The Department's analysis is focused on the short term due to the following relevant factors:

- **Potential Relicensing.** Exelon operates its nuclear assets subject to licenses issued by the Nuclear Regulatory Commission (NRC). NRC licenses are granted for finite periods, and Exelon is not required to request for license extensions, nor is the NRC required to grant extensions. Given the uncertainties around license extensions for the nuclear assets, the Department has focused its analysis on the near term period (2015-2020).
- **Regulatory Changes.** Section 111, 42 U.S.C. §7411, of the Clean Air Act requires the USEPA to develop regulations to reduce carbon dioxide pollution from existing coal power plants. The new rule, that will take effect in June 2016, requires states to meet individual

carbon dioxide pollution goals. Each state will be required to submit a compliance plan to the USEPA. Illinois' own Section 111(d) plans are to be completed by June 30, 2016 with compliance with that plan to begin in 2020. As with the relicensing, the uncertainties around 111(d) regulations have led the Department to focus its analysis on the period prior to 2020.

The Department's analysis projects the net economic effects of primary and secondary economic impacts resulting from the early retirement of at-risk nuclear assets. Primary economic impact was measured in the categories of Employment, Labor Income, and Value-Added economic activity at the local and state level. Secondary economic impact was evaluated with regard to how the early retirement of the at-risk nuclear assets could affect electricity prices within the state. Figure 2 conveys the issues matrix used for the Economic impact evaluation.

**Figure 2: Potential Impacts Related to Early Nuclear Asset Retirement in Illinois**

| Comparison Categories | Description of Variables Considered in the Scenario Analyses | |
|---|---|---|
| | Primary Economic Impact | Secondary Economic Impact |
| Value-Added Economic Activity | Net economic activity resulting from the lost revenues and expenditures when operations cease due to early retirement. | Net impact on economic activity resulting from higher electricity prices attributable to early nuclear asset retirement. |
| Employment | Net direct and induced job losses resulting from the closure of the at-risk nuclear assets. | Net job losses resulting from marginally higher electricity costs resulting from closure of the at-risk nuclear assets. |
| Labor Income | Net direct and induced reductions in payrolls resulting from the closure of the at-risk nuclear assets | Net direct and induced reductions in payrolls resulting from lost employment resulting from higher electricity costs. |
| Energy Sector Development | Net direct and induced increases in economic activity related to increased development of energy generation resources to replace lost generating capacity resulting from early retirement of at-risk nuclear assets. | - |

**Primary Economic Impact Analysis.**

The Project Team used the industry-standard IMPLAN 3 software and databases to estimate the potential economic impact of the retirement of three nuclear generating stations located in Illinois (Byron, Clinton, and Quad Cities). IMPLAN was originally developed by the U. S. Department of Agriculture's Forest Service, the Federal Emergency Management Agency, and the U. S. Department of Interior's Bureau of Land Management. The model was initially used to assist in land and resource management planning and has been in use since 1979. Currently, the model is supported by the Minnesota IMPLAN Group, Inc.

IMPLAN operates from the perspective of an input-output economic model. Input-output models link various sectors of the economy (e.g. agriculture, construction, government, households, manufacturing, services and trade) through their respective spending flows in a reference year. These spending flows can be tracked between or within regions and at the national, state, or county levels.

By modeling these linkages, the impact of an economic event in any sector or geographic area on other sectors and areas can be modeled to identify the initial as well as secondary economic activity resulting from an economic event. In the case of an electric power plant, the initial economic activity would include the sale of electricity, capacity and ancillary services effects to the market, and secondary economic activity would include the subsequent economic activity resulting from how suppliers, employees, and owners of the power plant utilize their earnings that result from those initial sales.

Secondary economic activity falls into two categories - indirect and induced – which are modeled separately within input-output models. Indirect effects are those influencing the supply chain that feeds into the business in which the economic activity is located. For example, when a nuclear plant operator buys a computer for $1,000 it supports economic activity beyond the sale of electricity. As a result, the company that made the computer must increase its purchases of motherboards to maintain its inventory, increasing output in microchip industries. The microchip industries will then need to purchase more inputs for their production processes, and so on. The result will be an economic impact that is greater than the $1,000 initially spent for the computer.

Induced effects come from payments made to employees and subcontractors by the plant that lead to spending by local households. A portion of the $1,000 spent by the nuclear plant to purchase the computer goes to pay wages of employees at the company that made the computer. These wages will be used to support additional economic activity through household spending for goods and services.

The sum of the initial and secondary activity is referred to as "total effect", and the ratio of the total effect to the initial activity is referred to as the "multiplier effect". Multipliers can be developed for any industry/business sector or geographic area in the model. Multipliers for a county are smaller than for the state in which the county is located, because some spending associated with a local economic activity migrates from the local area into the larger region.

IMPLAN consists of two components: the software and the database. The software performs the necessary calculations, using the study area data, to create the models. It also provides an interface for the user to change the region's economic description, create impact scenarios and introduce changes into the local model. The IMPLAN model's database and account structure closely follow the accounting conventions used in the input-output studies of the U.S. economy by the Department of Commerce's Bureau of Economic Analysis. The comprehensive and detailed data coverage of the entire United States by county, and the ability to incorporate user-supplied data at each stage of the model-building process, provides a high degree of flexibility in terms of both geographic coverage and model formulation.

**Economic Impact of Nuclear Asset Retirement.** Exelon operates six nuclear generating stations in Illinois. Three of these are under consideration for retirement in 2016: Byron, Clinton, and Quad Cities. These three plants report a total of 2,500 employees with a total payroll of about $350 million (Figure 3). In the aggregate, they purchase about $193 million worth of goods and services from other Illinois firms.

**Figure 3. Operating Expenditures of Exelon Nuclear Plants**

| Employment and Primary Expenditures for at-risk Exelon Nuclear Assets | | | | |
|---|---|---|---|---|
| Facility | Employees | Labor Spending | Goods Spending (excluding fuel) | |
| | | | Total | In Illinois |
| Byron Generating Station | 880 | $125,969,393 | $165,192,449 | $88,142,593 |
| Clinton Power Station | 711 | $97,275,730 | $86,230,570 | $49,643,597 |
| Quad Cities Generating Station | 909 | $127,958,448 | $124,078,051 | $55,355,746 |

Source: Exelon Corporation

Each of the at-risk nuclear assets is a significant employer within its region. Each employs hundreds of workers in well-paying jobs, averaging over $100,000 per year. The millions of dollars in purchases from each plant support hundreds of jobs across Illinois. The IMPLAN analysis examines the direct losses resulting from early retirement of these at-risk nuclear assets, and the indirect impacts of lost employee spending in the local economy as well as purchases the plants make within the state.

**Byron Generating Station.** The retirement of the Byron Generating Station is projected to result in the loss of almost 2,600 jobs in Illinois (Figure 4). Income associated with these jobs would be approximately $239 million. Value added economic activity (a measure similar to gross state product) would drop by $633 million in the state.

**Figure 4. Economic Impacts of Byron Generating Station Retirement**

| Economic Effects of Early Retirements for Byron Generating Station | | | |
|---|---|---|---|
| Economic Effect | Employment | Labor Income (in millions $) | Value Added (in millions $) |
| Direct Effect | -880 | -$126.0 | -$444.6 |
| Indirect Effect | -1,776 | -$113.3 | -$188.7 |
| Total Effect | -2,656 | -$239.3 | -$633.3 |

Source: CGS, IMPLAN 2014.

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**Clinton Power Station.** The retirement of Clinton Power Station is projected to result in an estimated loss of almost 1,900 jobs in Illinois (Figure 5). These jobs would be associated with about $165 million in income. The state would experience a loss of about $482 million in value added.

**Figure 5. Economic Impacts of Clinton Generating Station Retirement**

| Economic Effects of Early Retirements for Clinton Generating Station | | | |
|---|---|---|---|
| **Economic Effect** | **Employment** | **Labor Income (in millions $)** | **Value Added (in millions $)** |
| Direct Effect | -711 | -$97.3 | -$359.2 |
| Indirect Effect | -1,145 | -$68.2 | -$122.4 |
| Total Effect | -1,856 | -$165.5 | -$481.6 |

Source: CGS, IMPLAN 2014.

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**Quad Cities Generating Station**. The retirement of the Quad Cities Generating Stations is projected to result in the loss of more than 2,400 Illinois jobs (Figure 6). These jobs would have a total income of about $217 million. The loss of value added in the state would be more than $757 million.

**Figure 6. Economic Impacts of Quad Cities Generating Station Retirement**

| Economic Effects of Early Retirements for Quad Cities Generating Station | | | |
|---|---|---|---|
| **Economic Effect** | **Employment** | **Labor Income (in millions $)** | **Value Added (in millions $)** |
| Direct Effect | -909 | -$128.0 | -$608.2 |
| Indirect Effect | -1,510 | -$89.2 | -$149.1 |
| Total Effect | -2,419 | -$217.1 | -$757.3 |

Source: CGS, IMPLAN 2014.

**Aggregated Nuclear Plant Retirement Summary.** If the three nuclear plants are shut down, nearly 7,000 jobs may be lost in Illinois (Figure 7). Total lost labor income associated with those jobs losses would be approximately $620 million. Total value added in the state would be reduced by almost $1.9 billion.

**Figure 7. Economic Impacts of Retirement of all 'At-Risk' Exelon Nuclear Assets**

| Economic Effects of Early Retirements for all at-risk Generating Stations | | | |
|---|---|---|---|
| **Economic Effect** | **Employment** | **Labor Income (in millions $)** | **Value Added (in millions $)** |
| Direct Effect | -2,500 | -$351.2 | -$1,412.0 |
| Indirect Effect | -4,431 | -$270.7 | -$460.2 |
| Total Effect | -6,931 | -$621.9 | -$1,872.2 |

Source: CGS, IMPLAN 2014.

**Stabilizing Effects Following Large Local Employment Shocks.** Local economies that experience major employment losses such as those that are projected to occur with the retirement of the at-risk nuclear assets described above are clearly harmed in the short run.

Unemployment rises, incomes fall, and tax revenues decline. However, there are forces that tend to stabilize the local economy in the longer run.

The first force is migration. People tend to move or increase their commute for employment opportunities. As economic migration lowers the population in a region, the demand for public sector services is reduced. This will ease the burden faced by governments with declining tax revenues. The second stabilizing force is a change in local price levels. As the demand for labor decreases, wage rates decline. Lower wage rates can attract new industries to the region and create new employment opportunities. Lower real estate prices resulting from out-migration can also attract new residents and entrepreneurs.

The immediate impacts of a major job loss can be serious, especially in a small community. In the long run there are factors that can lead to a healthy, though likely somewhat smaller, regional economy. Policies such as worker retraining programs can mitigate some of the negative impacts. Other measures that would mitigate the primary impacts of early retirement of at-risk nuclear assets over the near and longer term include the following:

**Nuclear Decommissioning.** Retired nuclear generating stations must be decommissioned according the requirements set by the Nuclear Energy Regulatory Commission. Decommissioning costs are estimated to range between $300 and $400 million per reactor.[121] According to the firm engaged by Exelon to decommission the nuclear reactors at the Zion Nuclear Generating Station, the realized cost of for decommissioning that asset's two reactors will be $1 billion[122], with "approximately $390 million in new economic output, 1,570 man-years of employment, and almost $150 million in employment compensation in Illinois"[123]. Decommissioning activities do not commence upon asset retirement and can extend well into the future. For this reason decommissioning activity and resulting economic impacts should be considered as a stabilizing factor over the long-term.

**Economic Impacts of Replacing Generating with Energy Efficiency.** In order for Illinois to maintain its electricity generating capacity levels, the electricity supply lost by the retirement of the nuclear plants will need to be replaced. One possible scenario to replace the electricity generated from retired nuclear assets is to maximize the use of energy efficiency and renewable energy within the state.

The Illinois Energy Efficiency Portfolio Standard (EEPS) was established in 2007 by the Illinois Power Agency Act and requires both electric and natural gas utilities to establish annual energy-savings goals to reduce energy consumption and peak demand. Utilities are required to file an energy efficiency and demand-response plan with the Illinois Commerce Commission every three years.

The electricity reduction goals apply to utilities that had 100,000 or more customers on December 31, 2005. The EEPS establishes an electricity savings goal of incremental annual sales reduction over the previous year's consumption, with a goal of a 2.0% reduction in

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121 Nuclear Regulatory Commission: www.nrc.gov/reading-rm/doc-collections/fact-sheets/decommissioning.html

122 http://insideclimatenews.org/news/20110613/decommissioning-nuclear-plant-can-cost-1-billion-and-take-decades

123 www.zionsolutionscompany.com/project/decommissioning/

electricity consumption by 2016 and every year thereafter. Additionally, utilities are responsible for implementing 75% of the energy efficiency measures approved by the ICC, and the DCEO is responsible for 25% of the measures by administering public sector and low income residential programs through *the Energy Efficiency Portfolio Standards (EEPS) Fund*. Utilities are responsible for collecting funds for measures implemented by the DCEO and transferring those funds directly to the DCEO.

The Illinois Energy Efficiency Stakeholder Advisory Group was established in the Final Orders approving the first three-year utility energy efficiency plans (February, 2008) by the ICC to review each utility's progress towards achieving its energy efficiency and demand response goals and to continue strengthening the portfolio of programs. The Stakeholder group's responsibilities include, but are not limited to: reviewing final program designs; establishing agreed-upon performance metrics for measuring portfolio and program performance; reviewing plan progress against metrics and against statutory goals; reviewing program additions or discontinuations; reviewing new proposed programs for the next program cycle; and reviewing program budget shifts between programs where the change is more than 20%.

Each utility has engaged third-party expert to evaluate the energy efficiency potential for their respective service regions, the Advisory Group reviews these "Potential Studies" and makes them available to the public on their website.[124] The Potential Study projects identify different categories of potential energy efficiency opportunities for the utilities: economic and technical potentials. Economic potential represents the adoption of the most efficient cost-effective measures where cost-effectiveness is established by the application of the Total Resource Cost (TRC) test, which compares the lifetime energy and capacity benefits to the incremental cost of an efficiency measure. Technical potential is defined as the theoretical upper limit of energy efficiency potential regardless of cost. Economic potential is the more conservative projection of potential energy efficiency opportunities.

The Department used the most current versions of the Potential Studies[125] to project the potential to which energy efficiency could offset energy generation and capacity lost to Illinois in the event the at-risk nuclear assets are retired. To account for the different time periods covered in each report, the Department used the following adjustments to establish a unified annual energy efficiency projection based on each Potential Study's assessment of economically viable energy efficiency:

- **ComEd.** The Department utilized the annual energy efficiency values reported as "Program Achievable" for the years 2016, 2017, and 2018 (the last year of the Potential Study's projections). Projections for years 2019, and 2020 were based on the average "Program Achievable" energy efficiency projections for the prior three (3) years.
- **Ameren.** The Department utilized the annual energy efficiency value reported as "Realistic Achievable" for the year 2016 (the last year of the Potential Study's

[124] http://www.ilsag.info/potential-studies.html

[125] Ameren Illinois Energy Efficiency Market Potential Assessment; Illinois Public Sector and Low-Income Housing Energy Efficiency Potential Study; ComEd Energy Efficiency Potential Study Report, 2013-2018.

projections). Projections for years 2017, 2018, 2019, and 2020 were based on the average of the 2016 "Realistic Achievable" and "Maximum Achievable" energy efficiency projections.

- **DCEO.** The Department utilized total annual energy efficiency values reported as "Economic Potential" for the entire six year period of the study divided by 6 years.

Figure 8 conveys the economically achievable energy efficiency for Illinois through the EEPS. The American Council for an Energy-Efficient Economy (ACEEE) provides an approach for estimating the employment impacts of improvements in energy efficiency[126]. Under this approach, as consumers spend less on utilities, that money is available to spend on goods and services in other sectors. This change in spending patterns has an impact on job creation.

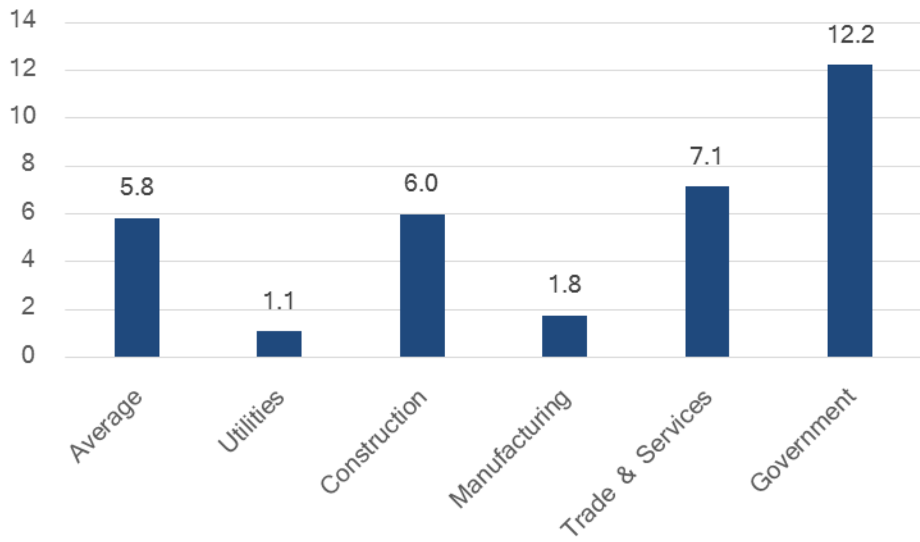
**Figure 8. Projected Buildup of Energy Efficiency Capacity to Replace Retired Nuclear Capacity**

| Projected Annual Economically Achievable Energy Efficiency (MWh) | | | | |
|---|---|---|---|---|
| **Year** | **ComEd** | **Ameren** | **DCEO** | **Subtotal** |
| 2016 | 749,000 | 320,000 | 643,937 | **1,789,537** |
| 2017 | 735,000 | 401,000 | 643,937 | **1,775,537** |
| 2018 | 609,000 | 401,000 | 643,937 | **1,649,537** |
| 2019 | 627,900 | 401,000 | 643,937 | **1,668,437** |
| 2020 | 627,900 | 401,000 | 643,937 | **1,668,437** |
| **Total** | **3,348,800** | **1,924,000** | **3,219,685** | **8,492,485** |
| Average Annual Energy Efficiency Savings (MWh) | | | | **1,698,497** |
| Average Annual Energy Efficiency Capacity Equivalent (MW) | | | | **215** |

Figure 9 illustrates the differences in job creation by sector. According to IMPLAN data for Illinois, for every $1 million in output in the utilities sector, about 1.1 jobs are supported. This is well below the average for all industries of 5.8 jobs per million dollars of output. The overall average for all non-utilities sectors is 5.9 jobs per million dollars. Thus, for each $1 million reduction in spending on utilities, and associated increase in spending in other sectors, just fewer than five jobs are generated.

[126] American Council for an Energy-Efficient Economy (2011). *How Does Energy Efficiency Create Jobs?* http://www.aceee.org/blog/2011/11/how-does-energy-efficiency-create-job

**Figure 9: Jobs per Million Dollars of Output by Key Sectors of the Illinois Economy**




Source: IMPLAN, 2014

Achieving a target level of annual energy efficiency increases of approximately 1.7 million MWh for the years between 2016 and 2020 would require an estimated investment of about $51.1 million (based on levelized costs)[127]. Figure 10 estimates the annual economic impacts of total statewide investments of this magnitude. <u>More than 650 jobs will result from these activities each year.</u>

**Figure 10. Estimated Annual Economic Impacts of Increased Energy Efficiency**

| Jobs Impact Projections | | | |
|---|---|---|---|
| **Economic Impact Categories** | **Employment** | **Earnings (in millions $)** | **Value Added (in millions $)** |
| Direct Effects | 339 | $22.8 | $25.1 |
| Indirect Effects | 315 | $17.5 | $29.7 |
| Total Effects | 168 | $40.3 | $54.9 |

Source: CGS, IMPLAN 2014.

Annual reductions in statewide energy use of 1.7 million MWh would save energy consumers about $18.3 million. Figure 11 displays the resulting annual employment impacts of this savings, using the ACEEE approach. For each $18.3 million that is moved from utilities spending to the remaining sectors of the Illinois economy, 88 additional jobs are supported. By 2020, about 440 new jobs are expected to be generated in Illinois.

[127] http://eetd.lbl.gov/news/article/57600/program-administrator-cost-of-s

**Figure 11. Estimated Employment Impacts of Energy Cost Savings**

| Jobs Impact Projections | | | | |
|---|---|---|---|---|
| Year | Cumulative Energy Savings (in millions $) | Cumulative Employment Impact | | |
| | | Non-Utilities | Utilities | Net |
| 2016 | $18.2 | 108 | -20 | 88 |
| 2017 | $36.5 | 215 | -39 | 176 |
| 2018 | $54.8 | 323 | -59 | 364 |
| 2019 | $73.1 | 431 | -79 | 352 |
| 2020 | $91.3 | 538 | -99 | 440 |

Source: CGS, IMPLAN 2014.

**<u>Economic Impacts of Replacing Generating with Renewable Energy.</u>** The two most likely sources of renewable energy in the State of Illinois are utility-scale wind energy and solar photovoltaics. In order to provide inputs into the economic dispatch model, the expected new capacity additions of wind and solar need to be determined. Illinois already has the fourth highest installed capacity of wind energy of any state but many more wind energy projects are in the development pipeline. Illinois has less solar capacity installed in the state but has a similar solar resource to New Jersey which has the second highest installed capacity of any state.

The Center for Renewable Energy at Illinois State University maintains a detailed database of wind farm projects in Illinois. The database includes wind energy projects that have been completed, are under construction, are permitted but not under construction, and proposed but not permitted. Specifics on each of the wind farms that that are in each category can be found at: http://renewableenergy.illinoisstate.edu/wind/databases.shtml.

A realistic estimate of the total new wind capacity that could be built in Illinois in the near term can be obtained by adding the total capacity of wind farms that have received permits in Illinois (3,300 MW) and the total capacity of wind farms that have been proposed but not yet permitted (7,578.10). The total capacity of permitted and proposed wind farms is assumed to be the total capacity built by 2020. Certainly some of the permitted and proposed wind farms will not be developed and certainly new projects will be proposed and built by 2020.

The Department uses a conservative approach and assumes that this is the total capacity in 2020 rather than the total capacity ADDED by 2020. In order to develop year-by-year forecasts, a linear progression was used to get from the current installed capacity (3569 MW in 2013) to this total capacity (10,878 MW) in 2020. This progression translates into 1,044 MW of wind capacity added per year. This trend would be a bit higher than our past experience in Illinois. Illinois installed 700-800 MWs of wind energy in 2007 and 2011. The linear progression would represent one to two wind farms higher than the previous best years of installation. This seems reasonable as a realistic best case for wind energy installation.

For solar capacity, the Center for Renewable Energy did a report titled *The Technical Potential for Solar in Illinois*[128] . This report shows that solar photovoltaics (PV) is capable of providing 2,714 MW of capacity assuming 100% of the electricity produced by PV is utilized. This capacity is only a slightly higher percentage (7.3%) than the current solar carve-out (6%).

Since this number represents the total capacity by 2025, the same linear progression was used for wind capacity, using 33 MW installed in 2013 growing to 2,714 MW by 2025. The progression translates into 223 MW of solar PV additions each year. Although Illinois has never installed that much solar PV, the total installed capacity is only slightly higher than the 6% solar carve-out required by 2025. Figure 12 provides the yearly installed capacity of wind and solar PV assumed in the model.

**Figure 12. Projected Buildup of Wind and Solar Capacity to Replace Retired Nuclear Capacity**

| Annual Forecast of Renewable Energy Capacity Additions to Replace Nuclear Closures | | |
|---|---|---|
| **Year** | **Wind Capacity (MW)** | **Solar Capacity (MW)** |
| 2013 | 3569 | 33 |
| 2014 | 4613 | 256 |
| 2015 | 5657 | 480 |
| 2016 | 6701 | 703 |
| 2017 | 7746 | 927 |
| 2018 | 8790 | 1150 |
| 2019 | 9834 | 1374 |
| 2020 | 10878 | 1597 |
| | | |
| | Linear growth 2014-2020 | Linear growth 2014-2025 |
| Annual additions | 1044 | 223 |

Results from an electricity dispatch model indicate that additional capacity of 6,318 MW in renewable energy generations is expected to be added between 2016 and 2020 or about 1,264MW per year[129]. Renewable projects will be a mix of wind (~82%) and solar (~18%)[130].

The economic impacts of increased renewable energy capacity are estimated using the Jobs and Economic Development Impact (JEDI) models developed by the National Renewable Energy Laboratory. Based on user-entered project-specific data or default inputs (derived from industry norms), JEDI estimates the number of jobs and economic impacts to a

128 http://renewableenergy.illinoisstate.edu/downloads/publications/2013SolarReport.pdf

129 Source: EVA modeling results

130 Source: Illinois State University Center for Renewable Energy

local area that can reasonably be supported by a power plant, fuel production facility, or other project. Jobs, earnings, and output are distributed across three categories:

- Project Development and Onsite Labor Impacts
- Local Revenue and Supply Chain Impacts
- Induced Impacts

JEDI model defaults are based on interviews with industry experts and project developers. Economic multipliers contained within the model are derived from Minnesota IMPLAN Group's IMPLAN accounting software and state data files[131].

*Wind Generation Capacity.* According to the projections, just over 1 gigawatt (1,036 MW) of wind generation capacity is expected to be brought on line each year from 2016 through 2020. Construction of the generation units would occur in the year leading up to the initial power generation. Economic impacts will result from both the construction and the operation of the additional units.

Figure 13 displays the construction and operating cost assumptions associated with an additional 1,036 MW in wind generation capacity. The cost estimates were generated using the default values in the JEDI model. It is estimated that the total installed cost would be just over $2.1 billion with about $470 million of that amount spent in Illinois. Once complete, the annual operating cost would be about $339 million.

131 Source: National Renewable Energy Laboratory (2014). *About JEDI Models*. www.nrel.gov/analysis/jedi/about_jedi.html

**Figure 13. Estimated Costs Associated with Additional Wind Generation Capacity**

| JEDI Model Inputs and Outputs for Specified Wind Energy Investments | |
|---|---|
| Project Location | ILLINOIS |
| Year of Construction | 2015 |
| Total Project Size - Nameplate Capacity (MW) | 1,036 |
| Number of Projects (included in total) | 1 |
| Turbine Size (kW) | 2000 |
| Number of Turbines | 518 |
| Installed Project Cost ($/kW) | $2,050 |
| Annual O&M Cost ($/kW) | $21 |
| Money Value (Dollar Year) | $2,012 |
| Total Installed Project Cost | $2,124,125,901 |
| Local Spending | $469,447,549 |
| Total Annual Operational Expenses | $339,040,191 |
| Direct Operating and Maintenance Costs | $21,577,026 |
| Local Spending | $6,460,141 |
| Other Annual Costs | $317,463,165 |
| Local Spending | $11,113,426 |
| Debt and Equity Payments | $0 |
| Property Taxes | $7,148,400 |
| Land Lease | $3,108,000 |
| | |

Source: CGS, NREL JEDI model 2014.

The installation of additional wind turbines with a total capacity of 1,036 MW are expected to create almost 4,700 jobs (Table 7). Most of these jobs will be created in the industries that supply the turbines and related machinery required for the installation. More than 1,500 jobs will be created by construction and supplier workers spending their income in the local economy (induced impacts). Total earnings resulting from this economic activity is expected to be more than $300 million. These impacts will occur annually for five years as a total wind generation capacity of 5,180 MW is installed.

Once construction is complete, the operation and maintenance of the turbines will generate economic impacts. Employment in Illinois is expected to grow by almost 170 jobs as a result of the turbine operations and maintenance. These jobs will have associated earnings of about $10.9 million.

These impacts are annual and will continue into the future. As more generating capacity is added each year, these impacts will grow proportionally. In 2017, a total of 2,072 MW of generating capacity is expected to be operating, twice the level of 2016. Thus, employment impacts will be about 336 jobs with earnings of $21.8 million. By the time the wind generating capacity is fully built out to 5,180 in 2020, the annual economic impacts are expected to rise to 840 jobs with $54.5 in earnings.

*Solar Generation Capacity.* About 1,140 MW of solar generation capacity is expected to be needed by 2020 in response to the retirement of the three nuclear plants. Similar to the wind generation capacity, construction of the solar units would occur in the year leading up to the initial power generation. Economic impacts will result from both the construction and the operation of the additional capacity and are conveyed in Figure 14. Solar capacity will be 60% utility scale; 20% large commercial; 10% small commercial and 10% residential[132].

**Figure 14. Estimated Annual Impacts of Wind Generation Operations (1,036 MW)**

| Jobs Impact Projections Resulting from Wind Energy Investment | | |
|---|---|---|
| **Job Impact Categories** | **Jobs** | **Earnings (in millions $)** |
| Onsite Labor Impacts | 47 | $3.5 |
| Local Revenue and Supply Chain Impacts | 60 | $3.8 |
| Induced Impacts | 60 | $3.6 |
| Total Impacts | 168 | $10.9 |

Source: CGS, NREL JEDI model 2014.

Economic impacts associated with the installation and operation of solar generating capacity were also estimated using the NREL JEDI model. Figure 15 displays the total economic impacts that are expected to accrue over the five years of installation. More than 17,500 job-years are expected to be supported by the installations, an average of 3,500 per year. Total earnings are expected to approach $1.1 billion (and average of $219 million per year).

132 Source: Illinois State University Center for Renewable Energy

**Figure 15. Estimated Costs Associated with Additional Solar Generation Capacity**

| JEDI Model Inputs and Outputs for Specified Solar Energy Investments | | |
|---|---|---|
| **Economic Activity Categories** | **Job Years** | **Earnings (in Millions $)** |
| Project Development and Onsite Labor Impacts | | |
| Construction and Installation Labor | 2,288 | $277.8 |
| Construction and Installation Related Services | 3,863 | $253.7 |
| Subtotal | 6,151 | $531.4 |
| Module and Supply Chain Impacts | | |
| Manufacturing Impacts | 0 | $0.0 |
| Trade (Wholesale and Retail) | 1,376 | $78.0 |
| Finance, Insurance and Real Estate | 0 | $0.0 |
| Professional Services | 561 | $31.1 |
| Other Services | 1,637 | $155.8 |
| Other Sectors | 3,000 | $78.3 |
| Subtotal | 6,574 | $343.1 |
| Induced Impacts | 4,800 | $220.2 |
| Total Impacts | 17,525 | $1,094.7 |
| Average Annual Impacts | 3,505 | $218.9 |

Source: CGS, NREL JEDI model 2014.

As shown in Figure 16, the JEDI model projects the impacts of the solar installations to increase steadily over the five year period. While the average employment impact is about 3,500 jobs per year, estimated job creation is significantly higher in later years. Over half of the installation impacts are expected to occur in 2018 and 2019. Solar installations at utilities will generate about 40% of the employment impacts.

**Figure 16. Estimated Annual Employment Impacts of Solar Generation Installation**

| Jobs Resulting from Investments in Solar | | | | | | |
|---|---|---|---|---|---|---|
| **Impact Categories** | **2015** | **2016** | **2017** | **2018** | **2019** | **Cumulative** |
| Total Impacts | 2,113 | 2,652 | 3,329 | 4,180 | 5,251 | 17,525 |
| Residential | 404 | 503 | 626 | 778 | 968 | 3,278 |
| Small Commercial | 338 | 420 | 522 | 649 | 806 | 2,735 |
| Large Commercial | 565 | 697 | 860 | 1,062 | 1,310 | 4,494 |
| Utilities | 805 | 1,032 | 1,321 | 1,692 | 2,168 | 7,018 |

Source: CGS, NREL JEDI model 2014.

Once fully operational in 2020, solar generation activities (residential, commercial, and utilities) are expected to generate 113 jobs. These jobs would have earnings of more than $11 million. These will be ongoing, annual impacts.  Figure 17 displays the jobs impact of the specified solar investments.

**Figure 17. Estimated Economic Impacts of Solar Generation Operations**

| JEDI Model Inputs and Outputs for Specified Solar Energy Investments | | |
|---|---|---|
| **Economic Activity Categories** | **Job Years** | **Earnings (in Millions $)** |
| Onsite Labor Impacts | | |
| PV Project Labor Only | 71 | $8.5 |
| Local Revenue and Supply Chain Impacts | 20 | $1.4 |
| Induced Impacts | 22 | $1.2 |
| Total Impacts | 113 | $11.2 |

Source: CGS, NREL JEDI model 2014.

Figure 18 displays the annual estimated employment impacts of the potential nuclear plant retirement and related wind and solar capacity development. Job gains are strong in the early years as construction of the wind and solar infrastructure takes place. However, nuclear power generation requires more jobs per unit of output than renewable energy sources. Once wind and solar installations are complete in 2020, net job losses will total 5,539.

**Figure 18:  Summary of Annual Employment Impacts**

| Net Annual Job Impact of Offset Investments in Wind and Solar | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Power Technology** | **Job Categories** | **Year** | | | | | |
| | | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| Wind | Construction | 4,672 | 4,672 | 4,672 | 4,672 | 4,672 | |
| | Operations | | 168 | 335 | 504 | 672 | 840 |
| | Total | 4,672 | 4,840 | 5,008 | 5,176 | 5,344 | 840 |
| Solar | Construction | 2,113 | 2,652 | 3,329 | 4,180 | 5,251 | |
| | Operations | | 12 | 28 | 49 | 77 | 113 |
| | Total | 2,113 | 2,664 | 3,357 | 4,230 | 5,328 | 113 |
| Efficiency | Total | | 88 | 176 | 264 | 352 | 440 |
| Nuclear | Total | | -6,931 | -6,931 | - 6,931 | -6,931 | -6,931 |
| Net | Total | 6,785 | 661 | 1,610 | 2,738 | -4,093 | -5,539 |

**Conclusions.** The primary economic impacts related to the potential retirement of Illinois' at-risk nuclear assets are significant. However, much of the immediate negative economic impact can be mitigated through a concerted initiative to fully-develop all economically viable energy efficiency and potential wind and solar resources.

**Secondary Economic Impact Analysis.**

The state of Illinois has two separate centrally dispatched power markets operating within its borders: the PJM Interconnect (PJM) in the north and the Midcontinent ISO (MISO) in the south. In the north, the major utility Commonwealth Edison[133] is a member of PJM and serves customers in Chicago and the surrounding region. The major utility in the south is Ameren[134], a member of MISO. A map of Illinois showing the borders of each power market is provided in Appendix I of this report. Each of these grid operators is tasked with coordinating the movement and sale of wholesale energy and capacity in their respective territories as well as establishing rules that promote competition. Because Illinois is connected to two separate power grids, any change to the state's system, such as capacity retirements, will affect operations in both markets.

**Modeling Methodology.** Electricity costs are minimized by operating generators based upon their variable operating costs subject to operating and transmission constraints. Generators that are members of RTOs largely cede operating decisions to its RTO which in turn "dispatch" member capacity in the least cost manner. As a result, any forecast of future power market outcomes must similarly dispatch generating capacity in a manner consistent with either the respective RTO or the entity dispatching each plant using an hourly economic dispatch model. Dispatch models are also used for planning purposes, power price forecasting, and risk analysis. Capacity modules are run to determine least cost capacity decisions regarding retirements and additions in the context of required reserve margins.

The AuroraXMP dispatch model was used for forecasting the cost impacts resulting from the early retirement of Illinois' at-risk nuclear assets. The model analyzes North American electric power markets on an 8760 hourly basis, consistent with real world power pool dispatch operations. Dispatch models are data intensive requiring information about all existing power operations as well as information on relative costs and operating characteristics of existing capacity, relative capital and operating costs of new capacity, plant retirements, delivered fuel price information, transmission capacity, electricity demand growth, and environmental requirements including renewable standards. Many of the data inputs have been customized to reflect analysis of industry behavior as well as to improve the quality of the results.

**Analysis.** Aurora XMP was used to evaluate the impact of a year-end 2016 retirement of a total of five nuclear reactors at Byron (two units), Clinton (one unit), and Quad Cities (two units) on the level, mix, and wholesale cost of generation in Illinois through 2019. The Clean Power Plan is not expected to take effect until after 2019 and is outside the evaluation period. Given the complexity of the Clean Power Plan proposal, the concerns raised by many regarding the impact on system reliability and costs, and USEPA's own announcements regarding its plans to modify

[133] Now part of Exelon

[134] Ameren generating units in Illinois owned by Dynegy

the proposal, DCEO decided such an analysis inclusive of Clean Power Plan impacts could be misleading as the final rule may be materially different from the one proposed.[135]

Market price modeling utilized standard assumptions in addition to specialized forecasts for renewable energy and energy efficiency development.

**Results.** As shown in Figure 19, over the last five years, power generating assets in Illinois have generated between 191,000 and 200,000 GWh per year. Given in-state demand, net exports are estimated to have averaged about twenty-five percent, or close to 50 terawatt-hours (TWh). The three at-risk nuclear assets produced roughly 42 TWh annually.

**Figure 19: Historical Illinois Electricity Generation, Sales, and Net Exports**

| | In-State Gen (GWh) | Elec Sales (GWh) | Demand + Losses (GWh)* | Net Exports (GWh) | Net Exports (% Total Gen) |
|---|---|---|---|---|---|
| **2009** | 191,073 | 136,681 | 143,515 | 47,558 | 25% |
| **2010** | 198,174 | 144,378 | 151,597 | 46,577 | 24% |
| **2011** | 196,237 | 141,955 | 149,053 | 47,184 | 24% |
| **2012** | 194,478 | 143,540 | 150,717 | 43,761 | 23% |
| **2013** | 199,799 | 141,557 | 148,634 | 51,164 | 26% |

Source: EIA 923, EIA 714, EVA analysis

The largest source of in-state generation has been nuclear, typically providing about fifty percent of total statewide generation. Coal accounts for most of the remainder with combined cycle gas turbines (CCGT), renewables and other providing the rest. (Figure 20)

**Figure 20: Historical Illinois Electricity Generation by Fuel Type (GWh)**

| | Coal | CCGT | Nuclear | Gas Other | Other | Hydro | Renewable |
|---|---|---|---|---|---|---|---|
| **2009** | 88,385 | 2,843 | 95,474 | 712 | 703 | 136 | 2,820 |
| **2010** | 91,889 | 3,210 | 96,190 | 1,642 | 664 | 116 | 4,463 |
| **2011** | 88,309 | 3,608 | 95,823 | 1,505 | 624 | 140 | 6,227 |
| **2012** | 79,212 | 7,896 | 96,401 | 2,507 | 608 | 111 | 7,699 |
| **2013** | 86,327 | 4,556 | 97,131 | 1,191 | 0 | 51 | 9,573 |

Source: EIA 923

[135] In July 2011, EPA published the Cross States Air Pollution Rule (CSAPR) which was materially different from the Clean Air Transport Rule (CATR) it had proposed in July 2010.

If the five nuclear units are closed at the end of 2016, there will be substantial changes to in-state electricity generation. The results of EVA's modeling, which are summarized in Figures 21 and 22, show lower generation overall post 2016 as well as increased generation primarily from renewables. Both coal and CCGT generation also increase. The decline in generation is attributable to both higher energy efficiency and reduced exports. The first table summarizes Illinois generation with aggressive energy efficiency and renewable energy growth, while the

**Figure 21: Projected Illinois Electricity Generation by Fuel Type (GWh) with Nuclear Retirements Offset by Higher Efficiency and Renewable Energy**

**With Nuclear Retirements, Increased Energy Efficiency and Renewables**

| GENERATION SUMMARY | | | | | |
|---|---|---|---|---|---|
| NUC RETIREMENTS (GWh) | 2015 | 2016 | 2017 | 2018 | 2019 |
| CCGT | 5,005 | 6,651 | 8,942 | 7,343 | 6,771 |
| Coal | 97,970 | 97,398 | 100,769 | 104,893 | 106,250 |
| Gas Turbine | 257 | 195 | 882 | 683 | 713 |
| Hydro | 122 | 123 | 122 | 122 | 122 |
| Nuclear | 94,559 | 96,434 | 52,938 | 52,001 | 52,740 |
| Steam - Gas | 0 | 0 | 0 | 0 | 0 |
| Peaker | 342 | 341 | 360 | 363 | 367 |
| Non-Hydro Renew | 18,645 | 22,483 | 26,055 | 29,694 | 33,316 |
| **TOTAL** | 216,901 | 223,625 | 190,067 | 195,100 | 200,278 |

**Figure 22: Projected Illinois Electricity Generation by Fuel Type (GWh) with Nuclear Retirements Offset by standard Efficiency and Renewable Energy**

**With Nuclear Retirements, Lower Energy Efficiency and Renewables**

| GENERATION SUMMARY | | | | | |
|---|---|---|---|---|---|
| NUC RETIREMENTS (GWh) | 2015 | 2016 | 2017 | 2018 | 2019 |
| CCGT | 8,419 | 11,033 | 10,055 | 9,014 | 8,379 |
| Coal | 96,708 | 96,858 | 101,615 | 105,632 | 107,030 |
| Gas Turbine | 163 | 179 | 1,058 | 1,074 | 1,186 |
| Hydro | 122 | 123 | 122 | 122 | 122 |
| Nuclear | 94,559 | 96,434 | 52,938 | 52,001 | 52,740 |
| Steam - Gas | 0 | 0 | 1 | 0 | 0 |
| Peaker | 335 | 336 | 364 | 368 | 369 |
| Non-Hydro Renew | 12,686 | 13,793 | 15,130 | 15,829 | 16,538 |
| **TOTAL** | 212,992 | 218,756 | 181,283 | 184,039 | 186,365 |

second table shows the same metric but includes the base outlook for energy efficiency and renewable growth. Note that coal generation ramps up slightly beginning in 2017 to account for the lost baseload nuclear generation.

The associated wholesale energy prices for the 2015 to 2019 period are summarized in Figures 23 and 24. The wholesale energy prices reflect the dispatch costs only and do not include either capacity payments or riders. As two RTOs operate in Illinois, PJM and MISO; prices are provided for the relevant sub-regions. The PJM sub-region PJM COMED, which covers Chicago and its surrounding area, is the best indicator of PJM Illinois power prices; the MISO sub-region MISO Central, which cover the balance of the state, is the best indicator of MISO Illinois power prices.

**Figure 23: Projected Illinois Electricity Prices with Nuclear Retirements**

**With Nuclear Retirements, Lower Energy Efficiency and Renewables**

| NUC RETIREMENTS | 2015 | 2016 | 2017 | 2018 | 2019 | 2019 vs 2016 |
|---|---|---|---|---|---|---|
| **PJM COMED** | | | | | | |
| On-Peak | $ 35.73 | $ 35.52 | $ 39.07 | $ 40.99 | $ 42.46 | 20% |
| Off-Peak | $ 30.25 | $ 30.31 | $ 32.20 | $ 33.37 | $ 34.07 | 12% |
| Average | $ 32.99 | $ 32.92 | $ 35.64 | $ 37.18 | $ 38.27 | 16% |
| **MISO CENTRAL** | | | | | | |
| On-Peak | $ 36.90 | $ 36.75 | $ 37.61 | $ 39.32 | $ 40.96 | 11% |
| Off-Peak | $ 31.73 | $ 31.78 | $ 32.66 | $ 33.70 | $ 34.51 | 9% |
| Average | $ 34.32 | $ 34.27 | $ 35.13 | $ 36.51 | $ 37.74 | 10% |

The loss of low cost generation from nuclear units is the major driver of the increase in average wholesale energy prices. Between 2016 and 2019, PJM COMED average wholesale energy prices are forecast to increase by 15% and MISO CENTRAL average wholesale energy prices are forecast to increase by 11%. On-peak prices rise at a greater rate than peak prices as renewables which also have a low dispatch cost play a more significant role in off-peak pricing.

**Figure 24: Projected Illinois Electricity Prices with Nuclear Retirements offset by Higher Energy Efficiency and Renewable Energy**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2019 vs 2016 |
|---|---|---|---|---|---|---|
| **PJM COMED** | | | | | | |
| On-Peak | $ 35.15 | $ 34.86 | $ 37.91 | $ 39.57 | $ 40.80 | 17% |
| Off-Peak | $ 29.74 | $ 29.69 | $ 31.40 | $ 32.37 | $ 33.12 | 12% |
| Average | $ 32.44 | $ 32.28 | $ 34.66 | $ 35.97 | $ 36.96 | 15% |
| **MISO CENTRAL** | | | | | | |
| On-Peak | $ 35.97 | $ 35.72 | $ 36.89 | $ 38.51 | $ 39.98 | 12% |
| Off-Peak | $ 31.05 | $ 30.96 | $ 31.99 | $ 32.96 | $ 33.78 | 9% |
| Average | $ 33.51 | $ 33.34 | $ 34.44 | $ 35.74 | $ 36.88 | 11% |

**Economic Impacts of Higher Electricity Prices.** The electricity dispatch model estimates that wholesale power prices will increase by 5% as a result of the closure of the three nuclear power facilities. A 5% increase in wholesale rates translates to a 1.43% increase in household spending on electricity. The resulting increase in household electricity expenditures will reduce the total funds available for the purchase of other goods and services by 0.017%. Economic impacts resulting from changes in household spending are referred to as induced impacts. The induced impacts of a 0.017% reduction in Illinois household spending are presented in Figure 25. Almost 900 jobs would be lost statewide with a total income of about $45.7 million.

**Figure 25. Induced Economic Impacts of Higher Electricity Rates**

| Higher Electricity Costs and Resulting Employment Losses due to Higher Electricity Prices | |
|---|---|
| **Category** | **Total Effect** |
| Employment | -896 |
| Labor Income | -$45,691,151 |

**Comments on the NEI Study.**

On October 1, 2014 the Nuclear Energy Institute (NEI) released a study entitled "The Impact of Exelon's Nuclear Fleet on the Illinois Economy". According to the organization's website, NEI's objective is to "to ensure the formation of policies that promote the beneficial uses of nuclear energy and technologies in the United States and around the world." NEI reports a membership of over 350 members that operate within or for the nuclear energy industry.

Section 3 of the report "Economic Impacts of Byron, Clinton, and Quad Cities' Retirement" presents a range of projections concerning the economic benefits of the Exelon nuclear fleet and the impact of early retirement for the targeted facilities. The findings in the NEI study are based on the Regional Economic Model, Inc. (REMI) statistical model. Like IMPLAN, REMI is a statistical economic input-output model.

The results of the NEI study differ from the results of the Department's own economic impact study. It appears that the variance between the two studies is a result of different assumptions and data inclusions including the following:

- **Variables concerning the Economic Benefits of the Exelon Nuclear Portfolio.** The use of the following variables tend to increase the economic benefits attributable to the continued operation of Exelon's Illinois-based nuclear assets (and thereby increase the projected negative impact of early retirement):
  - **Value of Electricity Generation.** The NEI model applies an economic impact of $2.4 billion for utility operations for the three targeted plants (Byron, Clinton and Quad Cities). The electricity output from the three plants in 2013 was approximately 43 million MWh according to Exelon. Dividing utility economic value by electricity generation yields an average value of $55.59/MWh generated by the three assets. However, the average value of electricity sold within the Illinois region in 2013 ranged well below $50/MWh (inclusive of capacity and ancillary services). Based on this, it appears that the NEI study may have overstated the value of the targeted nuclear assets by as much as 10%.
  - **Differentiation of In-State and Out-of-State Sourcing.** The NEI report does not differentiate between in-state and out-of-state economic activity. For instance, expenditures for nuclear fuel (processed uranium) make up a significant portion of the economic activities of the nuclear assets. Illinois has no uranium mines and only a portion of uranium processing occurs in the state. Similarly, the NEI report cites total expenditures on goods and services without referencing that over 50% of the amount of

goods and services expenditures by Exelon are not spent in Illinois. By ignoring the out-of-state flow of funds for fuel and goods, the NEI study may be overstating the economic impact of the targeted nuclear assets by as much as 10%.

- **Variables that Overstate Economic Losses Related to Early Retirement.** The NEI study is based on several assumptions that would tend to overstate the economic losses related to early retirement of the nuclear assets. Some of these assumptions include the following:
  - **Aggressive Operating Life Horizon Assumptions.** The NEI study estimated economic losses due to early retirement of nuclear assets through 2030. However, according to the NRC, the operating licenses for three of the five reactors included in the job loss study expire before 2030[136]. While the NRC reports that it has received 1) an application for a license renewal for the Byron Generating Station, and 2) a letter of intent to apply for a license renewal for the Clinton Power Station, there is no indication of license renewal activity for the Quad Cities Nuclear Generating Station[137]. From a modeling perspective, assuming that the assets will continue to operate absent a valid license is an aggressive assumption that would serve to overstate total economic losses within the model.
  - **Ignores the Economic Benefits of Decommissioning.** The NEI study failed to note that early retirement of the targeted nuclear assets would require a significant expenditure of funds to perform required decommissioning. Decommissioning costs are estimated to range between $300 and $400 million per reactor.[138] According to the firm engaged by Exelon to decommission the nuclear reactors at the Zion Nuclear Generating Station, the realized cost of for decommissioning that asset's two reactors will be $1 billion[139], with "approximately $390 million in new economic output, 1,570 man-years of employment, and almost $150 million in employment compensation in Illinois"[140]. From a modeling perspective, assuming that no decommissioning funds would be expended during the study period (2016 through 2030) is an aggressive assumption that leads to an overstatement of total economic losses.

The above-noted differences in data treatment and assumptions appear to account for a significant portion of the difference between the Department's and NEI's economic studies.

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136 Nuclear Regulatory Commission: www.nrc.gov/info-finder/reactor/index.html

137 Nuclear Regulatory Commission: www.nrc.gov/reactors/operating/licensing/renewal/applications.html

138 Nuclear Regulatory Commission: www.nrc.gov/reading-rm/doc-collections/fact-sheets/decommissioning.html

139 http://insideclimatenews.org/news/20110613/decommissioning-nuclear-plant-can-cost-1-billion-and-take-decades

140 www.zionsolutionscompany.com/project/decommissioning/

**Potential Nuclear Power Plant Closings in Illinois**

CHAPTER 5. MARKET-BASED SOLUTIONS

## MARKET-BASED SOLUTIONS

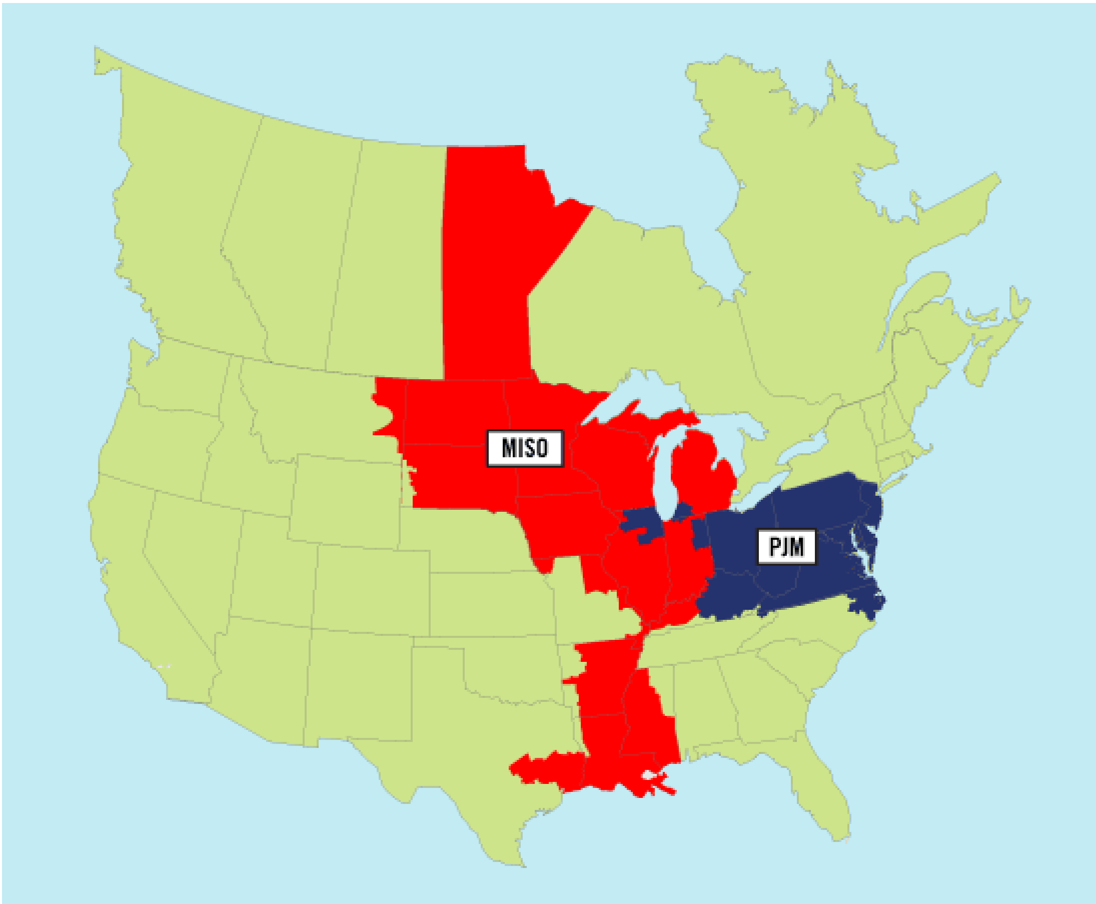
House Resolution 1146 urged all the Agencies to include in their reports "potential market-based solutions that will ensure that the premature closure of these nuclear power plants does not occur and that the dire consequences to the economy, jobs, and the environment are averted." This section discusses potential market-based solutions identified by the Agencies.

Generally, market-based approaches assign a price to pollution and regulated sources of pollution must then determine how to best comply with pollution reduction requirements in a cost-effective manner. In the context of this report, "market-based solutions" are policy instruments that use markets, price, and other economic variables to address a policy priority.

### Assumptions

In developing solutions, the Agencies had to recognize the following core realities:

- **Illinois is not the entire market.** While for many years, Illinois consumers paid regulated rates designed in part to permit Illinois utilities to recover the cost of constructing and operating all nuclear assets located within the state, the plants are no longer supported exclusively by Illinois consumers. The Illinois Electric Service Customer Choice and Rate Relief Law of 1997 restructured Illinois electricity markets and resulted in the transfer of electric generating plants to unregulated companies. Subsequently, ComEd and Ameren utility regions were merged into larger regional wholesale markets (PJM for ComEd and MISO for Ameren). The net effect of these changes is that the use, dispatch, and compensation for all generating plants located in Illinois is dependent on consumer decisions made in over 20 states and Canadian provinces. The figure below shows the PJM and MISO regions in which Illinois utilities participate.




- **Illinois "market-based solution" cannot conflict with FERC rules.** FERC Order 697 allows public utilities, independent power producers, power marketers and other entities to conduct wholesale power sales at market-based rates instead of regulated cost-based rates. To qualify for such authority, market participants must establish that they do not possess the ability to exercise vertical or horizontal market authority. Vertical market power exists in electricity markets when a transmission or distribution owning company can favor itself or its own affiliate in the provision of a competitive service. Horizontal market power exists in electricity markets when a supplier or group of suppliers is able to influence the price of a product for their benefit. In light of these requirements, a narrowly tailored solution that incentivizes electricity outputs from nuclear assets in Illinois could be considered a violation of the market power restriction principles and lead to the suspension of certain market-based ratemaking authority.
- **Market conditions and regulations are changing.** Wholesale market rules concerning compensation for providers of electricity capacity in PJM are likely to change in the near future as a result of proposed rules currently before FERC.[141]

[141] PJM Capacity Performance Proposal, filed with FERC on December 12, 2015 in FERC Docket No. ER15-623.

Additionally, state plans for compliance with the US Environmental Protection Agency's carbon pollution rules under the Clean Air Act Section 111(d) are expected to result in new market rules and incentives. Draft compliance rules are due in June 2016 with the first compliance requirements being applied in 2020. The implication of these new compliance regimes is that carbon-free energy resources, such as nuclear power plants, will stand to achieve additional revenues through compliance incentives.

- **Illinois solution.** In considering the market-based solutions included herein, the General Assembly should be cognizant that these solutions provide varying degrees of certainty for ensuring that funds provided by Illinois consumers would be utilized primarily to support assets within Illinois. In assessing potential market-based solutions, the value of keeping those funds expended and associated economic activity within the state may be considered.

The Agencies have identified five potential market-based solutions that the General Assembly could consider:

1. Rely on existing competitive forces and pending market changes
2. Establish a cap and trade policy
3. Implement a carbon tax
4. Create a low-carbon portfolio standard
5. Create a sustainable power planning standard.

The following sections outline broad principles and issues to consider for each of these categories.

## Solution 1: Rely upon external forces and initiatives

The first option for Illinois is to continue relying upon external forces and initiatives. As grid operations and markets have become more regional, federal oversight of generation markets has increased, and state oversight has become less prominent. This is particularly true in Illinois, where restructuring has resulted in the once traditional vertically-integrated utilities divesting themselves of generating resources. Generating facilities within Illinois do not belong to the traditionally-regulated public utilities. Furthermore, RTOs such as PJM and MISO perform a central coordinating role in the planning and operation of electric transmission and dispatch of generation resources. They anticipate, ameliorate or eliminate reliability problems (such as violations of NERC reliability standards) and identify and organize economically efficient enhancements to the power grid. While they perform a central coordinating function, they rely heavily on market mechanisms and prices to govern supply and demand.

Even though the State still has a strong interest in maintaining an adequate supply of generating resources available to serve Illinois retail load, in 1997 the State changed from a strategy based on ICC regulation of generator-owning utilities to one based on a mixture of private enterprise, markets, prices, and multi-state/multi-national coordination by RTOs. Hence, to identify and solve any potential or actual problems that arise within power markets, including the potential or actual closure of nuclear units, the first option available for Illinois is to continue relying upon competitive forces (supply and demand) and the planning and coordinating structure of the FERC-regulated RTOs. Furthermore, several new initiatives at the federal government and RTO levels could make further state-level initiatives unnecessary.

**USEPA Initiatives**

USEPA's proposed Clean Power Plan under section 111(d) of the Clean Air Act requires reductions in state-wide $CO_2$ emissions beginning in 2020, with a final target date for reductions of 2030. Importantly, the current 111(d) requirements are proposed and not yet final. The final provisions, which are due June 2015, may be significantly different.

The USEPA's proposed rule affords Illinois flexibility in the design of its state plan. Compliance options include a state-based approach where Illinois looks within its borders for the required reductions and a regional approach where Illinois would develop a plan in coordination with other states. Either approach can utilize market-based principles and tools.

It is difficult to determine the impact of compliance with 111(d) on the closure of nuclear power plants given uncertainty over the status of the final rules. It is possible that there may be no market-based solutions to 111(d) that would ensure that nuclear plants avoid premature closure. In developing the appropriate compliance approach in its state plan, Illinois must consider many objectives which include the plan's cost effectiveness (e.g., impact on electricity rates and bills and jobs), ability to meet or exceed the $CO_2$ reduction goals, effect on the reliability of the electricity system, ability to meet required demand-side energy efficiency and renewable energy levels, and ability to ensure the preservation of nuclear energy generation.

**RTO Initiatives**

Ongoing developments within the RTOs have a strong potential to increase market prices. The most significant are PJM's plan to enhance incentives for high availability and/or increase penalties for low availability of generating units, and the potential loss of demand response programs at the RTO level due to legal issues.

As discussed earlier in this report, the nominal impetus to change the capacity market rules was the very cold winter of 2013/2014, which included a January 2014 weather event often referred to as the "polar vortex." The non-performance of certain capacity resources during that harsh weather event amplified concerns about the sufficiency of capacity selected via the current auction process. An August 1, 2014, PJM white paper concluded that a combination of shifting generation from coal to gas, the extreme weather, and increased environmental regulations on coal plants "revealed the current capacity product definition and the current set of performance incentives and penalties for Capacity Resources does not sufficiently address all that is required to ensure that operational reliability will be maintained through all seasons."[142]

Monitoring Analytics, the PJM Independent Market Monitor that serves as an outside expert to monitor and report on PJM market operations, estimates that the Capacity Performance changes will significantly increase capacity prices within the PJM market.[143] Assuming FERC

[142] Problem Statement on PJM Capacity Performance Definition, page 3.

[143] Monitoring Analytics, "Comments of the Independent Market Monitor on PJM's Capacity Performance Proposal and IMM Proposal", September 17, 2014

approves the Capacity Performance proposal (and it survives any potential legal challenges), and those high capacity price estimates prove accurate, then Illinois nuclear plants that successfully bid into the new Capacity Performance auction could benefit from several hundred million dollars of new incremental revenue. However, any new revenue derived from a PJM Capacity performance auction would not become available until 2018.

## State-Level Greenhouse Gas/$CO_2$ Solutions

Currently, damages and associated costs to society caused by pollution are not reflected in the price of generating electricity. As a consequence, energy users do not pay the real cost for energy because these costs are externalized and will be paid by property owners, taxpayers, and the general populace in the form of increased healthcare costs, insurance premiums and damages caused by climate change. Policy approaches that directly or indirectly assign the costs resulting from $CO_2$ pollution to entities responsible for $CO_2$ emissions and then rely on market responses to such assignments can deliver more cost-effective emission reductions than conventional "command and control" regulatory approaches. As nuclear power is a zero $CO_2$ emitting generation source, any approach that internalizes the cost to sources that emit $CO_2$ stands to make nuclear generation relatively more economical and thus perhaps delay or avoid nuclear power plant retirements.

In the environmental protection arena, market-based mechanisms to improve the environment are not new. They have been used to phase out the use of lead in gasoline and limit sulfur dioxide emissions that are responsible for the formation of acid rain. The acid rain program involved an emissions trading (or "cap and trade") program to reduce sulfur dioxide emissions from coal-fired power plants.

Illinois could initiate its own policy aimed at reducing $CO_2$ emissions. Illinois could pursue such a policy unilaterally: either independent of, in preparation for, or as a response to, the Federal Clean Power Plan.

Alternatively, State-specific responses to concerns about global climate change are generally considered less efficient than regional or national/economy-wide efforts. This is because the location of new $CO_2$ emissions is considered irrelevant to the phenomenon of global climate change.[144] In developing its proposal, the USEPA recognized the improved results of broader responses to carbon reduction and proposed a pathway for states to pursue regional implementation plans to comply with the Federal Clean Power Plan. Therefore, Illinois could pursue a regional solution to reduce greenhouse gases (GHG) like$CO_2$ emissions.

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[144] According to the Intergovernmental Panel on Climate Change (IPCC), "For climate modeling, the regional distribution of emissions for well-mixed GHGs ($CO_2$, $CH_4$, $N_2O$, and halocarbons) may not be that important." IPCC, 2000 - Nebojsa Nakicenovic and Rob Swart (Eds.), Chapter 5. http://www.ipcc.ch/ipccreports/sres/emission/index.php?idp=128 According to the Panel on Policy Implications of Greenhouse Warming, Committee on Science, Engineering, and Public Policy, National Academy of Sciences, National Academy of Engineering, Institute of Medicine, "[G]reenhouse gases released anywhere in the world disperse rapidly in the global atmosphere. Neither the location of release nor the activity resulting in a release makes much difference. A molecule of CO2 from a cooking fire in Yellowstone or India is subject to the same laws of chemistry and physics in the atmosphere as a molecule from the exhaust pipe of a high-performance auto in Indiana or Europe." *Policy Implications of Greenhouse Warming*, National Academy Press, Washington, D.C. 1992, p. 5.

Illinois could also pursue a hybrid approach. Illinois officials have participated in discussions with other states in the Midwest regarding plans to comply with its 111(d). It is clear from these discussions that developing a regional approach will take time. Given the time it may take to execute a regional plan, Illinois may find it necessary and/or beneficial to pursue a state-specific carbon policy as a bridge to a regional approach.

If the State decides to institute policies, either unilaterally or cooperatively with other states to vigorously reduce GHG/$CO_2$ emissions, one impact would likely be an increase in the profitability of carbon free sources of power generation, including Illinois nuclear units, and consequently delay their retirement.

The following sections identify State-level GHG/$CO_2$ solutions.

## Solution 2: Cap and Trade Program for Carbon Dioxide Emissions

Illinois could enact a cap and trade program for $CO_2$ emissions. A cap and trade approach could take several forms including an intra-state program, where only Illinois sources were involved, or a multi-state cap and trade program. A multi-state approach would entail any number of states that interact to meet an overall regional cap on $CO_2$ emissions, or which simply establish a trading platform that recognizes a common currency (i.e., the value of a ton of emissions).

While there are other emission-control policy instruments, the cap and trade system is often cited as one of the more economically efficient approaches because it lowers the overall cost of emissions reductions across the participating states. A cap and trade program has two fundamental features.

1. A federal or state legal authority sets a limit (or "cap") on the amount of pollutant or other unwanted substance, like $CO_2$, that may be emitted within a given geographic area over a given period of time. For purposes of Illinois unilaterally imposing a $CO_2$ cap and trade program on power plants, the geographic area would be the State. Illinois may also join other states that have created regional $CO_2$ cap and trade programs or develop a new regional program with other states in the Midwest. The period of time might be a calendar year, with different caps applying each year.
2. Once an emissions limit is established, the cap and trade program administrator would issue a commensurate number of emission permits (or "allowances"), either through an auction, or by simply giving them away (e.g., to historical emitters of $CO_2$). In order for a power plant to emit X tons of $CO_2$, its owner would have to possess X tons worth of allowances, and the power plant could not increase its emissions without obtaining more allowances or being subject to penalties. Even though the total number of allowances for all power plants would be fixed, cap and trade programs allow power plant owners to buy and sell allowances among themselves at unregulated market prices.

The efficiency of cap and trade stems from taking advantage of differences between power plants and between power plant owners. Emissions reductions do not cost the same everywhere, and some businesses may be better at reducing emissions than others. [145] With the option of buying and selling tradable emissions permits on the secondary market, power plant owners have an incentive to determine the most profitable or least costly option: (A) to adopt new technology or take other actions to reduce or eliminate $CO_2$ emissions, and then sell any excess of emissions permits at the market price; or (B) to maintain existing practices and buy any shortfall of emissions permits at the market price. Over time, permit prices will reflect the price where power plant owners become indifferent between adopting technology to limit emissions and paying the permit price to emit additional units of $CO_2$. In other words, the price of permits would be determined by the marginal cost of reducing emissions up to the level determined by federal or state authorities.

**Illinois Experience**

Illinois has significant experience in analyzing and designing carbon reduction programs. In 2006-07, the Illinois Climate Change Advisory Group (ICCAG) utilized an extensive stakeholder process to make recommendations on how to reduce greenhouse gas emissions in the state. Among the recommendations was a cap and trade program. The ICCAG modeled two options: a stand-alone State of Illinois program, and joining the Regional Greenhouse Gas Initiative (RGGI).[146]

Illinois was also a member of the Midwest Accord, a group of six states (Illinois, Minnesota, Wisconsin, Iowa, Michigan, Kansas) and the Canadian province of Manitoba, that developed a Midwestern cap and trade program during 2008-2010. This group participated in an effort to see if RGGI, the Midwest Accord and the Western Climate Initiative (WCI, a RGGI-like group being formed in the western states) could be made compatible with each other. This effort was titled North America 2050, and continued meeting until roughly late 2013. While the Accord, WCI and NA 2050 did not result in larger cap and trade programs, the work will help inform an Illinois or regional cap and trade program in the future.

Currently, the ICC (Illinois Commerce Commission) and IEPA (Illinois Environmental Protection Agency) participate in a group known as the Midcontinent States Environmental and Economic Regulators (MSEER). This group is designed to explore potential multi-state compliance options under the USEPA's Clean Power Plan. A number of trading programs have been discussed, and MSEER's goal is to help states decide whether to seek greenhouse gas reductions on their own or in combination with other states. PJM and MISO have done some initial modeling work to analyze whether state-by–state Clean Power Plan compliance would be more or less expensive than multi-state options.

The Agencies' prior experience with these GHG reduction efforts will help inform the discussion of methods to determine the price and value of nuclear generation. Any approach

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[145] The clear efficiency benefit of the cap and trade system depends on the assumption that the geographical location of the power plants is not relevant to the harm of their emissions or that such geographic-based differences in the harm are taken into account within the cap and trade system.

[146] The Regional Greenhouse Gas Initiative (RGGI) is the first market-based regulatory program in the United States to reduce greenhouse gas emissions. RGGI is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap and reduce CO2 emissions from the power sector.

taken with respect to the nuclear plants should be mindful of the looming Clean Power Plan compliance requirements.

**Regional Options**

A regional approach will take more time to establish given the necessity of negotiating with other states. To be responsive to the immediate nuclear issue, Illinois may need to act unilaterally in the short term. Any Illinois-only approach adopted could serve as the model for a regional approach as other states could join at a later date. Thus it is worth considering some of the options associated with a regional approach at this time.

One option under a regional approach would be for each state to have its own emissions reduction goal. Notably, while this option is not specifically authorized by the newly proposed Federal Clean Power Plan (CPP), it is not explicitly rejected. Illinois has been a party to comments asking USEPA to allow for the non-blending of state specific emissions rate reduction goals in trading programs in its final Clean Power Plan rule.

In a more complex multi-state program, Illinois could agree with other participating states on its share of the annual $CO_2$ emissions cap, typically on a ton per year emissions basis. Dependent on its share of emissions, Illinois could allocate a portion of its emission allowances to affected fossil fuel-fired sources and a portion of the allowances could be auctioned. The auction proceeds could be placed into a fund and used to mitigate customer rate increases from compliance with the cap and trade policy and to promote environmentally beneficial actions such as energy efficiency, renewable energy, or other zero emitting $CO_2$ sources such as nuclear. To the extent that costs to fossil fuel-fired generating sources are increased under this approach, nuclear powered electric generating units stand to benefit in regard to cost effectiveness thus lessening the likelihood of nuclear unit retirements.

Illinois also has the option of joining an existing cap and trade program such as the RGGI. This would be a reasonably straightforward and immediate alternative at the potential expense of Illinois or Midwestern interests. Extensive modeling would be needed to determine if RGGI, a Midwestern alternative or a state-only trading program is better for Illinois.

The costs and benefits of any of the above approaches (Illinois-specific, new regional multi-state program or joining an existing program) should be modeled in order to compare the different alternatives.

**Further Considerations**

Sometimes cap and trade systems allow the use of “offsets” in place of allowances. For instance, the RGGI defines offsets as project-based greenhouse gas emission reduction outside of the capped electric power generation sector. At this time, the RGGI States limit the award of offset allowances to five project categories, each of which is designed to reduce or sequester emissions of carbon dioxide ($CO_2$), methane ($CH_4$), or sulfur hexafluoride ($SF_6$) within its nine-state region. None of the five categories permitted by RGGI involve nuclear power generation. Since nuclear generation does not emit carbon dioxide, it is conceivable that a State would allow nuclear facilities to generate offsets that could be sold to fossil fuel plant owners. However, the proposed Clean Power Plan does not allow for offsets, which may facilitate an eventual change in RGGI in order to meet the federal requirements.

Such carbon trading regimes, in addition to addressing Illinois concerns, could be a compliance option to the proposed EPA Clean Power Plan under section 111(d) of the Clean Air

Act. Compliance with a carbon trading system would reoccur annually and would be paid for by all consumers within the state or within the region (not exclusively Illinois consumers) depending upon the selected approach. Additionally, a proportionate share of the proceeds from the carbon credits auctions under a carbon trading system could be retained by the State. As an example, approximately $100 million[147] in carbon credit proceeds were gathered in the most recent RGGI auction process. The State can then use its proportionate share of those proceeds to lower customer bills, support energy efficiency, renewable energy and other greenhouse gas reduction programs as well as retraining programs and low income bill payment assistance programs.[148]

## Solution 3: Carbon Tax

Several governments outside the United States have some form of carbon tax. The rules on what is taxed, the tax rates, and other policies vary from place to place. In general, electricity generators that emit $CO_2$ are taxed for each ton of $CO_2$ emitted. Such taxes create an incentive for fossil-fueled generators to reduce emissions to the level at which it is less costly to pay the carbon tax than it is to reduce $CO_2$ emissions any further. A high enough tax rate could lead some plants to close. Due to the cost of emissions-reducing technologies and the taxes associated with carbon-based generation, wholesale electricity prices would inevitably increase in response to a carbon tax.

A carbon tax or fee establishes a cost to emit carbon or use carbon containing fuels. There are many versions of, and theories on, the design and implementation of a carbon tax. One version of a carbon tax consists of a fee being imposed on the emissions of $CO_2$ from power plants. The tax could be scheduled to start low and increase over time. The tax would likely send signals to the market for electric power that favors nuclear generation and renewable energy as $CO_2$ free generation sources. Revenue from this tax could be used to subsidize a particular type of generation to increase the likelihood of $CO_2$-free generation. Another version of a carbon tax would place a fee on all carbon from fossil fuel sources extracted within and imported into the state. All providers of these fossil fuels would pay a tax equivalent to the amount of carbon in their product upon extraction and importation. Under both types of carbon tax, sources that do not rely upon fuels containing carbon stand to benefit as fossil fuel prices include a levy.

British Columbia has a carbon tax of about US$25/ton of $CO_2$. The tax is purported to be revenue neutral; as revenue is acquired through the carbon tax, personal and corporate income tax rates decline to offset the carbon tax revenue. For approximately two years, Australia had a carbon tax of about US$19.60 per U.S. ton of $CO_2$; it was repealed earlier in 2014. Sweden has a carbon tax of about $150/ton, but the tax is not levied on electricity generation. The impact of such taxes on emissions is difficult to determine because a multitude of factors could affect $CO_2$ emissions, such as a global recession. However, most jurisdictions are reporting at least a 15% reduction in emissions as a result of the taxes.[149]

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[147] http://www.rggi.org/market/co2_auctions/results/auction-26

[148] http://www.rggi.org/rggi_benefits/program_investments

[149] See http://www.carbontax.org/services/where-carbon-is-taxed for a more detailed description of carbon taxes.

Finally, an additional consideration is that while a carbon tax would incent generators to opt for lower carbon options, it does not necessarily mean that emissions will fall to a desired level. In such an instance, the carbon adder would have to be adjusted. This process may have to be continually revisited in order to be used as an effective carbon reduction tool.

## Solution 4: Low Carbon Portfolio Standard

Like renewable portfolio standards, a Low Carbon Portfolio Standard ("LCPS") would require wholesale purchasers of electricity to obtain specified percentages of their supply from a broader class of zero carbon sources or sources with lower carbon intensity ($CO_2$ emissions per kilowatt-hour) than that of fossil-fuel generation. Such an approach could allow retail energy providers to demonstrate compliance via tradable credits.

These types of policies have at times been called "clean energy standards" ("CESs"). The term "clean" is ambiguous, and what forms of energy generation are to be considered "clean" is often debated by a variety of interest groups. For purposes of this report, and in light of the imminent federal carbon reduction requirements, the most appropriate focus is on low or zero carbon emitting generation sources.

### Examples – Federal bills

Several legislative proposals for Low Carbon Portfolio Standards (LCPSs) have made their way to Congress but have not been enacted into law. These bills have included electricity portfolio standards that set requirements for low carbon energy, including renewable energy and certain non-renewable electricity generation technologies, such as new nuclear power and coal with carbon capture and storage. For instance, in the 111$^{th}$ Congress (2009-2010), Senate Bill 20 would have required retail sellers of electricity to obtain "a percentage of the base quantity of electricity … from clean energy or energy efficiency."[150] The minimum percentages started at 13% in 2013 and 2014, rose to 15% between 2015 and 2019, and rose by an additional 5% every five years thereafter until reaching 50% by 2050. The requirements were to be met either by submitting "clean energy credits" or "energy efficiency credits" (which would be obtained through a "Federal Clean Energy and Energy Efficiency Credit Tracking Program"), by making "alternative compliance payments" at the initial rate of 3.5 cents per kilowatt hour adjusted for inflation, or by a combination of those activities. The bill permitted a retail electricity seller holding excess clean energy credits to sell or transfer the credits to other retail sellers. Furthermore, the bill permitted unused clean energy credits to be carried forward for use in subsequent years. The bill allowed retail sellers to petition the Secretary of the Energy Department to waive, for the following compliance year, all or part of the requirements in order to limit the rate impact of the incremental cost of compliance to not more than 4 percent per retail customer in any year. While Senate Bill 20, discussed above, was a federal bill and was never enacted into law, a similar approach has been adopted by at least two states.

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[150] S.20 -- Clean Energy Standard Act of 2010 (Introduced in Senate - IS): http://thomas.gov/cgi-bin/query/z?c111:S.20:

**Examples –State laws**

In Ohio, Senate Bill 221 of the 127th General Assembly established an alternative energy portfolio standard ("AEPS") for the State.[151] The law mandates that by 2025, at least 25 percent of all electricity sold in the state come from alternative energy resources. At least half of the standard, or 12.5 percent of electricity sold, must be generated by renewable sources such as wind, solar (which must account for at least 0.5 percent of electricity use by 2025), hydropower, geothermal, or biomass. The additional 12.5 percent of the overall 25 percent standard can be met through certain alternative energy resources, like ***third-generation nuclear power plants***, fuel cells, energy-efficiency programs, and clean coal technology that can control or prevent carbon dioxide emissions. Note that none of Illinois nuclear plants are "third-generation" designs.[152]

In Indiana, Senate Act No. 251 of the 117th General Assembly (2011) [153] established a ***voluntary*** LCPS, which defines very broadly a "clean energy resource" as clean sources, alternative technologies, or programs used in connection with the production or conservation of electricity (energy efficiency and demand response).

Utilities that choose to participate in Indiana's LCPS are eligible to receive various incentives from utility ratepayers, including:

> (1) The timely recovery of costs and expenses incurred during construction and operation of eligible projects;
>
> (2) The authorization of up to three (3) percentage points on the return on shareholder equity that would otherwise be allowed to be earned on projects;
>
> (3) Financial incentives for the purchase of fuels or energy produced by a coal gasification facility or by a nuclear energy production or generating facility, including cost recovery and the incentive available under subdivision (2);
>
> (4) Financial incentives for projects to develop alternative energy sources, including renewable energy projects or coal gasification facilities; and
>
> (5) Other financial incentives the Indiana public utilities commission considers appropriate.

In addition, legislatures in both Utah and Virginia have enacted renewable portfolio standards that, among other things, base renewable energy resource goals on a percentage of electricity sold minus energy supplied by nuclear power plants.[154] The Utah law also subtracts

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[151] Ohio's Renewable Energy Portfolio Standard: http://www.legislature.state.oh.us/bills.cfm?ID=127_SB_221. Ohio Public Utilities Commission page dedicated to the standard: http://www.puco.ohio.gov/puco/index.cfm/industry-information/industry-topics/ohioe28099s-renewable-and-advanced-energy-portfolio-standard/#sthash.ArNJOIoK.dpbs.

[152] According to the World Nuclear Association, the first so-called third generation advanced reactors have been operating in Japan since 1996. http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Power-Reactors/Advanced-Nuclear-Power-Reactors/ Exelon's Illinois plants were all built prior to 1990.

[153] http://www.in.gov/legislative/bills/2011/SE/SE0251.1.html

[154] For more information, see the US Department of Energy's Database of State Incentives for Renewables and Efficiency. In particular, for Utah, see

energy supplied by demand-side management measures and fossil fuel power plants that sequester their carbon emissions.

**Adaptation of a Low Carbon Portfolio Standard for Illinois**

The General Assembly could adopt a Low Carbon Portfolio Standard, along the lines of the standards discussed above, that could be fairly quickly implemented. This could be as a stand-alone solution, or as interim approach until a more comprehensive long-term solution to valuing carbon reductions is developed and implemented. However, the specific circumstances of the restructured Illinois electric market would have to be considered. Retail competition in Illinois has generally helped to lower prices and provide market-based efficiencies, resulting in Illinois electric rates that are generally lower than in neighboring states. The benefits restructuring has brought to Illinois must be considered when examining LCPS options. A portfolio standard creates obligations on a supplier of electricity to end use customers and the implementation of those obligations has the potential to impact competitive pricing options. This is distinct from the options discussed in the prior section that more directly impact generators of electricity.

An Illinois LCPS could be broadly designed in several different ways:

1. Update the existing RPS to become a broader LCPS that would allow participation by low carbon resources in addition to the conventional set of currently eligible renewable resources. This could be accomplished either by consolidating the different compliance paths for ARES and utilities into one portfolio, or by independently (and consistently) updating those separate standards.
2. Create an additional stand-alone portfolio standard focusing on low or no carbon emission energy sources, such as nuclear energy, that are not already included in the existing standards.

In considering these approaches to the LCPS, the current RPS structure must be considered because of it either being updated or supplemented. The current RPS has two components: 1) procurement by the IPA for eligible retail customers of the utilities; and 2) a separate compliance path for the customers of ARES.[155] ARES compliance obligations are met through a combination of Alternative Compliance Payments ("ACPs") by the ARES that are deposited into the IPA-administered Renewable Energy Resources Fund ("RERF"), and through ARES self-procurement of Renewable Energy Credits ("RECs") equivalent to a specified portion of their sales. These two components are fundamentally different in implementation.

For eligible retail customers, renewable resource procurements conducted by the IPA are forward looking: the IPA secures resources for a future period of time, and funds are collected by the utilities over time from customers to pay for such resources via a rider recovery mechanism. In contrast, ARES have an annual reporting obligation to the ICC to make their ACP payments

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http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=UT13R&re=0&ee=0 and, for Virginia, see http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=VA10R

[155] The current RPS only applies to the roughly 90% of the load in Illinois served by ComEd, Ameren Illinois and alternative retail electric suppliers. It does not apply to municipal electric utilities and rural electric cooperatives.

and show their REC purchases and retirements for the previous delivery year.[156] For ARES, this is a backward-looking process for which they presumably embed the costs of compliance into their prices offered to customers. The ARES lack an easy mechanism to recover additional unexpected costs.[157] In addition, while Public Act 98-0672 has allowed the IPA to begin to move forward with spending a portion of the funds deposited into the RERF, structural problems still exist within Section 1-56 of the IPA Act that would need to be addressed in order to ensure any new funds collected are in fact used for the intended purpose of procuring carbon free resources.

The implications of this difference for an LCPS is that the phase-in period for the eligible retail customers and the ARES customers would have to be different if the current RPS model is closely followed. While the IPA could quickly implement a competitive procurement for eligible retail customers, consideration must be given to ARES' existing supply contracts and a lag of at least a year would exist before ARES make any payments or acquire carbon free emissions credits. As ARES currently serve over 80% of the total load of the state, this would be a significant issue. In the alternative, the IPA procurement could be structured to cover all load and recovered by the utilities from all customers through a competitively neutral rider.

For the option of creating a standalone LCPS separate from the current RPS, care would be needed to ensure that if resources could qualify for either procurement, that gaming of the obligations, prices and procurement process would not take place. Careful product definitions and terms would have to be established. Likewise if the LCPS is to replace the RPS, then it is important that the benefits and value of the existing RPS structure are not lost and that renewable resources would be given a clear opportunity to participate fully, and that funds previously collected to support renewable resources would indeed be used to procure only resources meeting that definition.

**Solution 5: Sustainable Power Planning Standard**

Regardless of any market based solution it adopts, the General Assembly could adopt a Sustainable Power Planning Standard ("SPPS") – a unified set of standards and goals applicable to the procurement of power, including energy efficiency and demand response. Recognizing the United States Supreme Court decisions confirming that carbon dioxide is a pollutant to be regulated by USEPA under the Clean Air Act and in anticipation that the EPA's Clean Power Plan, the SPPS could establish goals for reducing carbon dioxide pollution at existing Illinois electric generating facilities.

Recognizing concerns about the sufficiency of capacity selected via the current Regional Transmission Operator processes (as exemplified by deficiencies identified with respect to the January 2014 weather event often referred to as the "polar vortex"), the SPPS could prioritize operational reliability in power production (including reliability in the provisions of energy efficiency and demand response). This SPPS approach could account for these goals and objectives as well as those within Illinois' existing portfolio standards (e.g., energy efficiency

[156] Energy delivery years end May 31st and ARES must report to the ICC by September 1st.

[157] Some ARES do include a regulatory change clause in their contracts, but invoking such clauses can generate customer dissatisfaction.

portfolio standard, renewable portfolio standard, and clean-coal portfolio standard), effectively unifying energy planning and incentives in the state by orienting those activities into a common planning regime and implementation platform. Through an SPPS the General Assembly could coordinate Illinois energy policy to ensure that any costs borne by Illinois consumers as a result of Illinois energy statutes are returned as benefits to Illinois in the form of reliable, clean, and affordable electricity.

A SPPS could serve as the basis for providing direct financial incentives through the monthly utility billing process via a distribution rate charge such as with the Energy Efficiency Portfolio Standard to promote the development and retention of clean electricity resources within the state. The SPPS could further replace all the existing portfolio standards with a new standard and mechanism that would direct incentives to energy resource projects that reduce, avoid, or offset greenhouse gas emissions. Incentives directed through the SPPS process would be allocated according to a strategic plan that prioritizes energy resource projects according to their ability to replace retiring electricity capacity, produce little or no greenhouse gas emissions, and minimize electricity prices and volatility. These resources could be either demand side (e.g., energy efficiency or demand response) or supply side (e.g., renewables, nuclear or clean coal). This SPPS approach would effectively unify energy planning and incentives in the state by orienting those activities into a common planning regime and implementation platform.

This strategic planning approach for the state would identify the near/medium/long term electricity requirements for the entire state, evaluate the sufficiency of existing assets in meeting those requirements, and evaluate the efficacy and value of various options to fill any identified shortfalls in the near/medium/long term. Specific to the medium and longer term planning horizons, the SPPS approach would focus on supporting the development of new resources to replace retiring resources as they reach the end of their useful life.

As a comprehensive planning approach, this option could require significant implementation time and consideration would have to be given to how to phase out the existing portfolios in order to adopt this approach. In particular the variation between current portfolios that are equally applied to all customers (e.g., energy efficiency) and those that are applied differently to ARES and utility customers (e.g., the RPS) would have to be reconciled. Additionally as this approach would create incentives for generation (or generation avoiding) resources, a cost recovery mechanism would need to be developed so it could be applied equitably to all customers in Illinois.

# AFTERWORD

This report has endeavored to answer the questions put to the agencies in HR 1146, and while it acknowledges a number of issues that will have an impact on the included market based solutions, another key issue is timeliness of implementation. With respect to this issue, the Clean Power Plan will become increasingly important.

The proposed rule provides that states must submit compliance plans by June 2016 (or June, 2017 if states are working on a multi-state solution). These plans will necessarily encompass all of the discussions found above. For the purpose of this report, the agencies have addressed the issues raised by HR 1146 independent of the upcoming 111(d) state implementation plan analysis. As Illinois determines the proper response to nuclear plant issues, any response must be viewed in the context of the Clean Power Plan and the potential response to its requirements.

In that context, in analyzing the time necessary to implement any of the included market based solutions to the nuclear plant issue, any could be, and probably will need to be done on a similar timeline. This would include the cap and trade alternatives, which although seemingly more complicated than the other options, could be set up as quickly as the other solutions.

There is an old adage: "a rising tide lifts all boats." Solutions adopted to prevent the premature closure of Illinois nuclear plants should be designed with the goal of raising the tide of the Illinois energy sector. When evaluating the solutions included in this report and any alternatives offered by stakeholders, holistic solutions aimed at solving fundamental market challenges are preferable. The right energy policy has the potential to minimize rate increases to families and businesses while positioning Illinois as a national leader in the development of clean energy. As neighboring states address Clean Power Plan compliance, new clean energy investments by Illinois may offer first-mover advantages in increasingly carbon-constrained energy markets. If Illinois is to move forward with a robust response, the full impact and potential of any such policy must be fully explored.

The Agencies contributing to this report look forward to working with the Illinois General Assembly on the challenge of shaping Illinois' energy policy to address the economic and environmental challenges facing our state as we help to craft a program that minimizes the rate impact and environmental harm to the citizens of Illinois, maximizes Illinois' economic development, creates good paying jobs, and increases our stature as an energy leader in the Midwest and the Nation.

# APPENDICES

# Illinois Commerce Commission Appendix

To investigate the impact of closing specific Illinois nuclear units, the ICC received assistance from PJM, MISO, the Illinois Institute of Technology's Robert W. Galvin Center for Electricity Innovation, and the Monitoring Analytics (the PJM market monitor), each of which has the data, modeling capabilities, and expertise to carry out such an analysis. The reports provided to the Commission by each of these entities follow.

# PJM Response to Illinois Commerce Commission Request to Analyze the Impact of Various Illinois Nuclear Power Plant Retirements

October 21, 2014

**Table of Contents**

# I. Summary

This report responds to a request from the Illinois Commerce Commission requesting that PJM analyze the impacts of hypothetical Illinois nuclear power plant retirements. The request was to assess the reliability, energy market and certain environmental impacts for different nuclear plant retirement scenarios. The analyses were based on assumptions about future fuel prices, peak loads and generation mixes for the year 2019. Changes in any of those assumptions could result in different expected impacts. Therefore, PJM also executed energy market sensitivity scenarios based on these assumptions as described in the report.

# II. PJM's role in the Illinois transmission system

PJM is a regional transmission organization with more than 900 members that is operated on a not-for-profit basis. PJM's primary responsibility is to manage and plan the electric transmission system in all or parts of 13 states and the District of Columbia in a safe and reliable manner. In Illinois, PJM manages the transmission system owned by Commonwealth Edison. In real-time operations, PJM must balance electric customer usage (demand) with the available resources (supply), including nuclear generation stations, to provide enough electricity to meet consumer demands. In short, PJM and its members work closely together to "keep the lights on."

PJM's operations are similar to those of air traffic controllers, who are responsible for the safe and reliable operation of airline traffic. Air traffic controllers manage the flow of aircraft through the skies and landings at the nation's airports. Air traffic controllers are regulated by the federal government, do not own the airplanes, the landing rights or the airports but have broad responsibilities for managing air traffic. Likewise, PJM is regulated by the Federal Energy Regulatory Commission, manages the flow of electricity over the electric transmission system for its members but does not own the electricity or the transmission grid.

PJM also operates a trading platform, which may be compared to the Chicago Board of Trade. Through this trading platform, PJM members can buy and sell wholesale energy and related services in day-ahead and real-time markets. PJM also is responsible for securing adequate generating resources to meet future consumer demands and for the long-term planning of the high-voltage transmission system.

These responsibilities place PJM in a unique position to assess the impacts of power plant retirements.

# III. Nuclear stations' value to electric transmission grid

PJM values the contribution nuclear power stations, which seldom need refueling and operate with high efficiency, make for a balanced generating portfolio and significantly add to the overall reliability of the power grid. For instance, during the extremely cold weather in Illinois and other states this past January, known as the Polar Vortex, the Byron, Quad Cities and Clinton nuclear power stations operated at or close to full output and provided needed reliability support to PJM as well as to neighboring transmission systems. PJM's records indicate that for the two stations located in the PJM footprint, the Quad Cities nuclear power station operated in January at 100 percent of its rated capacity and the Byron nuclear power station at approximately 97 percent. All three of these nuclear power stations were critically important in maintaining a safe and reliable transmission system during the record electricity demand served in January. PJM also recognizes that the State of Illinois would rely on low-carbon sources of energy, such as nuclear, to meet carbon dioxide limits proposed by the U.S. Environmental Protection Agency.

# IV. The Illinois Commerce Commission request to assume the "unavailability," or retirement of three Illinois nuclear power stations (Byron, Quad Cities and Clinton) in 2019.

## *Core Request*

The ICC asked PJM to model four scenarios concerning the unavailability of nuclear power stations.

Specifically, in September, the commission asked PJM to analyze the following four scenarios using calendar year 2019 as the base year and assuming:

1. All Illinois nuclear power stations are available,

2. All Illinois nuclear power stations, except the Byron station, are available,

3. All Illinois nuclear power stations, except the Byron and Quad Cities stations, are available, and

4. All Illinois nuclear power stations are available except the Byron, Quad Cities and Clinton nuclear power stations.

The commission also noted that a PJM committee, the Transmission Expansion Advisory Committee, had agreed upon and published certain input parameters and forecast assumptions such as customer load growth and transmission upgrades for 2019. The commission asked PJM to use those input parameters and forecast assumptions. In its analysis, PJM recognizes that these assumptions, which are based on the best available data, may change and that any changes could have significant impacts on the ultimate accuracy of the analysis.

## *Additional Requests*

The commission also asked, to the extent feasible, for PJM's analysis of the unavailability of only the Clinton nuclear power station and separately, the unavailability of only the Quad Cities nuclear power station.

Note that due to time limitations, the reliability analysis does not consider the unavailability of only the Quad Cities nuclear power station and contains limited analysis of the unavailability of only the Clinton station.

For each of these scenarios the commission asked PJM to model any new electric transmission system investments that may be necessary to continue to have a reliable electric transmission system in Illinois due the possible retirement of the nuclear power generators. The commission also asked PJM to project the likely impact of the nuclear power station unavailability on the wholesale prices of energy in Illinois – which are termed wholesale "locational marginal prices."

Finally, the commission asked for estimates of other expenditures necessary to serve customer load and the impacts of nuclear plant unavailability on future carbon dioxide and other power plant emissions, both in Illinois and the PJM region. While the requested analysis was particularly concerned with PJM modeling such scenarios in ComEd's service territory, which is in Northern Illinois, the ICC also requested PJM to analyze what could occur in the Ameren-Illinois service territory, which is in the Mid-Continent Independent System Operator's footprint where the Clinton nuclear power station is situated.

# V. Analysis Assumptions

## *Reliability Analysis Assumptions*

The scenarios required PJM to undertake analysis concerning the unavailability – what also could be termed "retirements" – of five nuclear reactor units – two each at Byron and Quad cities and one at Clinton. In the ordinary course of business the PJM planning analysis to evaluate the reliability impact of the unavailability of one generation unit on the PJM-managed transmission system requires at least 30 days to complete. The ICC request asked that the reliability analysis for all five generation units and the energy market impacts of the unavailability of those generators be completed in less than a total of 30 days. As a result of this aggressive timeline, PJM had to make certain assumptions to complete the analyses in the given timeframe.

As noted, the analyses that PJM was asked to complete included both an assessment of the transmission system reliability impact of each of the scenarios, an assessment of the energy market impact of each of the scenarios and the potential emissions levels as well.

The reliability analyses that were completed included the PJM load deliverability testing, generation deliverability testing, common mode outage testing and North American Energy Reliability Corp. category C3 (N-1-1) testing. This NERC testing relates to how reliable the transmission system would be if certain transmission facilities become unavailable at the same time.

Given the time constraints, an exhaustive analysis of all applicable reliability criteria, including the Commonwealth Edison local transmission owner criteria, was not performed. However, historically the analyses that were completed by PJM have driven the majority of the upgrades that are required due to generation retirements. The reliability impacts were evaluated on a 2019 summer peak base case that was modified for each of the retirement scenarios requested by the Illinois commission. Modelling assumptions including transmission topology, loads, generation and interchange were consistent with the assumptions being used for the 2014 PJM Regional Transmission Expansion Plan, or RTEP, which set forth the 2019 base case criteria. It should be noted that severe winter conditions, like the Polar Vortex conditions experienced this past winter, were not studied.

## Energy Market Assumptions

The Base Energy Market assumptions used for this analysis were derived from the 2014 Annual PJM RTEP Market Efficiency model for the 2019 study year. Therefore, all base input assumptions were equivalent to the assumptions as posted on the PJM Market Efficiency web page located at the following link:

http://pjm.com/~/media/planning/rtep-dev/market-efficiency/market-efficiency-input-assumptions.ashx

Key energy market input assumptions are provided in Table 1 below.

**Table 1:** Key Energy Market Input Assumptions

| | Study Year 2019 |
|---|---|
| Coal Prices ($/MMBtu) | 3.24 |
| Gas Prices ($/MMBtu) | 4.79 |
| Peak Load (MW) | 165,982 |
| PJM Generation Reserve Requirement (MW) | 177,538 |
| PJM Modeled Generation (Includes FSAs) (MW) | 198,145 |
| PJM Excess Modeled Generation above Reserve Requirement (MW) | 20,607 |

The key input assumptions for this study include fuel prices, PJM peak load, and modeled generation. Coal and natural gas fuel prices for the 2019 study year were obtained from commercially available databases. PJM's January 2014 Load Forecast Report provided the transmission zone load and energy data. The PJM base generation model includes all existing in-service generation plus actively queued generation with an executed Facilities Service Agreement (FSA), less planned generator deactivations that have given formal notification to PJM of their intent to retire. FSA generation included in the base analysis represents a projection of generation that may or may not proceed forward through the PJM queue process. Inclusion of FSA units is consistent with the RTEP procedures.

The inclusion of FSA units in the generation model in 2019 results in total PJM capacity exceeding the PJM reserve requirement by more than 20,000 megawatts. This is depicted in Table 1. This amount of additional reserve generation, which is considerably greater than historical reserve levels, is significant because this generation will be used in the simulation to replace higher-cost existing generation. Although advanced in the interconnection process, FSA generation has not committed to interconnecting to the transmission system, may not yet be constructed and as such is somewhat speculative. It is added to market efficiency models to ensure reserve requirements are met throughout PJM's 15-year planning horizon and to match the RTEP transmission model, which includes necessary transmission upgrades required to satisfy reliability criteria with the FSA units interconnected. Given the optimistic assumption about FSA generation, and the resulting higher generation reserves, the base energy market impacts noted in this scenario may be less severe (i.e., load payments may increase in the study by a lesser amount) than what may be seen if the plants were to actually retire.

Fuel prices also have a major impact on the results because they directly impact the generation offer bids and consequently the load payments and locational marginal prices. The base analysis utilized the fuel prices from the

PJM 2014 Annual Market Efficiency Cycle. These fuel prices were relatively low for the 2019 study year. In particular, the difference between coal prices and natural gas prices is small, as shown in Table 1, which usually results in more lower-priced gas units displacing coal units in the simulation.

The identified key input assumptions are important because these assumptions have the most impact on the energy market simulation results. These base assumptions were used because they were vetted with stakeholders through the regional PJM RTEP process and are also being used for the 2014/2015 Annual PJM Market Efficiency cycle. However, sensitivities on these key input assumptions may have major impact on the results. Therefore, PJM performed additional sensitivity analysis on two of the key input assumptions to provide a range to help bound the results.

The first sensitivity analysis was to modify the base input generation assumptions to not include the additional FSA units in the analysis. Removal of the additional FSA units in the analysis would be consistent with historical Market Efficiency rules for which FSA units were not included. The reserve requirement will still be achieved because the removal of the FSA units does not result in total modeled generation being under the Reserve Requirement.

The second sensitivity analysis was to modify the sensitivity scenario that modeled sufficient FSA units to meet the Reserve Requirement to include a $1/MMBTU increase in natural gas prices. This sensitivity scenario represents a more updated prediction of natural gas prices and corresponding generation offers.

The 2019 transmission topology used for the energy market simulation was derived from PJM's 2019 RTEP base case, including all upgrades identified as part of PJM's RTEP process up through and including those identified as part of the 2013 RTEP cycle. All backbone lines are included in the 2019 case as well as the PJM-approved Byron-Wayne 345 kV line. Specific transmission constraints were modeled for the analysis. These include thermal constraints and reactive interface constraints. Monitored thermal constraints include facility and contingency elements selected by examining historical PJM congestion events, reviewing other PJM planning studies, or by their representation in the NERC Book of Flowgates. PJM reactive interface limits are thermal limits derived from studying reactive conditions beyond which voltage violations may occur. The modeled interface limits were calculated based on voltage stability analysis, a review of historical values, and the inclusion of approved RTEP upgrades. In addition, only a subset of coordinated PJM/MISO market-to-market flowgates was included in the analysis. This subset of market-to-market flowgates represents historical events and is consistent with the Regional Market Efficiency process.

The energy market impacts were measured using the PROMOD production cost simulation tool that models an hourly security-constrained generation commitment and dispatch. The simulation tool modeled both the PJM and the MISO regions. The MISO model was derived from the 2013 interregional process with the addition of relevant MISO multi-value transmission projects. Due to time constraints, PJM did not have time to work with the MISO to ensure the model was the most current transmission representation for the MISO region.

The model includes multi-party transactions with commitment and dispatch hurdle rates defined between the PJM and MISO pools. This allows for economic transactions to flow between PJM and MISO within the simulation.

Finally, the ownership of the Quad Cities nuclear units was represented similar to the 2014 PJM RTEP Market Efficiency analysis with a shared ownership between PJM and MISO areas with respect to reporting results.

# VI. Results

## Reliability Impact Results

The reliability analyses identified significant thermal and voltage violations in the transmission systems owned by ComEd, American Electric Power, American Transmission Systems Inc., Duke Energy Ohio, Duke Energy Kentucky, Northern Indiana Public Service Company and Ameren Illinois for the various scenarios. The thermal and voltage violations were primarily on 345 kV and 138 kV facilities.

Thermal violations relate to the limit on the amount of electricity that can be transmitted over the electric transmission lines or related transmission facilities without overheating and degrading system components and potentially causing transmission outages. Voltage violations relate to the ability to maintain system voltages within specified limits to keep power flowing and the system stable. (To use an analogy related to water pressure, voltage violations occur when there is insufficient “pressure” in moving power across the lines leading to a possible voltage collapse, akin to pressure in a water pipe dropping to zero.)

*Byron Retirement*

The Byron retirement scenario identified 66 potential thermal violations. Of these 66 potential violations, there were 8 potential violations on 345 kV lines, 12 potential violations on 345/138 kV transformers, 44 potential violations on 138 kV lines, 1 138/69 kV transformer and 1 69 kV line. In addition, widespread voltage magnitude and voltage drop violations were identified that would likely require a combination of numerous installations of switched capacitors and dynamic reactive devices such as static VAR compensators, or SVCs.

*Byron and Quad Cities Retirement*

The Byron and Quad Cities retirement scenario identified 92 potential thermal violations. Of these 92 potential violations, there were 12 potential violations on 345 kV lines, 14 potential violations on 345/138 kV transformers, 64 potential violations on 138 kV lines, 1 138/69 kV transformer and 1 69 kV line. In addition, widespread voltage magnitude and voltage drop violations were identified that would likely require a combination of several thousand MVAR of switched capacitors and dynamic reactive devices such as SVCs.

*Byron, Quad Cities and Clinton Retirement*

The Byron, Quad Cities and Clinton retirement scenario identified 78 potential thermal violations. Of these 78 potential violations, there were 14 potential violations on 345 kV lines, 14 potential violations on 345/138 kV transformers, and, 50 potential violations on 138 kV lines. In addition, widespread voltage magnitude and voltage drop violations were identified that would likely require a combination of several thousand MVAR of switched capacitors and dynamic reactive devices such as SVCs.

*Preliminary Conclusions Regarding Transmission System Reliability*

Without very significant and costly transmission system upgrades, PJM's analysis concludes, the transmission system in Northern Illinois would be "unreliable" and would not satisfy mandatory reliability standards for the studied scenarios. Multiple transmission reinforcements would be required to maintain reliability. In general, the number and severity of potential reliability problems and, as a result, the required transmission upgrades, will increase for the scenarios where more generation is removed from the system.

It would likely take substantial time to correct the violations noted above, and it is unknown if the corrections could be completed in a timely manner, i.e. prior to the desired retirement of these facilities. Some corrections would require substantial construction activity and could significantly inconvenience Illinois citizens. Due to the time constraints of completing this analysis, PJM has not had an opportunity to evaluate the costs of the transmission upgrades necessary to have a reliable transmission system that would be required for each of the three scenarios. However, the costs would be significant – in the hundreds of millions of dollars or more.

## *Energy Market Impact Results*

PJM uses PROMOD software to project energy market impacts in future years. The PROMOD production cost simulation tool models an hourly security-constrained generation commitment and dispatch.

### Base Results

Table 2 provides the result of the base energy market analysis utilizing the PROMOD tool and the previously described base input assumptions. This table shows the impacts on carbon dioxide, sulfur dioxide, and nitrogen oxides, load payments and load-weighted wholesale locational marginal prices, or LMPs, for different retirement scenarios. These scenario simulations used the 2019 study year from the 2014 annual RTEP market efficiency cycle. The estimated reliability upgrades that would be necessary as a result of the different retirement scenarios have minimal impact on the results. This result is expected because most of the identified reliability upgrades did not impact the transmission facilities included in the model from the Base Market Efficiency case for 2019 study year.

As noted previously, PJM did not perform an exhaustive study of all applicable reliability criteria, including the ComEd criteria. Many of the identified reliability upgrades have minimal impact on the energy market simulation results because they may be local reactive upgrades, local thermal upgrades, or facilities not included in the model utilized in the 2019 market efficiency case. Table 2 shows only results of the different retirement scenarios using the modeled 2019 base study year.

Table 2 shows base results for effluents, in tons, for both the state of Illinois and the total PJM footprint. The increase in tons is significant for the state of Illinois as well as for the entire PJM footprint for each effluent. The impact of Clinton 1 being retired has a smaller impact on the PJM footprint, which is expected since this unit is not part of the PJM grid. In addition, the MISO model utilized in this study has not been thoroughly reviewed by PJM so results may be slightly skewed specifically for the Clinton 1 unit and Ameren-Illinois zone. The unavailability of the Byron, Quad Cities and Clinton units results in the largest increase in effluent tons for the state of Illinois.

## Base Results – Load Payments

The impact to load within ComEd, Ameren-Illinois and PJM was also measured with the different retirement scenarios as shown in Table 2. Load payments increased significantly in both the ComEd zone and the PJM footprint as more units were made unavailable. The worst case scenario with the Byron, Quad Cities and Clinton units being unavailable resulted in about a $752 million increase in load payments to the entire PJM footprint and about $307 million increase of load payments in the ComEd zone. Load payments along with load-weighted LMPs in the Ameren-Illinois zone had a smaller impact except for the scenarios for which the Clinton unit retired. The result is expected since the Clinton unit is located in MISO and not in the PJM RTO.

LMPs for the Commonwealth Edison zone were impacted the most for the scenario with the unavailability of the Byron, Quad Cities, and Clinton units. The results also reflect a best-case simulation because the PROMOD tool optimizes the data of the period of the analysis. In other words, although peak conditions, forced outages and unit bid data are represented in the cases, emergency, unpredictable and extreme situations cannot be represented. In addition, as described in the Energy Market Assumptions section of this report, the base simulations include generation that may not yet be in-service but which does have at least a signed Facilities Service Agreement. Not all units with signed FSAs will proceed to final completion, but within the base simulation these units may be dispatched. Therefore, as described in the Energy Market Assumptions section, PJM performed a sensitivity analysis with the FSA units removed from the generation model. In addition, since results can be significantly impacted by fuel prices and specifically natural gas prices, PJM performed a second sensitivity analysis with the natural gas prices increased by $1/MMBTU. This second sensitivity analysis was performed using the generation modeled that does not include FSA units. Results of both sensitivities are described in the next section of this report.

**Table 2:** 2019 Base Energy Market Impacts

| | | Nuclear Retirement Scenarios | | | | |
|---|---|---|---|---|---|---|
| Units | Byron 1 and 2 | x | x | x | | |
| | Quad Cities 1 and 2 | | x | x | | x |
| | Clinton 1 | | | x | x | |
| Delta in Effluent Tons | Illinois CO2 (millions) | 2.6 | 5.6 | 8.7 | 3.2 | 2.7 |
| | Illinois SO2 (thousands) | 3.4 | 6.6 | 10.5 | 4.2 | 3.1 |
| | Illinois NO x (thousands) | 2.3 | 4.4 | 6.3 | 2.1 | 2.0 |
| | PJM CO2 (millions) | 11.0 | 17.4 | 18.9 | 1.8 | 7.0 |
| | PJM SO2 (thousands) | 15.3 | 21.8 | 24.3 | 2.7 | 10.5 |
| | PJM NO x (thousands) | 7.7 | 11.9 | 13.2 | 1.6 | 5.1 |
| Delta in Load Payments ($millions) | AMIL | -$14.3 | -$5.8 | $23.3 | $25.0 | -$8.1 |
| | COMED | $198.4 | $290.0 | $306.8 | $13.1 | $103.3 |
| | PJM | $447.8 | $685.6 | $751.9 | $13.7 | $249.8 |
| Delta in Load Weighted LMP ($/MWh) | AMIL | -0.3 | -0.1 | 0.4 | 0.4 | -0.1 |
| | COMED | 1.7 | 2.5 | 2.7 | 0.1 | 0.9 |
| | PJM | 0.5 | 0.8 | 0.9 | 0.0 | 0.3 |

## Sensitivity Results

*Sensitivity Analysis with Removal of Generators with Facilities Service Agreements*

Table 3 shows results assuming the first sensitivity as described in this report. This sensitivity was to remove the FSA units from the model. FSA generation, although advanced in the interconnection process, has not committed to interconnecting to the system and as such is somewhat speculative in nature. Inclusion of FSA units in the base analysis is consistent with the PJM Regional Planning Market Efficiency process. It is added to market efficiency models to ensure reserve requirements are met throughout PJM's 15-year planning horizon and to match the RTEP transmission model, which includes necessary transmission upgrades required to satisfy reliability criteria with the FSA units interconnected. However, in the 2019 study year the FSA units are not actually necessary to meet the PJM reserve requirement. Therefore excess generation is being modeled when the FSA units are included.

The result of the analysis with the FSA units removed mainly impacted the Load Payments and LMP prices compared to the original base case with the FSA units included. Effluents, in tons, continue to increase significantly for the state of Illinois as well as for the entire PJM footprint for each effluent. However, the increase is comparable to the base case for which FSA units were included. The removal of the FSA units had a more significant impact on the load payments and LMP prices. The load payments for the Commonwealth Edison zone increased by about $340 million while the load-weighted LMP prices increased by about $3/MWh for the scenario with the Byron, Quad Cities, and Clinton units all retired. In addition, the PJM RTO load payments increased by about $968 million while the load-weighted LMP prices increased by about $1.1/MWh for the scenario with the Byron, Quad Cities, and Clinton units all retired.

**Table 3:** 2019 Energy Market Impacts with Facilities Service Agreements (FSAs) Removed

| | | Nuclear Retirement Scenarios | | | | |
|---|---|---|---|---|---|---|
| Units | Byron 1 and 2 | x | x | x | | |
| | Quad Cities 1 and 2 | | x | x | | x |
| | Clinton 1 | | | x | x | |
| Delta in Effluent Tons | Illinois CO2 (millions) | 3.3 | 6.1 | 7.9 | 2.4 | 3.1 |
| | Illinois SO2 (thousands) | 3.7 | 6.0 | 7.7 | 2.9 | 3.2 |
| | Illinois NO x (thousands) | 2.2 | 3.7 | 4.5 | 1.0 | 1.7 |
| | PJM CO2 (millions) | 11.5 | 17.9 | 18.2 | 0.6 | 7.2 |
| | PJM SO2 (thousands) | 13.7 | 22.0 | 22.1 | 0.8 | 9.1 |
| | PJM NO x (thousands) | 7.7 | 12.1 | 12.3 | 0.2 | 4.9 |
| Delta in Load Payments ($millions) | AMIL | -$6.3 | $4.5 | $43.1 | $39.4 | -$2.0 |
| | COMED | $224.2 | $322.7 | $339.6 | $22.0 | $108.0 |
| | PJM | $556.1 | $932.8 | $968.5 | $57.4 | $283.9 |
| Delta in Load Weighted LMP ($/MWh) | AMIL | -0.1 | 0.1 | 0.8 | 0.7 | 0.0 |
| | COMED | 2.0 | 2.8 | 3.0 | 0.2 | 0.9 |
| | PJM | 0.6 | 1.1 | 1.1 | 0.1 | 0.3 |

*Sensitivity Analysis with Natural Gas Prices Increased by $1/MMBTU*

Table 4 shows results assuming the second sensitivity as described in this report. The second sensitivity analysis was to modify the first sensitivity to include a $1/MMBTU increase in natural gas prices. This sensitivity analysis represents a more updated prediction of natural gas prices and corresponding generation offers. As expected, the results are more significant with the increase in natural gas prices. In particular, the most significant impact was to the load payments and the LMP prices. Effluent tons remain comparable to the original base case. The state of Illinois $CO_2$ tons increased by about 7 million tons and the PJM $CO_2$ tons increased by about 16.1 million tons with the increase in natural gas prices. The load payments for the Commonwealth Edison zone increased by about $437 million, while the load-weighted LMP prices increased by about $3.8/MWh for the scenario with the Byron, Quad Cities, and Clinton units all retired. In addition, the PJM RTO load payments increased by about $1.3 billion, while the load-weighted LMP prices increased by about $1.5/MWh for the scenario with the Byron, Quad Cities, and Clinton units all retired.

**Table 4:** 2019 Energy Market Impacts with Natural Gas Prices increased by $1/MMBTU

| | | Nuclear Retirement Scenarios | | | | |
|---|---|---|---|---|---|---|
| Units | Byron 1 and 2 | x | x | x | | |
| | Quad Cities 1 and 2 | | x | x | | x |
| | Clinton 1 | | | x | x | |
| Delta in Effluent Tons | Illinois CO2 (millions) | 2.9 | 5.3 | 7.0 | 2.1 | 2.6 |
| | Illinois SO2 (thousands) | 3.6 | 5.6 | 7.0 | 2.6 | 2.8 |
| | Illinois NO x (thousands) | 2.0 | 3.3 | 3.9 | 0.9 | 1.3 |
| | PJM CO2 (millions) | 10.2 | 15.4 | 16.1 | 0.6 | 6.1 |
| | PJM SO2 (thousands) | 10.6 | 15.8 | 15.8 | (0.3) | 6.3 |
| | PJM NO x (thousands) | 6.9 | 10.3 | 10.4 | (0.1) | 4.2 |
| Delta in Load Payments ($millions) | AMIL | $12.2 | $38.5 | $85.9 | $57.1 | $15.2 |
| | COMED | $302.0 | $407.3 | $436.8 | $46.2 | $140.9 |
| | PJM | $806.0 | $1,259.4 | $1,307.5 | $129.7 | $421.4 |
| Delta in Load Weighted LMP ($/MWh) | AMIL | 0.2 | 0.7 | 1.5 | 1.0 | 0.3 |
| | COMED | 2.7 | 3.6 | 3.8 | 0.4 | 1.2 |
| | PJM | 0.9 | 1.5 | 1.5 | 0.2 | 0.5 |

## VII. Conclusions

The PJM analyses of both the reliability, energy market and certain environmental impacts of the retirement of up to five nuclear units at three nuclear power stations show significant impacts. The reliability analyses of the potential retirement of five nuclear units identified significant thermal and voltage violations on the transmission system. It would likely take substantial time to correct the reliability violations, and it is unknown if the corrections could be completed in a timely manner. Some corrections could inconvenience Illinois citizens. The reliability costs would be significant – in the hundreds of millions of dollars or more.

The retirement of nuclear units that the Illinois commission asked PJM to evaluate would likely result in 2019 in increased carbon dioxide emissions of up to 18.9 million tons across the PJM region and up to 8.7 million tons for the state of Illinois based on the different scenarios and sensitivities performed in this analysis. Locational marginal prices would likely increase between $2.70 and $3.80 per megawatt-hour in the Commonwealth Edison zone and between $0.90 and $1.50 per megawatt-hour in PJM based on the different scenarios and sensitivities performed for this analysis. In addition, load payments would increase between $307 million and $437 million in the Commonwealth Edison zone and between $752 million and $1.3 billion in PJM based on the different scenarios and sensitivities performed for this analysis.

# MISO RESPONSE TO THE ILLINOIS COMMERCE COMMISSION REQUEST TO STUDY NUCLEAR RETIREMENTS

November 2014

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## I. OVERVIEW

MISO provides this report to the Illinois Commerce Commission (ICC) as a response to a formal request from the ICC to study and analyze the impacts of potential economic retirements of Illinois' nuclear generating units. The request was to assess the economic and reserve margin impacts for different nuclear plant retirement scenarios. The analyses were based on assumptions about future fuel prices, peak loads and generation mixes used in the MTEP 15 (2015 MISO Transmission Expansion Plan) study Business As Usual (BAU) future. Changes in any of those assumptions could result in different expected impacts. MISO performed a natural gas sensitivity substituting in the high gas price and trajectory from the MTEP 15 *high growth future*. The retirements were agreed to be modeled for the year 2019 through the rest of the study period.

## II. MISO'S RESPONSIBILITIES

MISO is an independent, not-for-profit Regional Transmission Organization (RTO) responsible for maintaining reliable transmission of power in 15 U.S. states and the Canadian province of Manitoba. With more than 400 registered market participants and more than 65,000 miles of interconnected high voltage transmission lines and $32 billion in annual energy transactions, MISO is one of the largest RTOs in North America providing an essential link in the safe, cost-effective delivery of power to consumers. MISO is regulated by the Federal Energy Regulatory Commission (FERC) and doesn't own physical transmission or generating assets.

In Illinois, MISO works with its member companies, such as Ameren, Dynegy and Exelon, and with our neighboring RTO, PJM, to coordinate the reliable and economic flow of electricity between our two footprints. MISO's member companies serve approximately 1.2 million electric customers over 4,500 miles of transmission lines in Illinois.

Our responsibilities include reliable system operations through:

| | |
|---|---|
| **REAL-TIME OPERATIONS** | • **Safe and reliable flow of electricity across the grid- "*Keeping the Lights On*"** |
| **WHOLESALE MARKET ADMINISTRATION** | • **Open energy markets, including centralized scheduling and economic dispatch of generation to support reliable and efficient operation** |
| **TRANSMISSION PLANNING** | • **Safe, reliable and economically efficient transmission expansion** |

## III. ILLINOIS COMMERCE COMMISSION'S STUDY REQUEST

MISO strives to provide a uniform understanding among its stakeholders and policymakers regarding the impact of critical public policy issues such as these. On May 29 2014, the Illinois House of Representative adopted House Resolution 1146 (HR1146) with a focus on nuclear power. The resolution specifically urged the Illinois Commerce Commission

> "to prepare a report examining the State's and grid operators' ability to expand transmissions to allow Illinois to transport clean electricity to other parts of the nation, as well as any legislative impediments, and the impact on residential, commercial, and industrial electric rates from the premature closure of Illinois' nuclear power plants."

On October 2, 2014, MISO received a formal request from the ICC requesting that MISO perform analyses of the impacts of Illinois nuclear power plant retirements in an effort to assist the ICC's completion of a rate impact assignment provided for in HR 1146. To that end, the ICC requested that MISO examine and model the following:

- Unexpected nuclear power plant retirements on wholesale prices and expenditures to serve load
- The impact of such retirements, assuming some market responses (for example, replacement investments in new generation infrastructure)

The ICC requested that MISO conduct analyses using EGEAS[1] with a study framework provided in Table 1 below (where In or Out depicts whether or not at unit was online in that respective sensitivity. ):

[1] EGEAS is a strategic assessment model used by MISO for policy and resource assessments.

**Table 1- MISO Analysis per ICC Request**

| **MISO** | **BAU** | **1** | | | | |
|---|---|---|---|---|---|---|
| **Clinton 1** | In | Out | | | | |
| **PJM** | BAU | 1 | 2 | 3 | 4 | 5 |
| Quad Cities 1 | In | Out | In | In | In | In |
| Quad Cities 2 | In | Out | In | In | In | In |
| Byron 1 | In | In | Out | In | In | In |
| Byron 2 | In | In | Out | In | In | In |
| LaSalle 1 | In | In | In | Out | In | In |
| LaSalle 2 | In | In | In | Out | In | In |
| Braidwood 1 | In | In | In | In | Out | In |
| Braidwood 2 | In | In | In | In | Out | In |
| Dresden 2 | In | In | In | In | In | Out |
| Dresden 3 | In | In | In | In | In | Out |

The ICC further requested the detailed output from MISO's EGEAS analysis in order to further understand the results and a firm context for the implications.

### A. EGEAS Model

EGEAS is a strategic assessment model used by MISO for policy and resource assessments. It provides an assessment/forecast of long-term regional requirements, and an optimization of the resources that will be utilized to serve them for the entire RTO system. These costs are calculated annually over a 20-year study period plus 40-year extension period. EGEAS has a minimal run time, which enables numerous sensitivities to be examined simultaneously.

EGEAS can perform this type of sophisticated and complex analysis with multiple input variables and alternatives which can include elements like generation, transmission and demand response alternatives. This modeling tool helps MISO to study the impacts of retirement decisions on both capital requirements and long-term production costs. Further, EGEAS can provide "optimal" solutions according to reliability, reserve margin(s), or emission constraints and can produce a ranked portfolio of resources based on both capital and production costs.

The costs captured in the EGEAS model reflect the costs of replacement capital (capital fixed charges), the differences in the production costs (fuel costs, variable operating & maintenance expense (O&M)), fixed O&M, and the generic detailed costs modeled.

### B. Study Assumptions

Per the recommendation from the ICC, MISO used the MTEP 15 BAU case as the base case for this analysis and assumed a retirement date of June 1, 2019 for the sensitivities in the diagram below. A high gas cost sensitivity from the MTEP 15 *high growth future* was also evaluated in order to analyze the impact of natural gas on the overall study results. Using varying gas prices helps provide context around a highly volatile uncertainty variable.

A 20-year study period of 2014 – 2033 with a 40- year extension period is used in the EGEAS model for the purposes of being able to optimize generation dispatch and resource selection in the up-front 20-year study period. The costs incurred in the extension period are not captured in the results shown in this report.

The study evaluates the avoided cost of nuclear generation retirements in Illinois and does not represent an evaluation of marginal costs. That is to say it attempts to capture the changes in costs, not the actual dollar value of energy for that specific sensitivity.

Table 2 below, provides an overview of the assumptions used in this analysis. These assumptions were developed in our open stakeholder study process for MTEP. The Base Case in the table reflects what was used in the Business as Usual (BAU) future scenario with the Henry Hub gas forecasts used in the base cases and the high gas sensitivity cases.

**Table 2 - MISO Modeling Assumptions**

| MTEP15 UNCERTAINTY VARIABLES | | | | | |
|---|---|---|---|---|---|
| **Uncertainty** | **Unit** | **Base Case** | | | |
| **New Generation Capital Costs[1]** | | | | | |
| Coal | ($/KW) | **2,996** | | | |
| CC | ($/KW) | **1,045** | | | |
| CT | ($/KW) | **690** | | | |
| Nuclear | ($/KW) | **5,647** | | | |
| Wind-Onshore | ($/KW) | **2,034** | | | |
| IGCC | ($/KW) | **3,864** | | | |
| IGCC w/ CCS | ($/KW) | **6,738** | | | |
| CC w/ CCS | ($/KW) | **2,139** | | | |
| Pumped Storage Hydro | ($/KW) | **5,400** | | | |
| Compressed Air Energy Storage | ($/KW) | **1,276** | | | |
| Photovoltaic | ($/KW) | **2,966** | | | |
| Biomass | ($/KW) | **4,201** | | | |
| Conventional Hydro | ($/KW) | **2,998** | | | |
| Wind-Offshore | ($/KW) | **6,362** | | | |
| **Demand and Energy** | | | | | |
| Demand Growth Rate[2] | % | **0.80%** | | | |
| Energy Growth Rate[3] | % | **0.80%** | | | |
| Demand Response Level[4] | % | **State mandates only** | | | |
| Energy Efficiency Level[4] | % | **State mandates only** | | | |
| **Natural Gas** | | | | | |
| Natural Gas[5] | ($/MMBtu) | **Bentek forecast from Phase III Gas Study** | | | |
| **Fuel Prices (Starting Values)** | | | **Fuel Price Escalation** | | |
| Oil | ($/MMBtu) | **Powerbase default[6]** | % | 2.0 | **2.5** |
| Coal | ($/MMBtu) | **Powerbase default[7]** | % | 2.0 | **2.5** |
| Uranium | ($/MMBtu) | **1.14** | % | 2.0 | **2.5** |
| **Emissions Costs** | | | | | |
| $SO_2$ | ($/ton) | **0** | | | |
| $NO_x$ | ($/ton) | **0** | | | |
| $CO_2$ | ($/ton) | **0** | | | |
| **Other Variables** | | | | | |
| Inflation | % | **2.5** | | | |
| Retirements | MW | **Related** | | | |
| Renewable Portfolio Standards | % | **State mandates only** | | | |

| Gas Prices | BAU | High Gas |
|---|---|---|
| **Inflation Level** | MID (2.5%) Inflation | HIGH (4.0%) Inflation |
| **Units** | ($/MMBtu) | ($/MMBtu) |
| **2014** | 4.30 | 5.16 |
| **2015** | 4.67 | 5.69 |
| **2016** | 4.94 | 6.10 |
| **2017** | 5.31 | 6.66 |
| **2018** | 5.53 | 7.04 |
| **2019** | 5.93 | 7.65 |
| **2020** | 6.14 | 8.04 |
| **2021** | 6.31 | 8.38 |
| **2022** | 6.24 | 8.42 |
| **2023** | 6.36 | 8.70 |
| **2024** | 6.50 | 9.01 |
| **2025** | 6.64 | 9.36 |
| **2026** | 6.84 | 9.77 |
| **2027** | 7.02 | 10.18 |
| **2028** | 7.21 | 10.61 |
| **2029** | 7.38 | 11.01 |
| **2030** | 7.58 | 11.47 |
| **2031** | 7.75 | 11.91 |
| **2032** | 7.98 | 12.43 |
| **2033** | 8.18 | 12.93 |

[1] *All costs are overnight construction costs in 2014 dolla*
[2] *Mid value for demand growth rate is the Module-E 50*
[3] *Mid value for energy growth rate is the Module-E ene*
[4] *MTEP13 modeled state mandates and goals for DR &*
[5] *Prices reflect the Henry Hub natural gas price*
[6] *Powerbase default for oil is $19.39/MMBtu; based on*
[7] *Powerbase range for coal is $1 to $4, with an average*
[8] *11,600 MW value is based on MTEP13 database*

# IV. STUDY FINDINGS[2]

## A. Retirement Impacts in MISO

Based on our study, the total cost impacts for the MISO market were $236 and $341 million annually for the Clinton Plant under the normal and high gas sensitivities. The replacement costs associated with Clinton's retirement are about $1.2 billion and will require 1200 MW of Combustions Turbines (CTs). Table 3 below shows the cost deltas between the total net present value and annualized values of the capital fixed charges, production costs, and fixed operation & maintenance costs between the base case and the Clinton retirement case under the base gas assumption in the MISO EGEAS model.

**Table 3 - MISO Total and Annualized Cost Deltas[3]**

| Sensitivity | Retired (MW) | Build Deltas (MW) | | Cost Deltas ($M) | |
|---|---|---|---|---|---|
| | | CC | CT | Total | Annual |
| ***MISO Nuclear Resources with Base Case Gas Sensitivities*** | | | | | |
| Clinton | 1077 | 0 | 1200 | $3,674 | $236 |
| ***MISO Nuclear Resources with High Case Gas Sensitivities*** | | | | | |
| Clinton | 1077 | 1200 | 0 | $5,314 | $341 |
| ***MISO Nuclear Resources with High minus Base Gas Sensitivities*** | | | | | |
| Clinton | 1077 | | | $1,640 | $105 |

[2] Appendix A includes tables showing annualized costs on a year-by-year and unit-by-unit basis,
[3] Production Costs, Capital Fixed Charges, Fixed O&M.

### B. Retirement Impacts in PJM

For PJM, the total cost impacts ranged from $203 million to $554 million annually. Table 4 below shows the cost delta between the total net present value and annualized costs of the capital fixed charges, production costs, and fixed operation & maintenance costs between the PJM EGEAS base case and nuclear retirement sensitivity cases for the PJM units.

**Table 4 - PJM Total and Annualized Cost Deltas**

| Case | Retired (MW) | Build Deltas (MW) | | Cost Deltas ($M) | |
|---|---|---|---|---|---|
| | | CC | CT | Total | Annual |
| ***PJM Nuclear Resources with Base Case Gas Sensitivities*** | | | | | |
| Quad Cities | 1345 | 0 | 1200 | $3,160 | $203 |
| Byron | 2346 | 0 | 2400 | $5,779 | $371 |
| LaSalle | 2274 | 0 | 2400 | $5,579 | $358 |
| Braidwood | 2384 | 0 | 2400 | $5,880 | $377 |
| Dresden | 1917 | 0 | 2400 | $4,661 | $299 |
| ***PJM Nuclear Resources with High Case Gas Sensitivities*** | | | | | |
| Quad Cities | 1345 | 1200 | 0 | $4,745 | $304 |
| Byron | 2346 | 0 | 2400 | $8,374 | $537 |
| LaSalle | 2274 | 0 | 2400 | $8,098 | $519 |
| Braidwood | 2384 | 1200 | 1200 | $8,639 | $554 |
| Dresden | 1917 | 2400 | 0 | $7,039 | $452 |
| ***PJM Nuclear Resources with High minus Base Gas Sensitivities*** | | | | | |
| Quad Cities | 1345 | | | $1,585 | $102 |
| Byron | 2346 | | | $2,595 | $166 |
| LaSalle | 2274 | | | $2,520 | $162 |
| Braidwood | 2384 | | | $2,759 | $177 |
| Dresden | 1917 | | | $2,378 | $153 |

### C. MISO and PJM Cost Deltas

Below in Table 5, the 2019 deltas are presented for the various costs captured in EGEAS; Production Cost (PC), Fixed Operation & Maintenance (Fixed O&M), and the Capital Fixed Charges (Cap Fixed). In the MISO cases, the Clinton retirement sensitivity changes the capacity selections in the 2019 planning year, so a delta in the capital fixed charges is shown in the table. The expansion differences don't occur in the PJM model sensitivities until 2022 or 2023, therefore no deltas in capital costs are seen in 2019.

**Table 5 - 2019 MISO and PJM Cost Deltas in $M in 2019 Dollars**

| Case | PC Delta | Fixed O&M Delta | Cap Fixed Delta |
|---|---|---|---|
| MISO_BAU | 0 | 0 | 0 |
| Clinton_BAU | 227 | -68 | 160 |
| MISO_HG | 0 | 0 | 0 |
| Clinton_HG | 304 | -68 | 160 |
| **Cases** | **PC Delta** | **Fixed O&M Delta** | **Cap Fixed Delta** |
| PJM_BAU | 0 | 0 | 0 |
| QuadCities | 245 | -107 | 0 |
| Byron | 445 | -186 | 0 |
| LaSalle | 427 | -181 | 0 |
| Braidwood | 451 | -189 | 0 |
| Dresden | 349 | -152 | 0 |
| PJM_HG | 0 | 0 | 0 |
| QuadCities_HG | 325 | -107 | 0 |
| Byron_HG | 588 | -186 | 0 |
| LaSalle_HG | 566 | -181 | 0 |
| Braidwood_HG | 593 | -189 | 0 |
| Dresden_HG | 465 | -152 | 0 |

### D. Impact of Gas Prices

MISO has observed that on both systems, there is a general trend between natural gas price sensitivities and a shift from CTs to combined cycle units (CCs) despite the fact that CCs have higher capital costs upon install. This is attributable to the lower heat rate of CCs. As natural gas becomes more costly, the fuel savings of CCs becomes more advantageous over the additional costs incurred for construction.

Additionally, these units produce more energy and achieve a higher reserve contribution on peak. In the lower natural gas price cases, depending on demand and the needs associated with reserve capacity, CTs will be selected and dispatched more frequently.

For both model run results, the replacement capacity and costs are approximately commensurate with the amount of capacity retired. In the detailed model output data, the deltas between the various cost components are shown per sensitivity and per year. While the production cost (including fuel costs and variable O&M) and capital fixed charges are higher in the retirement scenarios, the fixed O&M does generally go down replacing nuclear with CCs or CTs. The fuel costs and energy contributions by fuel type also fluctuate accordingly. This is important to note because it means that not all costs increase, but that these results portray the net of all changes that EGEAS can capture.

## V. CONCLUSIONS

The MISO analyses of the retirement impacts of Clinton Generating Station and Braidwood, Byron, Dresden, LaSalle and Quad Cities show significant cost impacts in the 2014 – 2033 study period.

MISO projects that load payments would be between $236 and $341 million annually, as a result of the Clinton plant retiring, and between $203 million and $554 million annually for PJM based on the different scenarios and sensitivities performed for this analysis.

# APPENDIX A

## MISO Results:

| Case | YEAR | New CC | New CT | | YEAR | Production Cost | Fixed O+M Cost | Capital Fixed Charges | Detailed Costs |
|---|---|---|---|---|---|---|---|---|---|
| **MISO_BAU** | | | | | **Total (2014 $)** | **$ 313,367** | **$ 81,796** | **$ 70,946** | **$ 37,967** |
| **MISO_BAU** | | | | | **Annualized** | **$ 20,102** | **$ 5,247** | **$ 4,551** | **$ 2,436** |
| MISO_BAU | 2014 | 0 | 0 | | 2014 | 13,436 | 3,883 | 1,052 | - |
| MISO_BAU | 2015 | 0 | 0 | | 2015 | 14,308 | 4,197 | 1,538 | 2,996 |
| MISO_BAU | 2016 | 0 | 1200 | | 2016 | 15,173 | 4,074 | 2,492 | 2,503 |
| MISO_BAU | 2017 | 0 | 0 | | 2017 | 15,916 | 4,190 | 2,559 | 2,503 |
| MISO_BAU | 2018 | 0 | 1200 | | 2018 | 16,437 | 4,360 | 3,082 | 2,503 |
| MISO_BAU | 2019 | 0 | 1200 | | 2019 | 17,167 | 4,496 | 3,253 | 2,503 |
| MISO_BAU | 2020 | 0 | 1200 | | 2020 | 17,887 | 4,631 | 3,555 | 2,503 |
| MISO_BAU | 2021 | 1200 | 0 | | 2021 | 18,387 | 4,781 | 3,965 | 2,503 |
| MISO_BAU | 2022 | 1200 | 0 | | 2022 | 18,948 | 4,909 | 4,105 | 2,503 |
| MISO_BAU | 2023 | 1200 | 0 | | 2023 | 19,582 | 5,040 | 4,224 | 2,503 |
| MISO_BAU | 2024 | 1200 | 0 | | 2024 | 20,268 | 5,175 | 4,358 | 2,503 |
| MISO_BAU | 2025 | 1200 | 0 | | 2025 | 20,992 | 5,323 | 4,714 | 2,503 |
| MISO_BAU | 2026 | 0 | 0 | | 2026 | 21,374 | 5,630 | 6,706 | 2,503 |
| MISO_BAU | 2027 | 0 | 1200 | | 2027 | 22,097 | 5,796 | 6,805 | 2,503 |
| MISO_BAU | 2028 | 0 | 2400 | | 2028 | 23,052 | 5,965 | 6,928 | 2,503 |
| MISO_BAU | 2029 | 0 | 1200 | | 2029 | 23,855 | 6,142 | 7,000 | 2,503 |
| MISO_BAU | 2030 | 0 | 1200 | | 2030 | 24,725 | 6,308 | 6,926 | 2,503 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| MISO_BAU | 2031 | 0 | 1200 | | 2031 | 25,773 | 6,479 | 6,836 | 2,503 |
| MISO_BAU | 2032 | 0 | 2400 | | 2032 | 26,743 | 6,690 | 7,161 | 2,503 |
| MISO_BAU | 2033 | 0 | 1200 | | 2033 | 27,629 | 6,872 | 7,066 | 2,503 |
| MISO_BAU | SUM: | 6000 | 15600 | | EXT. | 98,103 | 23,919 | 18,032 | 517 |
| **Clinton_BAU** | | | | | **Total (2014 $)** | **$ 316,788** | **$ 80,924** | **$ 72,071** | **$ 37,967** |
| **Clinton_BAU** | | | | | **Annualized** | **$ 20,321** | **$ 5,191** | **$ 4,623** | **$ 2,436** |
| Clinton_BAU | 2014 | 0 | 0 | | 2014 | 13,436 | 3,883 | 1,052 | - |
| Clinton_BAU | 2015 | 0 | 0 | | 2015 | 14,308 | 4,197 | 1,538 | 2,996 |
| Clinton_BAU | 2016 | 0 | 1200 | | 2016 | 15,173 | 4,074 | 2,492 | 2,503 |
| Clinton_BAU | 2017 | 0 | 0 | | 2017 | 15,916 | 4,190 | 2,559 | 2,503 |
| Clinton_BAU | 2018 | 0 | 1200 | | 2018 | 16,437 | 4,360 | 3,082 | 2,503 |
| Clinton_BAU | 2019 | 0 | 2400 | | 2019 | 17,394 | 4,428 | 3,412 | 2,503 |
| Clinton_BAU | 2020 | 0 | 1200 | | 2020 | 18,144 | 4,562 | 3,709 | 2,503 |
| Clinton_BAU | 2021 | 1200 | 0 | | 2021 | 18,634 | 4,710 | 4,112 | 2,503 |
| Clinton_BAU | 2022 | 1200 | 0 | | 2022 | 19,199 | 4,836 | 4,245 | 2,503 |
| Clinton_BAU | 2023 | 1200 | 0 | | 2023 | 19,825 | 4,966 | 4,358 | 2,503 |
| Clinton_BAU | 2024 | 0 | 2400 | | 2024 | 20,569 | 5,110 | 4,566 | 2,503 |
| Clinton_BAU | 2025 | 1200 | 0 | | 2025 | 21,293 | 5,256 | 4,914 | 2,503 |
| Clinton_BAU | 2026 | 0 | 0 | | 2026 | 21,685 | 5,561 | 6,896 | 2,503 |
| Clinton_BAU | 2027 | 0 | 0 | | 2027 | 22,414 | 5,711 | 6,792 | 2,503 |
| Clinton_BAU | 2028 | 0 | 2400 | | 2028 | 23,393 | 5,878 | 6,913 | 2,503 |
| Clinton_BAU | 2029 | 0 | 1200 | | 2029 | 24,192 | 6,053 | 6,985 | 2,503 |
| Clinton_BAU | 2030 | 0 | 1200 | | 2030 | 25,087 | 6,217 | 6,911 | 2,503 |
| Clinton_BAU | 2031 | 0 | 2400 | | 2031 | 26,141 | 6,401 | 7,035 | 2,503 |
| Clinton_BAU | 2032 | 0 | 1200 | | 2032 | | 6,594 | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | 27,147 | | 7,131 | 2,503 |
| Clinton_BAU | 2033 | 0 | 1200 | | 2033 | 28,020 | 6,773 | 7,033 | 2,503 |
| Clinton_BAU | SUM: | 4800 | 18000 | | EXT. | 99,492 | 23,569 | 18,097 | 517 |
| **MISO_HG** | | | | | **Total (2014 $)** | **$ 339,126** | **$ 81,796** | **$ 72,103** | **$ 37,967** |
| **MISO_HG** | | | | | **Annualized** | **$ 21,754** | **$ 5,247** | **$ 4,625** | **$ 2,436** |
| MISO_HG | 2014 | 0 | 0 | | 2014 | 13,625 | 3,883 | 1,052 | - |
| MISO_HG | 2015 | 0 | 0 | | 2015 | 14,566 | 4,197 | 1,538 | 2,996 |
| MISO_HG | 2016 | 0 | 1200 | | 2016 | 15,771 | 4,074 | 2,492 | 2,503 |
| MISO_HG | 2017 | 0 | 0 | | 2017 | 16,648 | 4,190 | 2,559 | 2,503 |
| MISO_HG | 2018 | 0 | 1200 | | 2018 | 17,264 | 4,360 | 3,082 | 2,503 |
| MISO_HG | 2019 | 0 | 1200 | | 2019 | 18,144 | 4,496 | 3,253 | 2,503 |
| MISO_HG | 2020 | 0 | 1200 | | 2020 | 19,033 | 4,631 | 3,555 | 2,503 |
| MISO_HG | 2021 | 1200 | 0 | | 2021 | 19,637 | 4,781 | 3,965 | 2,503 |
| MISO_HG | 2022 | 1200 | 0 | | 2022 | 20,334 | 4,909 | 4,105 | 2,503 |
| MISO_HG | 2023 | 1200 | 0 | | 2023 | 21,128 | 5,040 | 4,224 | 2,503 |
| MISO_HG | 2024 | 1200 | 0 | | 2024 | 22,009 | 5,175 | 4,358 | 2,503 |
| MISO_HG | 2025 | 1200 | 0 | | 2025 | 22,932 | 5,323 | 4,714 | 2,503 |
| MISO_HG | 2026 | 0 | 0 | | 2026 | 23,334 | 5,630 | 6,706 | 2,503 |
| MISO_HG | 2027 | 1200 | 0 | | 2027 | 24,228 | 5,798 | 6,912 | 2,503 |
| MISO_HG | 2028 | 1200 | 0 | | 2028 | 25,458 | 5,955 | 6,942 | 2,503 |
| MISO_HG | 2029 | 1200 | 0 | | 2029 | 26,442 | 6,134 | 7,126 | 2,503 |
| MISO_HG | 2030 | 0 | 2400 | | 2030 | 27,618 | 6,316 | 7,257 | 2,503 |
| MISO_HG | 2031 | 1200 | 0 | | 2031 | 29,002 | 6,489 | 7,272 | 2,503 |
| MISO_HG | 2032 | 1200 | 0 | | 2032 | 30,274 | 6,687 | 7,481 | 2,503 |
| MISO_HG | 2033 | 1200 | 0 | | 2033 | 31,428 | 6,872 | 7,496 | 2,503 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| MISO_HG | SUM: | 13200 | 7200 | EXT. | 121,022 | 23,919 | 18,884 | 517 |
| **Clinton_HG** | | | | **Total (2014 $)** | **$ 343,246** | **$ 80,923** | **$ 74,170** | **$ 37,967** |
| **Clinton_HG** | | | | **Annualized** | **$ 22,018** | **$ 5,191** | **$ 4,758** | **$ 2,436** |
| Clinton_HG | 2014 | 0 | 0 | 2014 | 13,625 | 3,883 | 1,052 | - |
| Clinton_HG | 2015 | 0 | 0 | 2015 | 14,566 | 4,197 | 1,538 | 2,996 |
| Clinton_HG | 2016 | 0 | 1200 | 2016 | 15,771 | 4,074 | 2,492 | 2,503 |
| Clinton_HG | 2017 | 0 | 0 | 2017 | 16,648 | 4,190 | 2,559 | 2,503 |
| Clinton_HG | 2018 | 0 | 1200 | 2018 | 17,264 | 4,360 | 3,082 | 2,503 |
| Clinton_HG | 2019 | 0 | 2400 | 2019 | 18,448 | 4,428 | 3,412 | 2,503 |
| Clinton_HG | 2020 | 1200 | 0 | 2020 | 19,330 | 4,564 | 3,799 | 2,503 |
| Clinton_HG | 2021 | 1200 | 0 | 2021 | 19,925 | 4,712 | 4,199 | 2,503 |
| Clinton_HG | 2022 | 1200 | 0 | 2022 | 20,640 | 4,838 | 4,328 | 2,503 |
| Clinton_HG | 2023 | 1200 | 0 | 2023 | 21,436 | 4,968 | 4,437 | 2,503 |
| Clinton_HG | 2024 | 1200 | 0 | 2024 | 22,349 | 5,101 | 4,562 | 2,503 |
| Clinton_HG | 2025 | 1200 | 0 | 2025 | 23,275 | 5,247 | 4,909 | 2,503 |
| Clinton_HG | 2026 | 0 | 0 | 2026 | 23,701 | 5,551 | 6,892 | 2,503 |
| Clinton_HG | 2027 | 1200 | 0 | 2027 | 24,583 | 5,718 | 7,090 | 2,503 |
| Clinton_HG | 2028 | 1200 | 0 | 2028 | 25,867 | 5,873 | 7,111 | 2,503 |
| Clinton_HG | 2029 | 1200 | 0 | 2029 | 26,862 | 6,050 | 7,286 | 2,503 |
| Clinton_HG | 2030 | 0 | 2400 | 2030 | 28,058 | 6,230 | 7,409 | 2,503 |
| Clinton_HG | 2031 | 1200 | 0 | 2031 | 29,457 | 6,401 | 7,415 | 2,503 |
| Clinton_HG | 2032 | 1200 | 0 | 2032 | 30,778 | 6,597 | 7,615 | 2,503 |
| Clinton_HG | 2033 | 1200 | 0 | 2033 | 31,903 | 6,779 | 7,621 | 2,503 |
| Clinton_HG | SUM: | 14400 | 7200 | EXT. | 123,205 | 23,588 | 19,312 | 517 |

## PJM Results:

| Cases | YEAR | New CC | New CT | | YEAR | Production Cost | Fixed O+M Cost | Capital Fixed Charges | Detailed Costs |
|---|---|---|---|---|---|---|---|---|---|
| PJM_BAU | | | | | **Total (2014 $)** | **$ 352,101** | **$ 138,786** | **$ 243,954** | **$ 23,403** |
| PJM_BAU | | | | | **Annualized** | **$ 23,506** | **$ 8,903** | **$ 15,649** | **$ 1,501** |
| PJM_BAU | 2014 | 0 | 0 | | 2014 | 17,646 | 5,309 | 1,085 | - |
| PJM_BAU | 2015 | 0 | 0 | | 2015 | 18,616 | 5,620 | 3,316 | 1,660 |
| PJM_BAU | 2016 | 0 | 2400 | | 2016 | 18,177 | 6,510 | 10,534 | 1,560 |
| PJM_BAU | 2017 | 0 | 0 | | 2017 | 18,637 | 6,981 | 11,989 | 1,555 |
| PJM_BAU | 2018 | 0 | 0 | | 2018 | 19,088 | 7,450 | 13,176 | 1,555 |
| PJM_BAU | 2019 | 0 | 0 | | 2019 | 19,463 | 7,808 | 14,251 | 1,555 |
| PJM_BAU | 2020 | 0 | 0 | | 2020 | 20,062 | 8,103 | 15,453 | 1,555 |
| PJM_BAU | 2021 | 0 | 0 | | 2021 | 20,272 | 8,391 | 16,553 | 1,555 |
| PJM_BAU | 2022 | 0 | 0 | | 2022 | 20,651 | 8,675 | 17,325 | 1,555 |
| PJM_BAU | 2023 | 0 | 0 | | 2023 | 21,278 | 8,888 | 17,316 | 1,555 |
| PJM_BAU | 2024 | 0 | 0 | | 2024 | 21,653 | 9,237 | 19,397 | 1,555 |
| PJM_BAU | 2025 | 0 | 0 | | 2025 | 22,100 | 9,545 | 20,131 | 1,555 |
| PJM_BAU | 2026 | 0 | 2400 | | 2026 | 23,088 | 9,811 | 20,356 | 1,555 |
| PJM_BAU | 2027 | 0 | 2400 | | 2027 | 23,905 | 10,061 | 20,159 | 1,555 |
| PJM_BAU | 2028 | 0 | 1200 | | 2028 | 24,956 | 10,316 | 19,811 | 1,555 |
| PJM_BAU | 2029 | 0 | 2400 | | 2029 | 25,939 | 10,635 | 19,921 | 1,555 |
| PJM_BAU | 2030 | 0 | 2400 | | 2030 | 27,143 | 10,937 | 19,701 | 1,555 |
| PJM_BAU | 2031 | 0 | 2400 | | 2031 | 28,112 | 11,254 | 19,512 | 1,555 |
| PJM_BAU | 2032 | 0 | 2400 | | 2032 | 29,640 | 11,586 | 19,380 | 1,555 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| PJM_BAU | 2033 | 0 | 2400 | | 2033 | 30,771 | 11,933 | 19,277 | 1,555 |
| PJM_BAU | SUM: | 0 | 20400 | | EXT. | 109,432 | 42,010 | 60,491 | 322 |
| QuadCities | 1_REPORT | | | | **Total (2014 $)** | **$355,238** | **$137,507** | **$245,256** | **$23,403** |
| QuadCities | 1_REPORT | | | | **Annualized** | **$22,787** | **$8,821** | **$15,732** | **$1,501** |
| QuadCities | 2014 | 0 | 0 | | 2014 | 17,646 | 5,309 | 1,085 | - |
| QuadCities | 2015 | 0 | 0 | | 2015 | 18,616 | 5,620 | 3,316 | 1,660 |
| QuadCities | 2016 | 0 | 2400 | | 2016 | 18,177 | 6,510 | 10,534 | 1,560 |
| QuadCities | 2017 | 0 | 0 | | 2017 | 18,637 | 6,981 | 11,989 | 1,555 |
| QuadCities | 2018 | 0 | 0 | | 2018 | 19,088 | 7,450 | 13,176 | 1,555 |
| QuadCities | 2019 | 0 | 0 | | 2019 | 19,708 | 7,701 | 14,251 | 1,555 |
| QuadCities | 2020 | 0 | 0 | | 2020 | 20,315 | 7,994 | 15,453 | 1,555 |
| QuadCities | 2021 | 0 | 0 | | 2021 | 20,531 | 8,279 | 16,553 | 1,555 |
| QuadCities | 2022 | 0 | 0 | | 2022 | 20,899 | 8,560 | 17,325 | 1,555 |
| QuadCities | 2023 | 0 | 1200 | | 2023 | 21,533 | 8,783 | 17,493 | 1,555 |
| QuadCities | 2024 | 0 | 0 | | 2024 | 21,907 | 9,130 | 19,567 | 1,555 |
| QuadCities | 2025 | 0 | 1200 | | 2025 | 22,339 | 9,448 | 20,478 | 1,555 |
| QuadCities | 2026 | 0 | 1200 | | 2026 | 23,351 | 9,698 | 20,498 | 1,555 |
| QuadCities | 2027 | 0 | 2400 | | 2027 | 24,185 | 9,945 | 20,294 | 1,555 |
| QuadCities | 2028 | 0 | 2400 | | 2028 | 25,236 | 10,212 | 20,139 | 1,555 |
| QuadCities | 2029 | 0 | 1200 | | 2029 | 26,236 | 10,514 | 20,032 | 1,555 |
| QuadCities | 2030 | 0 | 2400 | | 2030 | 27,464 | 10,812 | 19,805 | 1,555 |
| QuadCities | 2031 | 0 | 2400 | | 2031 | 28,446 | 11,126 | 19,611 | 1,555 |
| QuadCities | 2032 | 0 | 2400 | | 2032 | 29,997 | 11,455 | 19,474 | 1,555 |
| QuadCities | 2033 | 0 | 2400 | | 2033 | 31,140 | 11,798 | 19,366 | 1,555 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| QuadCities | SUM: | 0 | 21600 | | EXT. | 110,744 | 41,533 | 60,751 | 322 |
| Byron | 2_REPORT | | | | **Total (2014 $)** | **$357,710** | **$136,569** | **$246,341** | **$23,403** |
| Byron | 2_REPORT | | | | **Annualized** | **$22,946** | **$8,760** | **$15,802** | **$1,501** |
| Byron | 2014 | 0 | 0 | | 2014 | 17,646 | 5,309 | 1,085 | - |
| Byron | 2015 | 0 | 0 | | 2015 | 18,616 | 5,620 | 3,316 | 1,660 |
| Byron | 2016 | 0 | 2400 | | 2016 | 18,177 | 6,510 | 10,534 | 1,560 |
| Byron | 2017 | 0 | 0 | | 2017 | 18,637 | 6,981 | 11,989 | 1,555 |
| Byron | 2018 | 0 | 0 | | 2018 | 19,088 | 7,450 | 13,176 | 1,555 |
| Byron | 2019 | 0 | 0 | | 2019 | 19,908 | 7,622 | 14,251 | 1,555 |
| Byron | 2020 | 0 | 0 | | 2020 | 20,505 | 7,913 | 15,453 | 1,555 |
| Byron | 2021 | 0 | 0 | | 2021 | 20,728 | 8,196 | 16,553 | 1,555 |
| Byron | 2022 | 0 | 1200 | | 2022 | 21,097 | 8,487 | 17,497 | 1,555 |
| Byron | 2023 | 0 | 1200 | | 2023 | 21,725 | 8,708 | 17,658 | 1,555 |
| Byron | 2024 | 0 | 0 | | 2024 | 22,102 | 9,053 | 19,724 | 1,555 |
| Byron | 2025 | 0 | 1200 | | 2025 | 22,538 | 9,370 | 20,628 | 1,555 |
| Byron | 2026 | 0 | 1200 | | 2026 | 23,549 | 9,617 | 20,642 | 1,555 |
| Byron | 2027 | 0 | 2400 | | 2027 | 24,398 | 9,863 | 20,431 | 1,555 |
| Byron | 2028 | 0 | 1200 | | 2028 | 25,473 | 10,113 | 20,071 | 1,555 |
| Byron | 2029 | 0 | 2400 | | 2029 | 26,469 | 10,427 | 20,170 | 1,555 |
| Byron | 2030 | 0 | 2400 | | 2030 | 27,729 | 10,724 | 19,938 | 1,555 |
| Byron | 2031 | 0 | 2400 | | 2031 | 28,710 | 11,035 | 19,737 | 1,555 |
| Byron | 2032 | 0 | 2400 | | 2032 | 30,265 | 11,362 | 19,593 | 1,555 |
| Byron | 2033 | 0 | 2400 | | 2033 | 31,444 | 11,703 | 19,478 | 1,555 |
| Byron | SUM: | 0 | 22800 | | EXT. | 111,826 | 41,192 | 61,043 | 322 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| LaSalle | 3_REPORT | | | | **Total (2014 $)** | **$357,434** | **$136,644** | **$246,341** | **$23,403** |
| LaSalle | 3_REPORT | | | | **Annualized** | **$22,928** | **$8,765** | **$15,802** | **$1,501** |
| LaSalle | 2014 | 0 | 0 | | 2014 | 17,646 | 5,309 | 1,085 | - |
| LaSalle | 2015 | 0 | 0 | | 2015 | 18,616 | 5,620 | 3,316 | 1,660 |
| LaSalle | 2016 | 0 | 2400 | | 2016 | 18,177 | 6,510 | 10,534 | 1,560 |
| LaSalle | 2017 | 0 | 0 | | 2017 | 18,637 | 6,981 | 11,989 | 1,555 |
| LaSalle | 2018 | 0 | 0 | | 2018 | 19,088 | 7,450 | 13,176 | 1,555 |
| LaSalle | 2019 | 0 | 0 | | 2019 | 19,890 | 7,628 | 14,251 | 1,555 |
| LaSalle | 2020 | 0 | 0 | | 2020 | 20,489 | 7,918 | 15,453 | 1,555 |
| LaSalle | 2021 | 0 | 0 | | 2021 | 20,689 | 8,202 | 16,553 | 1,555 |
| LaSalle | 2022 | 0 | 1200 | | 2022 | 21,085 | 8,493 | 17,497 | 1,555 |
| LaSalle | 2023 | 0 | 1200 | | 2023 | 21,693 | 8,715 | 17,658 | 1,555 |
| LaSalle | 2024 | 0 | 0 | | 2024 | 22,086 | 9,060 | 19,724 | 1,555 |
| LaSalle | 2025 | 0 | 1200 | | 2025 | 22,499 | 9,376 | 20,628 | 1,555 |
| LaSalle | 2026 | 0 | 1200 | | 2026 | 23,556 | 9,624 | 20,642 | 1,555 |
| LaSalle | 2027 | 0 | 2400 | | 2027 | 24,353 | 9,869 | 20,431 | 1,555 |
| LaSalle | 2028 | 0 | 1200 | | 2028 | 25,458 | 10,120 | 20,071 | 1,555 |
| LaSalle | 2029 | 0 | 2400 | | 2029 | 26,444 | 10,434 | 20,170 | 1,555 |
| LaSalle | 2030 | 0 | 2400 | | 2030 | 27,681 | 10,731 | 19,938 | 1,555 |
| LaSalle | 2031 | 0 | 2400 | | 2031 | 28,695 | 11,043 | 19,737 | 1,555 |
| LaSalle | 2032 | 0 | 2400 | | 2032 | 30,225 | 11,370 | 19,593 | 1,555 |
| LaSalle | 2033 | 0 | 2400 | | 2033 | 31,423 | 11,711 | 19,478 | 1,555 |
| LaSalle | SUM: | 0 | 22800 | | EXT. | 111,751 | 41,221 | 61,043 | 322 |
| Braidwood | 4_REPORT | | | | **Total (2014 $)** | **$357,851** | **$136,529** | **$246,341** | **$23,403** |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Braidwood | 4_REPORT | | | | **Annualized** | **$22,955** | **$8,758** | **$15,802** | **$1,501** |
| Braidwood | 2014 | 0 | 0 | | 2014 | 17,646 | 5,309 | 1,085 | - |
| Braidwood | 2015 | 0 | 0 | | 2015 | 18,616 | 5,620 | 3,316 | 1,660 |
| Braidwood | 2016 | 0 | 2400 | | 2016 | 18,177 | 6,510 | 10,534 | 1,560 |
| Braidwood | 2017 | 0 | 0 | | 2017 | 18,637 | 6,981 | 11,989 | 1,555 |
| Braidwood | 2018 | 0 | 0 | | 2018 | 19,088 | 7,450 | 13,176 | 1,555 |
| Braidwood | 2019 | 0 | 0 | | 2019 | 19,913 | 7,619 | 14,251 | 1,555 |
| Braidwood | 2020 | 0 | 0 | | 2020 | 20,521 | 7,910 | 15,453 | 1,555 |
| Braidwood | 2021 | 0 | 0 | | 2021 | 20,734 | 8,192 | 16,553 | 1,555 |
| Braidwood | 2022 | 0 | 1200 | | 2022 | 21,106 | 8,484 | 17,497 | 1,555 |
| Braidwood | 2023 | 0 | 1200 | | 2023 | 21,742 | 8,705 | 17,658 | 1,555 |
| Braidwood | 2024 | 0 | 0 | | 2024 | 22,111 | 9,050 | 19,724 | 1,555 |
| Braidwood | 2025 | 0 | 1200 | | 2025 | 22,548 | 9,366 | 20,628 | 1,555 |
| Braidwood | 2026 | 0 | 1200 | | 2026 | 23,576 | 9,614 | 20,642 | 1,555 |
| Braidwood | 2027 | 0 | 2400 | | 2027 | 24,407 | 9,859 | 20,431 | 1,555 |
| Braidwood | 2028 | 0 | 1200 | | 2028 | 25,486 | 10,109 | 20,071 | 1,555 |
| Braidwood | 2029 | 0 | 2400 | | 2029 | 26,479 | 10,423 | 20,170 | 1,555 |
| Braidwood | 2030 | 0 | 2400 | | 2030 | 27,737 | 10,720 | 19,938 | 1,555 |
| Braidwood | 2031 | 0 | 2400 | | 2031 | 28,724 | 11,031 | 19,737 | 1,555 |
| Braidwood | 2032 | 0 | 2400 | | 2032 | 30,292 | 11,358 | 19,593 | 1,555 |
| Braidwood | 2033 | 0 | 2400 | | 2033 | 31,454 | 11,699 | 19,478 | 1,555 |
| Braidwood | SUM: | 0 | 22800 | | EXT. | 111,862 | 41,177 | 61,043 | 322 |
| Dresden | 5_REPORT | | | | **Total (2014 $)** | **$356,573** | **$136,968** | **$245,961** | **$23,403** |
| Dresden | 5_REPORT | | | | **Annualized** | **$22,873** | **$8,786** | **$15,778** | **$1,501** |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Dresden | 2014 | 0 | 0 | | 2014 | 17,646 | 5,309 | 1,085 | - |
| Dresden | 2015 | 0 | 0 | | 2015 | 18,616 | 5,620 | 3,316 | 1,660 |
| Dresden | 2016 | 0 | 2400 | | 2016 | 18,177 | 6,510 | 10,534 | 1,560 |
| Dresden | 2017 | 0 | 0 | | 2017 | 18,637 | 6,981 | 11,989 | 1,555 |
| Dresden | 2018 | 0 | 0 | | 2018 | 19,088 | 7,450 | 13,176 | 1,555 |
| Dresden | 2019 | 0 | 0 | | 2019 | 19,811 | 7,656 | 14,251 | 1,555 |
| Dresden | 2020 | 0 | 0 | | 2020 | 20,423 | 7,948 | 15,453 | 1,555 |
| Dresden | 2021 | 0 | 0 | | 2021 | 20,629 | 8,231 | 16,553 | 1,555 |
| Dresden | 2022 | 0 | 0 | | 2022 | 21,006 | 8,511 | 17,325 | 1,555 |
| Dresden | 2023 | 0 | 1200 | | 2023 | 21,649 | 8,733 | 17,493 | 1,555 |
| Dresden | 2024 | 0 | 0 | | 2024 | 21,997 | 9,078 | 19,567 | 1,555 |
| Dresden | 2025 | 0 | 1200 | | 2025 | 22,447 | 9,396 | 20,478 | 1,555 |
| Dresden | 2026 | 0 | 2400 | | 2026 | 23,449 | 9,658 | 20,688 | 1,555 |
| Dresden | 2027 | 0 | 1200 | | 2027 | 24,308 | 9,890 | 20,282 | 1,555 |
| Dresden | 2028 | 0 | 2400 | | 2028 | 25,357 | 10,156 | 20,126 | 1,555 |
| Dresden | 2029 | 0 | 2400 | | 2029 | 26,374 | 10,471 | 20,224 | 1,555 |
| Dresden | 2030 | 0 | 2400 | | 2030 | 27,589 | 10,768 | 19,990 | 1,555 |
| Dresden | 2031 | 0 | 2400 | | 2031 | 28,611 | 11,081 | 19,788 | 1,555 |
| Dresden | 2032 | 0 | 2400 | | 2032 | 30,150 | 11,409 | 19,642 | 1,555 |
| Dresden | 2033 | 0 | 2400 | | 2033 | 31,300 | 11,751 | 19,526 | 1,555 |
| Dresden | SUM: | 0 | 22800 | | EXT. | 111,313 | 41,364 | 61,083 | 322 |
| PJM_HG | ICC_PJM_HG | | | | **Total (2014 $)** | **$371,781** | **$138,797** | **$244,412** | **$23,403** |
| PJM_HG | ICC_PJM_HG | | | | **Annualized** | **$23,849** | **$8,903** | **$15,678** | **$1,501** |
| PJM_HG | 2014 | 0 | 0 | | 2014 | 17,994 | 5,309 | 1,085 | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| PJM_HG | 2015 | 0 | 0 | | 2015 | 19,187 | 5,620 | 3,316 | 1,660 |
| PJM_HG | 2016 | 0 | 2400 | | 2016 | 18,784 | 6,510 | 10,534 | 1,560 |
| PJM_HG | 2017 | 0 | 0 | | 2017 | 19,324 | 6,981 | 11,989 | 1,555 |
| PJM_HG | 2018 | 0 | 0 | | 2018 | 19,839 | 7,450 | 13,176 | 1,555 |
| PJM_HG | 2019 | 0 | 0 | | 2019 | 20,212 | 7,808 | 14,251 | 1,555 |
| PJM_HG | 2020 | 0 | 0 | | 2020 | 20,942 | 8,103 | 15,453 | 1,555 |
| PJM_HG | 2021 | 0 | 0 | | 2021 | 21,150 | 8,391 | 16,553 | 1,555 |
| PJM_HG | 2022 | 0 | 0 | | 2022 | 21,577 | 8,675 | 17,325 | 1,555 |
| PJM_HG | 2023 | 0 | 0 | | 2023 | 22,306 | 8,888 | 17,316 | 1,555 |
| PJM_HG | 2024 | 0 | 0 | | 2024 | 22,693 | 9,237 | 19,397 | 1,555 |
| PJM_HG | 2025 | 0 | 0 | | 2025 | 23,192 | 9,545 | 20,131 | 1,555 |
| PJM_HG | 2026 | 0 | 2400 | | 2026 | 24,398 | 9,811 | 20,356 | 1,555 |
| PJM_HG | 2027 | 0 | 2400 | | 2027 | 25,352 | 10,061 | 20,159 | 1,555 |
| PJM_HG | 2028 | 0 | 1200 | | 2028 | 26,648 | 10,316 | 19,811 | 1,555 |
| PJM_HG | 2029 | 0 | 2400 | | 2029 | 27,874 | 10,635 | 19,921 | 1,555 |
| PJM_HG | 2030 | 0 | 2400 | | 2030 | 29,408 | 10,937 | 19,701 | 1,555 |
| PJM_HG | 2031 | 0 | 2400 | | 2031 | 30,586 | 11,254 | 19,512 | 1,555 |
| PJM_HG | 2032 | 2400 | 0 | | 2032 | 32,550 | 11,591 | 19,623 | 1,555 |
| PJM_HG | 2033 | 2400 | 0 | | 2033 | 33,834 | 11,944 | 19,760 | 1,555 |
| PJM_HG | SUM: | 4800 | 15600 | | EXT. | 127,671 | 42,049 | 61,397 | 322 |
| QuadCities_HG | ICC_PJM_HG_1 | | | | **Total (2014 $)** | **$376,279** | **$137,523** | **$245,934** | **$23,403** |
| QuadCities_HG | ICC_PJM_HG_1 | | | | **Annualized** | **$24,137** | **$8,822** | **$15,776** | **$1,501** |
| QuadCities_HG | 2014 | 0 | 0 | | 2014 | 17,994 | 5,309 | 1,085 | - |
| QuadCities_HG | 2015 | 0 | 0 | | 2015 | 19,187 | 5,620 | 3,316 | 1,660 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| QuadCities_HG | 2016 | 0 | 2400 | | 2016 | 18,784 | 6,510 | 10,534 | 1,560 |
| QuadCities_HG | 2017 | 0 | 0 | | 2017 | 19,324 | 6,981 | 11,989 | 1,555 |
| QuadCities_HG | 2018 | 0 | 0 | | 2018 | 19,839 | 7,450 | 13,176 | 1,555 |
| QuadCities_HG | 2019 | 0 | 0 | | 2019 | 20,537 | 7,701 | 14,251 | 1,555 |
| QuadCities_HG | 2020 | 0 | 0 | | 2020 | 21,282 | 7,994 | 15,453 | 1,555 |
| QuadCities_HG | 2021 | 0 | 0 | | 2021 | 21,501 | 8,279 | 16,553 | 1,555 |
| QuadCities_HG | 2022 | 0 | 0 | | 2022 | 21,917 | 8,560 | 17,325 | 1,555 |
| QuadCities_HG | 2023 | 0 | 1200 | | 2023 | 22,660 | 8,783 | 17,493 | 1,555 |
| QuadCities_HG | 2024 | 0 | 0 | | 2024 | 23,059 | 9,130 | 19,567 | 1,555 |
| QuadCities_HG | 2025 | 0 | 1200 | | 2025 | 23,524 | 9,448 | 20,478 | 1,555 |
| QuadCities_HG | 2026 | 0 | 1200 | | 2026 | 24,776 | 9,698 | 20,498 | 1,555 |
| QuadCities_HG | 2027 | 0 | 2400 | | 2027 | 25,766 | 9,945 | 20,294 | 1,555 |
| QuadCities_HG | 2028 | 0 | 2400 | | 2028 | 27,075 | 10,212 | 20,139 | 1,555 |
| QuadCities_HG | 2029 | 0 | 1200 | | 2029 | 28,329 | 10,514 | 20,032 | 1,555 |
| QuadCities_HG | 2030 | 0 | 2400 | | 2030 | 29,922 | 10,812 | 19,805 | 1,555 |
| QuadCities_HG | 2031 | 1200 | 1200 | | 2031 | 31,062 | 11,129 | 19,729 | 1,555 |
| QuadCities_HG | 2032 | 2400 | 0 | | 2032 | 33,051 | 11,463 | 19,831 | 1,555 |
| QuadCities_HG | 2033 | 2400 | 0 | | 2033 | 34,378 | 11,812 | 19,958 | 1,555 |
| QuadCities_HG | SUM: | 6000 | 15600 | | EXT. | 130,125 | 41,581 | 61,867 | 322 |
| Byron_HG | ICC_PJM_HG_2 | | | | **Total (2014 $)** | **$379,986** | **$136,579** | **$246,799** | **$23,403** |
| Byron_HG | ICC_PJM_HG_2 | | | | **Annualized** | **$24,375** | **$8,761** | **$15,831** | **$1,501** |
| Byron_HG | 2014 | 0 | 0 | | 2014 | 17,994 | 5,309 | 1,085 | - |
| Byron_HG | 2015 | 0 | 0 | | 2015 | 19,187 | 5,620 | 3,316 | 1,660 |
| Byron_HG | 2016 | 0 | 2400 | | 2016 | 18,784 | 6,510 | 10,534 | 1,560 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Byron_HG | 2017 | 0 | 0 | | 2017 | 19,324 | 6,981 | 11,989 | 1,555 |
| Byron_HG | 2018 | 0 | 0 | | 2018 | 19,839 | 7,450 | 13,176 | 1,555 |
| Byron_HG | 2019 | 0 | 0 | | 2019 | 20,800 | 7,622 | 14,251 | 1,555 |
| Byron_HG | 2020 | 0 | 0 | | 2020 | 21,533 | 7,913 | 15,453 | 1,555 |
| Byron_HG | 2021 | 0 | 0 | | 2021 | 21,763 | 8,196 | 16,553 | 1,555 |
| Byron_HG | 2022 | 0 | 1200 | | 2022 | 22,185 | 8,487 | 17,497 | 1,555 |
| Byron_HG | 2023 | 0 | 1200 | | 2023 | 22,926 | 8,708 | 17,658 | 1,555 |
| Byron_HG | 2024 | 0 | 0 | | 2024 | 23,319 | 9,053 | 19,724 | 1,555 |
| Byron_HG | 2025 | 0 | 1200 | | 2025 | 23,796 | 9,370 | 20,628 | 1,555 |
| Byron_HG | 2026 | 0 | 1200 | | 2026 | 25,063 | 9,617 | 20,642 | 1,555 |
| Byron_HG | 2027 | 0 | 2400 | | 2027 | 26,072 | 9,863 | 20,431 | 1,555 |
| Byron_HG | 2028 | 0 | 1200 | | 2028 | 27,426 | 10,113 | 20,071 | 1,555 |
| Byron_HG | 2029 | 0 | 2400 | | 2029 | 28,681 | 10,427 | 20,170 | 1,555 |
| Byron_HG | 2030 | 0 | 2400 | | 2030 | 30,338 | 10,724 | 19,938 | 1,555 |
| Byron_HG | 2031 | 0 | 2400 | | 2031 | 31,549 | 11,035 | 19,737 | 1,555 |
| Byron_HG | 2032 | 2400 | 0 | | 2032 | 33,565 | 11,367 | 19,836 | 1,555 |
| Byron_HG | 2033 | 2400 | 0 | | 2033 | 34,920 | 11,714 | 19,961 | 1,555 |
| Byron_HG | SUM: | 4800 | 18000 | | EXT. | 132,558 | 41,231 | 61,949 | 322 |
| LaSalle_HG | ICC_PJM_HG_3 | | | | **Total (2014 $)** | **$379,635** | **$136,655** | **$246,799** | **$23,403** |
| LaSalle_HG | ICC_PJM_HG_4 | | | | **Annualized** | **$24,352** | **$8,766** | **$15,831** | **$1,501** |
| LaSalle_HG | 2014 | 0 | 0 | | 2014 | 17,994 | 5,309 | 1,085 | - |
| LaSalle_HG | 2015 | 0 | 0 | | 2015 | 19,187 | 5,620 | 3,316 | 1,660 |
| LaSalle_HG | 2016 | 0 | 2400 | | 2016 | 18,784 | 6,510 | 10,534 | 1,560 |
| LaSalle_HG | 2017 | 0 | 0 | | 2017 | 19,324 | 6,981 | 11,989 | 1,555 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| LaSalle_HG | 2018 | 0 | 0 | 2018 | 19,839 | 7,450 | 13,176 | 1,555 |
| LaSalle_HG | 2019 | 0 | 0 | 2019 | 20,778 | 7,628 | 14,251 | 1,555 |
| LaSalle_HG | 2020 | 0 | 0 | 2020 | 21,516 | 7,918 | 15,453 | 1,555 |
| LaSalle_HG | 2021 | 0 | 0 | 2021 | 21,711 | 8,202 | 16,553 | 1,555 |
| LaSalle_HG | 2022 | 0 | 1200 | 2022 | 22,179 | 8,493 | 17,497 | 1,555 |
| LaSalle_HG | 2023 | 0 | 1200 | 2023 | 22,884 | 8,715 | 17,658 | 1,555 |
| LaSalle_HG | 2024 | 0 | 0 | 2024 | 23,302 | 9,060 | 19,724 | 1,555 |
| LaSalle_HG | 2025 | 0 | 1200 | 2025 | 23,747 | 9,376 | 20,628 | 1,555 |
| LaSalle_HG | 2026 | 0 | 1200 | 2026 | 25,075 | 9,624 | 20,642 | 1,555 |
| LaSalle_HG | 2027 | 0 | 2400 | 2027 | 26,011 | 9,869 | 20,431 | 1,555 |
| LaSalle_HG | 2028 | 0 | 1200 | 2028 | 27,406 | 10,120 | 20,071 | 1,555 |
| LaSalle_HG | 2029 | 0 | 2400 | 2029 | 28,645 | 10,434 | 20,170 | 1,555 |
| LaSalle_HG | 2030 | 0 | 2400 | 2030 | 30,276 | 10,731 | 19,938 | 1,555 |
| LaSalle_HG | 2031 | 0 | 2400 | 2031 | 31,527 | 11,043 | 19,737 | 1,555 |
| LaSalle_HG | 2032 | 2400 | 0 | 2032 | 33,500 | 11,375 | 19,836 | 1,555 |
| LaSalle_HG | 2033 | 2400 | 0 | 2033 | 34,902 | 11,722 | 19,961 | 1,555 |
| LaSalle_HG | SUM: | 4800 | 18000 | EXT. | 132,494 | 41,260 | 61,949 | 322 |
| Braidwood_HG | ICC_PJM_HG_4 | | | **Total (2014 $)** | **$380,066** | **$136,544** | **$247,019** | **$23,403** |
| Braidwood_HG | ICC_PJM_HG_5 | | | **Annualized** | **$24,380** | **$8,759** | **$15,846** | **$1,501** |
| Braidwood_HG | 2014 | 0 | 0 | 2014 | 17,994 | 5,309 | 1,085 | - |
| Braidwood_HG | 2015 | 0 | 0 | 2015 | 19,187 | 5,620 | 3,316 | 1,660 |
| Braidwood_HG | 2016 | 0 | 2400 | 2016 | 18,784 | 6,510 | 10,534 | 1,560 |
| Braidwood_HG | 2017 | 0 | 0 | 2017 | 19,324 | 6,981 | 11,989 | 1,555 |
| Braidwood_HG | 2018 | 0 | 0 | 2018 | 19,839 | 7,450 | 13,176 | 1,555 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Braidwood_HG | 2019 | 0 | 0 | | 2019 | 20,805 | 7,619 | 14,251 | 1,555 |
| Braidwood_HG | 2020 | 0 | 0 | | 2020 | 21,557 | 7,910 | 15,453 | 1,555 |
| Braidwood_HG | 2021 | 0 | 0 | | 2021 | 21,768 | 8,192 | 16,553 | 1,555 |
| Braidwood_HG | 2022 | 0 | 1200 | | 2022 | 22,201 | 8,484 | 17,497 | 1,555 |
| Braidwood_HG | 2023 | 0 | 1200 | | 2023 | 22,950 | 8,705 | 17,658 | 1,555 |
| Braidwood_HG | 2024 | 0 | 0 | | 2024 | 23,331 | 9,050 | 19,724 | 1,555 |
| Braidwood_HG | 2025 | 0 | 1200 | | 2025 | 23,820 | 9,366 | 20,628 | 1,555 |
| Braidwood_HG | 2026 | 0 | 1200 | | 2026 | 25,102 | 9,614 | 20,642 | 1,555 |
| Braidwood_HG | 2027 | 0 | 2400 | | 2027 | 26,093 | 9,859 | 20,431 | 1,555 |
| Braidwood_HG | 2028 | 0 | 1200 | | 2028 | 27,449 | 10,109 | 20,071 | 1,555 |
| Braidwood_HG | 2029 | 0 | 2400 | | 2029 | 28,695 | 10,423 | 20,170 | 1,555 |
| Braidwood_HG | 2030 | 0 | 2400 | | 2030 | 30,353 | 10,720 | 19,938 | 1,555 |
| Braidwood_HG | 2031 | 1200 | 1200 | | 2031 | 31,512 | 11,034 | 19,856 | 1,555 |
| Braidwood_HG | 2032 | 2400 | 0 | | 2032 | 33,512 | 11,366 | 19,950 | 1,555 |
| Braidwood_HG | 2033 | 2400 | 0 | | 2033 | 34,872 | 11,712 | 20,071 | 1,555 |
| Braidwood_HG | SUM: | 6000 | 16800 | | EXT. | 132,343 | 41,226 | 62,159 | 322 |
| Dresden_HG | ICC_PJM_HG_5 | | | | **Total (2014 $)** | **$378,183** | **$136,988** | **$246,858** | **$23,403** |
| Dresden_HG | ICC_PJM_HG_6 | | | | **Annualized** | **$24,259** | **$8,787** | **$15,835** | **$1,501** |
| Dresden_HG | 2014 | 0 | 0 | | 2014 | 17,994 | 5,309 | 1,085 | - |
| Dresden_HG | 2015 | 0 | 0 | | 2015 | 19,187 | 5,620 | 3,316 | 1,660 |
| Dresden_HG | 2016 | 0 | 2400 | | 2016 | 18,784 | 6,510 | 10,534 | 1,560 |
| Dresden_HG | 2017 | 0 | 0 | | 2017 | 19,324 | 6,981 | 11,989 | 1,555 |
| Dresden_HG | 2018 | 0 | 0 | | 2018 | 19,839 | 7,450 | 13,176 | 1,555 |
| Dresden_HG | 2019 | 0 | 0 | | 2019 | 20,678 | 7,656 | 14,251 | 1,555 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Dresden_HG | 2020 | 0 | 0 | | 2020 | 21,428 | 7,948 | 15,453 | 1,555 |
| Dresden_HG | 2021 | 0 | 0 | | 2021 | 21,633 | 8,231 | 16,553 | 1,555 |
| Dresden_HG | 2022 | 0 | 0 | | 2022 | 22,067 | 8,511 | 17,325 | 1,555 |
| Dresden_HG | 2023 | 0 | 1200 | | 2023 | 22,825 | 8,733 | 17,493 | 1,555 |
| Dresden_HG | 2024 | 0 | 0 | | 2024 | 23,174 | 9,078 | 19,567 | 1,555 |
| Dresden_HG | 2025 | 0 | 1200 | | 2025 | 23,674 | 9,396 | 20,478 | 1,555 |
| Dresden_HG | 2026 | 0 | 2400 | | 2026 | 24,918 | 9,658 | 20,688 | 1,555 |
| Dresden_HG | 2027 | 0 | 1200 | | 2027 | 25,952 | 9,890 | 20,282 | 1,555 |
| Dresden_HG | 2028 | 0 | 2400 | | 2028 | 27,266 | 10,156 | 20,126 | 1,555 |
| Dresden_HG | 2029 | 0 | 2400 | | 2029 | 28,548 | 10,471 | 20,224 | 1,555 |
| Dresden_HG | 2030 | 0 | 2400 | | 2030 | 30,129 | 10,768 | 19,990 | 1,555 |
| Dresden_HG | 2031 | 2400 | 0 | | 2031 | 31,285 | 11,086 | 20,025 | 1,555 |
| Dresden_HG | 2032 | 2400 | 0 | | 2032 | 33,264 | 11,419 | 20,113 | 1,555 |
| Dresden_HG | 2033 | 2400 | 0 | | 2033 | 34,596 | 11,767 | 20,227 | 1,555 |
| Dresden_HG | SUM: | 7200 | 15600 | | EXT. | 131,147 | 41,422 | 62,409 | 322 |

# Impact of Nuclear Power Plant Closures in Illinois

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## I. SIMULATED SCENARIOS

In 2018, there will be 119 new generating plants (total asset capacity: 34,942MW) added in the Eastern Interconnection. Three new generating plants (two natural gas plants and one wind farm) with a total asset capacity of 660MW are scheduled to be located in Illinois. In order to study the impact of the proposed closures of three nuclear power plants in Illinois, the following scenarios are simulated based on 2018 Planning Data in the Eastern Interconnection of the United States.

- **Scenario 0: Reference scenario**
  - Current EIA forward fuel price projections
  - None of the 119 generation units are added
- **Scenario 1: Simple market scenario**
  - Same as Scenario 0
  - Closure of Byron, Quad Cities, and Clinton nuclear stations is considered
- **Scenario 2: Likely market scenario without nuclear power plant closures**
  - Same as Scenario 0
  - All 119 generation assets are added
- **Scenario 3: Likely market scenario with nuclear power plant closures**
  - Same as Scenario 2
  - Closure of Byron, Quad Cities, and Clinton nuclear stations is considered
- **Scenario 4: Aggressive market scenario**
  - Same as Scenario 3
  - Current EIA forward fuel price projections plus 4% increase in fuel price
  - There is a 3% load growth
  - Any existing plant with a heat rate higher than 14,000 is decommissioned

## II. SIMULATION RESULTS

### *A. Impact on Energy Transactions between Illinois and the Neighboring States in the Eastern Interconnection*

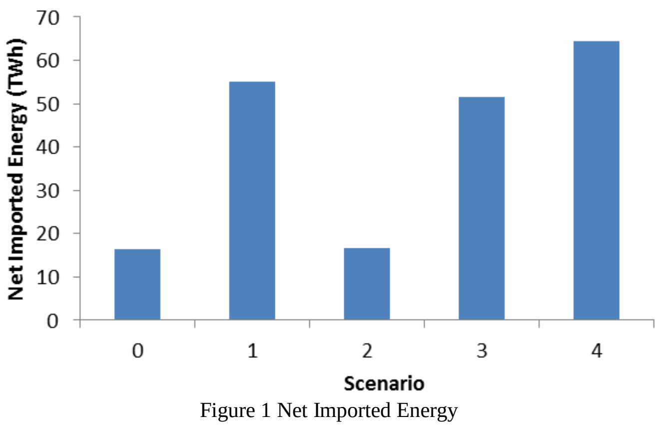


Figure 1 Net Imported Energy

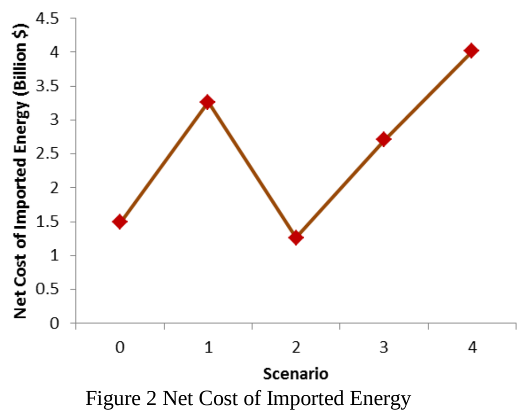


Figure 2 Net Cost of Imported Energy

In all Scenarios shown in Figure 1, Illinois would consistently import energy from its neighboring regions in order to supply its hourly load. However, the closures of nuclear power plants (Scenarios 1, 3 and 4) would result in additional power imports to Illinois. The addition of generation assets in Scenario 2 would decreases the net import as compared with Scenario 1. In Scenarios 4, Illinois would import the highest amount of energy as its load increases, which indicates that there is an insufficient level of generation that is planned in Illinois. Figure 2 shows the annual cost of net import. The cost increase in Scenario 1 when the nuclear units are shut down; the cost drops when additional generation assets are operated in Illinois. The cost increases again when the nuclear units are shut down in Scenario 3. However, the cost in this Scenario is less than that of Scenario 1 because of the addition of generating assets. The cost continues to increase in Scenario 4.

***B. Impact on Transmission Utilization***

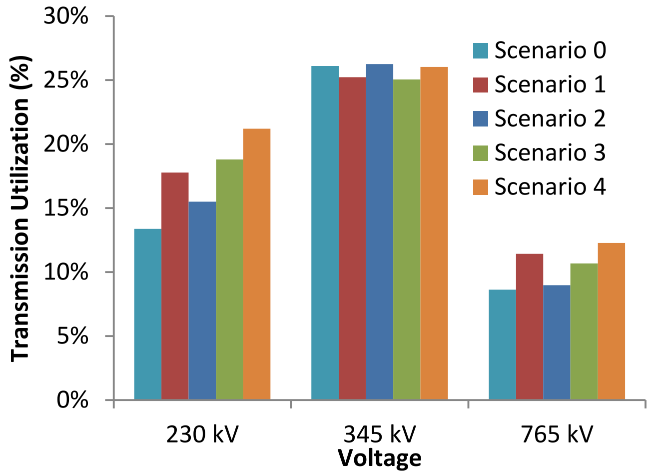



Figure 3 Transmission Utilization Level in Illinois

Figure 3 shows the transmission utilization level in Illinois. Here, the 345kV transmission system shows the highest utilization level in Illinois. The transmission utilization at all voltage levels would increase along with the load growth in Scenario 4. The closure of the three nuclear power plants in Illinois would increase the transmission utilization at 230kV and 765kV levels which shows that the state would mainly depend on 230kV and 765kV transmission system for importing energy. The addition of generating assets in Scenario 2, as compared with that in Scenario 0, would mostly upload the 230 kV lines (i.e., 345 kV and 765 kV lines are less utilized). The closure of nuclear plants in Scenario 3 would again increase the utilization of 230 and 765 kV lines. However, the utilization impact is again more intense on 230kV transmission lines in Illinois.

***C. Impact on LMPs***

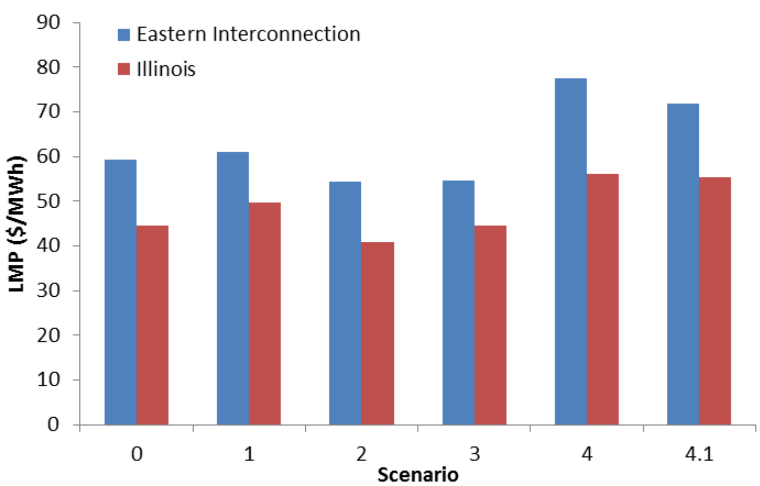
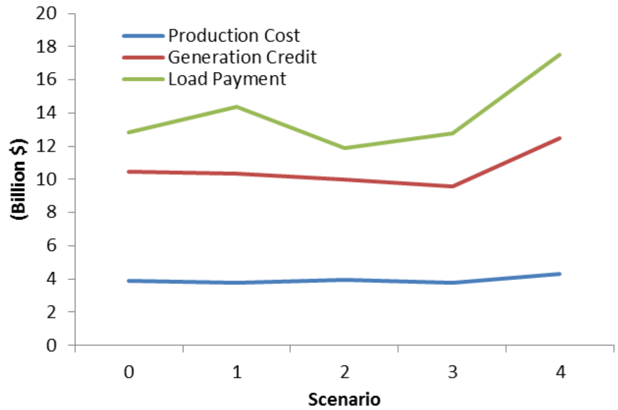


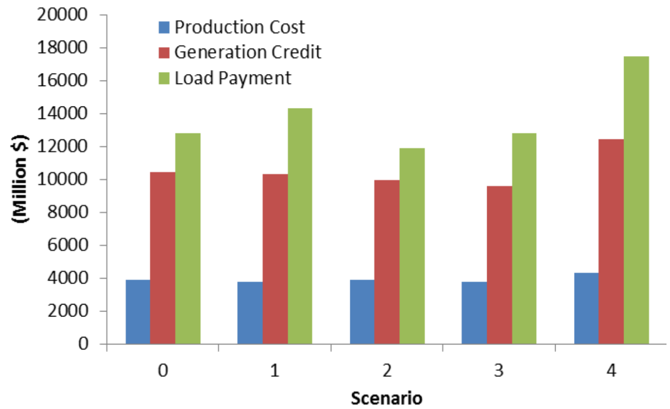

Figure 4 Average Annual LMPs in Illinois

Figure 4 shows the average annual LMPs for both the Eastern Interconnection and Illinois. In Scenario 4.1, we assume the same condition as that in Scenario 4; except, we retain the existing low efficient plants with heat rates that are higher than 14,000. The average annual LMPs in Illinois are lower than those in the Eastern Interconnection (because of cheaper generation in the Midwest) in all six scenarios. The closures of three nuclear power plants in Scenario 1 would result in a $5.28/MWh increase in the average annual LMPs in Illinois as compared with LMPs in Scenario 0 (base case). The additional generation introduced in Scenarios 2 and 3 would reduce the average LMPs. The closure of less efficient units in Scenario 4 would increase the average LMPs. The average annual LMPs would be $0.85/MWh lower in Scenario 4.1 when we retain the less efficient (cheaper) units. The load growth considered in Scenarios 4 and 4.1 would have a large impact on LMPs in the Eastern Interconnection. However, the incremental LMP increase in Illinois is smaller (i.e., red bars are shorter than blue) in Scenarios 4 and 4.1, which indicates that higher levels of congestion exist in other parts of the Eastern interconnection. Compared the LMPs in Scenarios 4 and 4.1, the closure of less efficient would have mirror impact on the LMPs in Illinois (i.e., less than $1/MWh), so we will focus the simulation results of Scenarios 0-4 in the rest of this report.

### D. *Impact on Production Cost, Generation Credit and Load Payment in Illinois*




(a)




(b)

Figure 5 Production Cost, Generation Credit and Load Payment in Illinois

Figure 5 shows the Illinois unit production costs, generation credits and load payments. The production cost is based on the generation unit heat rate and the fuel price. However, generation credit and load payments are based on individual LMPs. The load growth considered in Scenarios 4 would have the largest impact on production cost, generation credit and load payment. The load payments are larger than the generation credits in the five Scenarios since Illinois would import power from its neighboring states.

### E. *Impact on Generation Portfolio in Illinois*

Figure 6 shows the total generation in Illinois would decrease a lot as the three nuclear power plants are closed and more energy are imported from neighboring areas. The proposed closures of the three nuclear power plants would change the generation portfolio in Illinois significantly. Figures 7-11 show that the generation portfolio in Illinois. Here the closure of nuclear plants in Illinois will increase the level of utilization of other types of units in particular the coal units. The additional load in Scenario 4 is picked by the natural gas units.

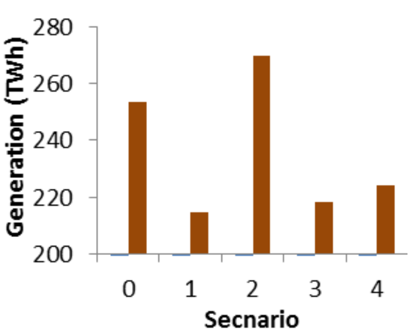



Figure 6 Total Generation in Illinois

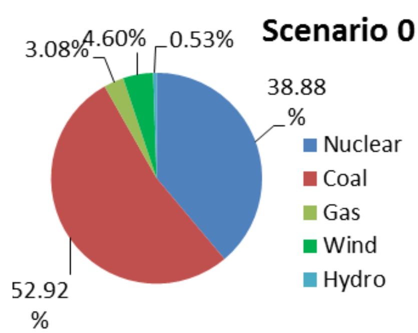



Figure 7 Generation Portfolio in Scenario 0

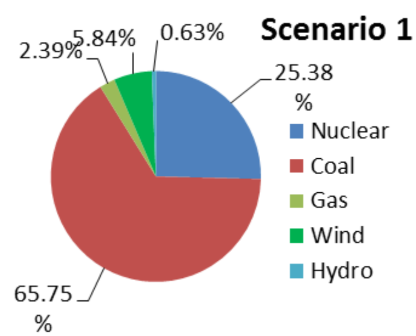



Figure 8 Generation Portfolio in Scenario 1

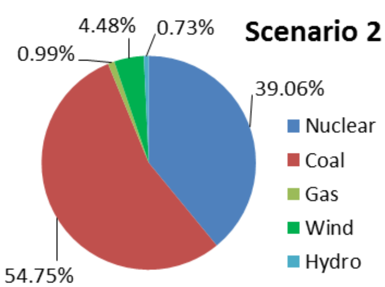



Figure 9 Generation Portfolio in Scenario 2

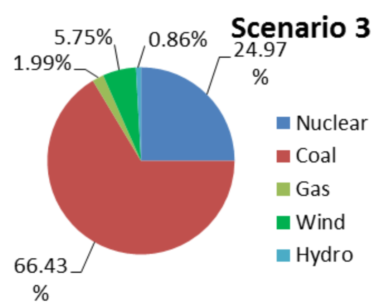



Figure 10 Generation Portfolio in Scenario 3

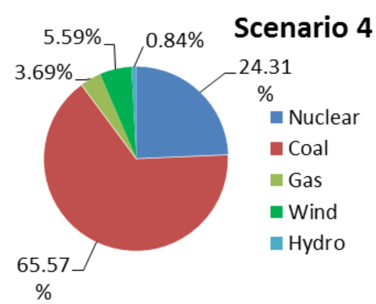



Figure 11 Generation Portfolio in Scenario 4

Monitoring Analytics

# Report for the Illinois Commerce Commission

# Nuclear Plant Retirement Impact Preliminary Analysis of High Load Day

The Independent Market Monitor for PJM

October 30, 2014

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# Introduction

In response to a request from the Illinois Commerce Commission, the Independent Market Monitor for PJM (IMM) evaluated the impact of the potential retirement of two nuclear power stations located in the ComEd zone on PJM markets. This is a preliminary analysis. There would be no impact on the capacity market of the potential retirements because the plants did not clear in the capacity market. The IMM did a near worst case analysis of the energy market which showed that the removal of 4,165 MW of low cost energy would result in higher energy prices, holding everything else constant, on a selected high load day. The study does not calculate the impact on total energy costs for a full year and does not address the impact of the potential retirements on the offer and bid behavior of other market participants. The study also does not address the extent to which the plants would be replaced by new units if they were to retire and the related impact on energy prices.

The two nuclear stations are the Quad Cities Generating Station, with a total installed capacity of 1,819 MW and the Byron Generating Station, with a total installed capacity of 2,346 MW (together referred to as the study plants).

Neither of the plants, owned by Exelon, cleared in the capacity market Base Residual Auction for the 2017/2018 delivery year because the unit offers were greater than the auction clearing price. As a result, there would be no impact on the PJM capacity market if the plants were retired.

To analyze the energy market results, the IMM used the PROBE day ahead market model to produce day ahead market results with and without the study plants. The energy market analysis focused on the effect of the retirements on one day, June 18, 2014. June 18 was picked to illustrate the potential near worst case impact on the energy market on a high load day. On June 15, PJM issued a hot weather alert for the Mid-Atlantic region and Dominion zone for the operating day of June 18. On June 17 at 2035, PJM updated the hot weather alert for June 18 to include the entire RTO.

This report includes the changes to locational marginal prices (LMP) that would result from changes to generation dispatch when the plants are removed from the market for June 18, 2014, holding everything else constant.

# Assumptions

The study uses the PROBE day ahead software to analyze energy market results with and without the study plants. There were no changes to other supply offers or to demand bids in the PJM energy market. This study includes only generation that was available and offered into the day-ahead energy market for June 18. It does not include any generation that was offline due to planned, maintenance or forced outages on June 18. This study does not include any additional generation that is expected to be available in the future. This study does not include any additional demand resources that might be available in the future. The transmission network model used is the network as of June 18 and does not include any scheduled upgrades or changes that were not yet in service.

# Results

## *Price Impact*

The results in this section illustrate the effect of the potential retirements on prices, dispatch MW and load charges for one high load day. The case including the study plants is referred to as the "base case." This is the day-ahead market output from the PROBE engine on June 18 with no changes. The case excluding the study plants is referred to as "with retirements."

Table 1 shows the peak and off peak average zonal LMP for all PJM control zones. On a non-holiday weekday, peak hours are defined as hours ending between 07:00 to 23:00. Table 1 shows that the hourly average zonal LMP increased for all the control zones during both peak and off peak periods. The greatest increase in the hourly average LMPs between the base and with retirement cases were in the ComEd zone. In the ComEd zone the off peak period hourly average price increased by 15.9 percent and the peak period hourly average price increase by 26.6 percent.

**Table 1 Hourly average zonal LMP: peak and off peak before and after the retirements: June 18, 2014**

| Zone | Hourly average LMP Base Case | | Hourly average LMP with Retirements | | Change in hourly average LMP | | Percent change in hourly average LMP | |
|---|---|---|---|---|---|---|---|---|
| | Off peak | Peak | Off peak | Peak | Off peak | Peak | Off peak | Peak |
| AECO | 34.5 | 75.5 | 36.9 | 88.7 | 2.4 | 13.2 | 7.0% | 17.5% |
| AEP | 31.1 | 72.5 | 34.4 | 87.6 | 3.3 | 15.2 | 10.6% | 20.9% |
| APS | 32.3 | 80.7 | 35.1 | 94.2 | 2.8 | 13.5 | 8.7% | 16.7% |
| ATSI | 32.0 | 77.9 | 35.1 | 92.0 | 3.1 | 14.1 | 9.8% | 18.2% |
| BGE | 35.8 | 115.4 | 38.3 | 127.1 | 2.5 | 11.8 | 7.0% | 10.2% |
| COMED | 29.8 | 66.5 | 34.5 | 84.3 | 4.7 | 17.7 | 15.9% | 26.6% |
| DAY | 31.8 | 74.8 | 35.4 | 90.4 | 3.5 | 15.7 | 11.1% | 21.0% |
| DEOK | 30.9 | 80.3 | 34.6 | 94.9 | 3.7 | 14.6 | 12.0% | 18.2% |
| DOM | 34.6 | 96.8 | 37.1 | 109.3 | 2.5 | 12.5 | 7.2% | 12.9% |
| DPL | 34.4 | 95.8 | 36.8 | 108.1 | 2.4 | 12.3 | 6.9% | 12.8% |
| DUQ | 30.7 | 73.6 | 33.7 | 87.3 | 2.9 | 13.8 | 9.6% | 18.7% |
| EKPC | 30.0 | 71.8 | 33.6 | 87.0 | 3.6 | 15.2 | 12.0% | 21.2% |
| JCPL | 34.0 | 74.4 | 36.4 | 87.2 | 2.4 | 12.8 | 7.1% | 17.3% |
| METED | 33.2 | 73.1 | 35.5 | 85.5 | 2.3 | 12.4 | 6.9% | 17.0% |
| PECO | 33.4 | 72.3 | 35.7 | 85.1 | 2.3 | 12.8 | 7.0% | 17.7% |
| PENELEC | 33.1 | 75.2 | 35.8 | 88.4 | 2.7 | 13.2 | 8.0% | 17.5% |
| PEPCO | 35.0 | 106.8 | 37.4 | 118.7 | 2.4 | 11.8 | 6.9% | 11.1% |
| PPL | 32.9 | 70.9 | 35.3 | 83.4 | 2.3 | 12.6 | 7.1% | 17.7% |
| PSEG | 34.4 | 74.1 | 36.8 | 87.2 | 2.4 | 13.1 | 6.9% | 17.6% |
| RECO | 34.5 | 74.6 | 37.0 | 88.1 | 2.5 | 13.5 | 7.2% | 18.1% |

Table 2 shows the total load charges for each hour for the entire PJM territory before and after the retirements. Load charges at any bus are calculated as the LMP in dollars per MWh multiplied by the load in MWh for that hour. The total load charges are calculated as the sum of the load charges for all the load buses (fixed load as well as price sensitive demand) in the system.

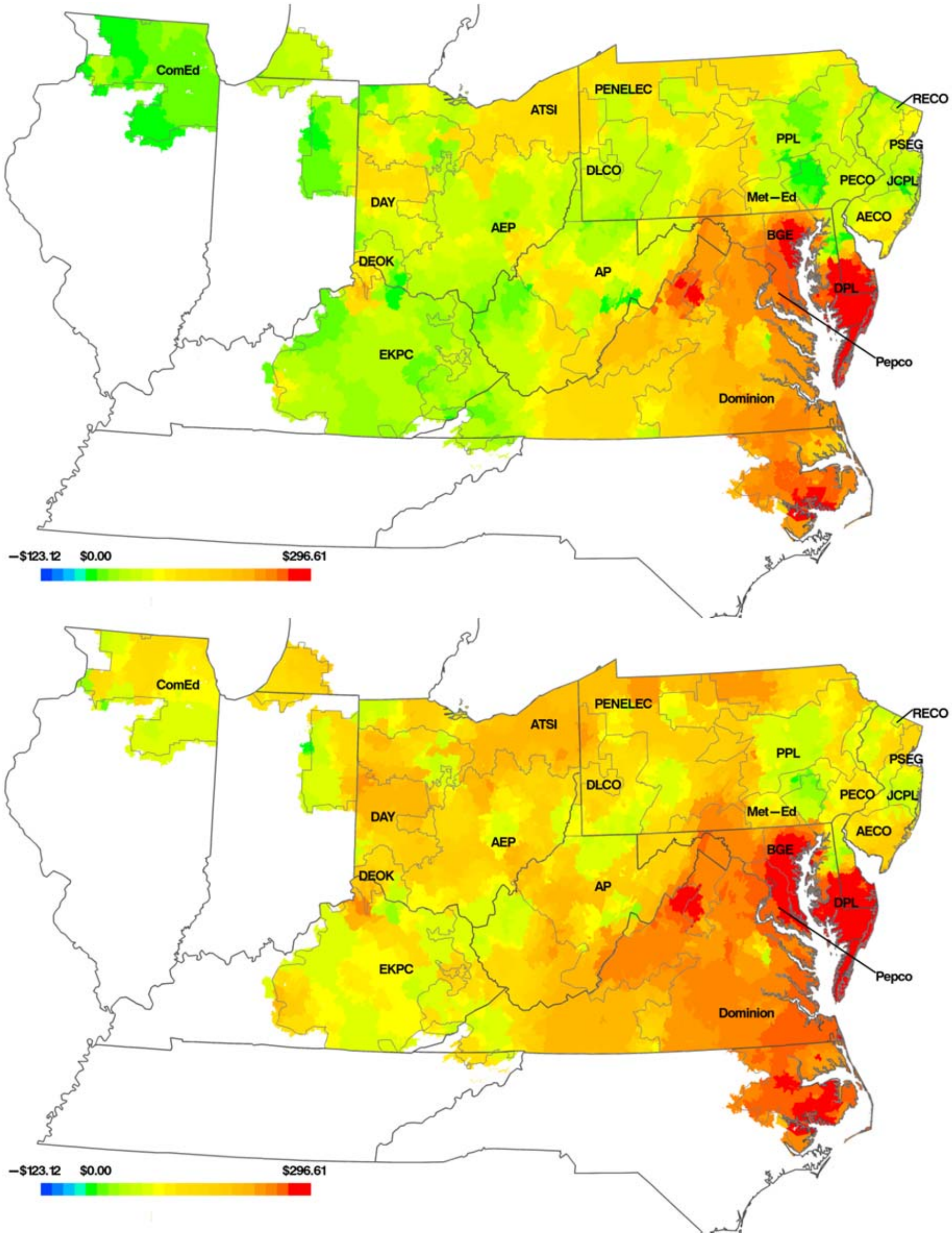
Table 2 shows that for June 18 the total load charges for the system increased by 16.9 percent from $185,674,045 to $217,138,835 between the base and with retirement cases.

**Table 2 Total hourly load charges before and after the retirements: June 18, 2014**

| Hour beginning | Total load charges base case ($) | Total load charges with retirements ($) | Change in charges ($) | Percent change |
|---|---|---|---|---|
| 0:00 | 3,126,215 | 3,484,348 | 358,132 | 11.5% |
| 1:00 | 2,781,131 | 3,121,239 | 340,108 | 12.2% |
| 2:00 | 2,532,497 | 2,675,548 | 143,052 | 5.6% |
| 3:00 | 2,373,220 | 2,462,322 | 89,102 | 3.8% |
| 4:00 | 2,380,636 | 2,453,410 | 72,774 | 3.1% |
| 5:00 | 2,553,217 | 2,712,016 | 158,799 | 6.2% |
| 6:00 | 2,943,251 | 3,239,273 | 296,022 | 10.1% |
| 7:00 | 3,652,423 | 3,952,084 | 299,662 | 8.2% |
| 8:00 | 4,342,157 | 4,673,239 | 331,082 | 7.6% |
| 9:00 | 5,602,796 | 6,434,351 | 831,555 | 14.8% |
| 10:00 | 7,973,512 | 8,131,346 | 157,833 | 2.0% |
| 11:00 | 9,227,990 | 9,798,430 | 570,440 | 6.2% |
| 12:00 | 10,550,374 | 11,667,858 | 1,117,484 | 10.6% |
| 13:00 | 12,546,942 | 14,676,726 | 2,129,783 | 17.0% |
| 14:00 | 14,855,255 | 19,169,626 | 4,314,371 | 29.0% |
| 15:00 | 17,732,070 | 22,962,987 | 5,230,917 | 29.5% |
| 16:00 | 17,506,445 | 23,833,137 | 6,326,692 | 36.1% |
| 17:00 | 14,404,553 | 18,678,928 | 4,274,376 | 29.7% |
| 18:00 | 11,251,120 | 12,648,311 | 1,397,191 | 12.4% |
| 19:00 | 9,847,042 | 10,155,719 | 308,677 | 3.1% |
| 20:00 | 9,208,832 | 10,117,945 | 909,112 | 9.9% |
| 21:00 | 8,418,123 | 8,936,466 | 518,343 | 6.2% |
| 22:00 | 5,742,967 | 6,256,647 | 513,681 | 8.9% |
| 23:00 | 4,121,277 | 4,896,880 | 775,603 | 18.8% |
| Total | 185,674,045 | 217,138,835 | 31,464,790 | 16.9% |

Figure 1 shows the daily average LMP contour map before and after retirements. The contour maps illustrate the geographical variation of LMPs, which is in turn a reflection of congestion in the system. The map in the top portion of Figure 1 shows the daily average LMPs before retirements and the map in the bottom portion shows the daily average LMPs after retirements. The range of LMPs represented by color gradations is from -$123.12 to $296.61.

**Figure 1 Average daily LMP contour map before and after the potential retirements**




# Conclusion

Not surprisingly, removing 4,165 MW of low cost energy from the PJM energy market would result in higher energy market prices, especially when the cost of energy from the efficient combined cycles that would likely replace them is not accounted for. Higher energy market prices would also reduce the capacity market offer caps of remaining units and thus capacity prices, holding everything else equal. The fact that energy market prices would increase does not support providing subsidies to these plants in order to forestall retirement. Any decision to retire the plants would be based on the basic economics of the plants. The basic economics of the plants are a function of capacity market revenue, energy market revenue and going forward costs. A careful, independent review of those economics is necessary before any conclusion could be reached about whether market revenues are adequate to continue to support the operation of the units. The information to do such a review is available to the IMM. The IMM routinely does such analyses as part of the IMM's required retirement review process as well as part of the IMM's review of capacity market offers. Such a review would also have to account for the substantial increase in capacity market revenues that is expected to result from PJM's new capacity market design proposal. If a well structured wholesale power market does not provide enough revenue to support one or both plants, then an appropriate conclusion would be that the clear market signal is to retire one or both plants.

# Illinois Power Agency Appendices

## Appendix A. Capacity Procurement in MISO and PJM

MISO and PJM are each a Regional Transmission Organization (RTO). Each RTO defines a "capacity obligation", which is the tool used to assure resource adequacy. The RTO determines the total capability it will be needed over a given period. In addition, based on detailed performance analyses, each resource in the RTO is assigned an individualized MW value as its capacity credit, or measure of capability. Capacity credits for new or planned resources are projected by the RTO. The RTO holds an auction in which each resource can offer its capability to the RTO, at a price, for the following year or a later year. If a resource is a "winner" of the auction, it is awarded a "capacity obligation." The resource is then obligated to provide its available capacity to the system operator when called upon.

The MISO and PJM capacity auctions are described separately in Sections A.A.1 and A.A.2, respectively. In each case the RTO seeks to award sufficient capacity obligations so that the reserve margin, based on the capacity credits associated with the awarded obligations, will meet or exceed the target margin. One can estimate future reliability based on aspects of the auction results such as the auction clearing prices or the extent to which the supply of capacity credits exceeded the need. As long as the auction clears — that is, as long as the reserve margin target is met — grid resources may be considered adequate.

MISO and PJM allow for load-serving entities to meet their share of the capacity target through self-supply. Several states have attempted to implement capacity procurements within the RTO context. New Jersey and Maryland tried to implement procurement mechanisms under which the purchased capacity would be bid in the PJM RPM auction. An Ohio utility has now requested authorization to sign capacity contracts with an unregulated affiliate; while these would probably also be bid into the RPM, the utility could conceivably use them as the basis for self-supply. These efforts are described in Section A.A.3.

### A.1. MISO Planning Resource Auction

In 2013, MISO implemented a new capacity construct designed to give Load Serving Entities ("LSEs") the flexibility to meet all or a portion of their load requirement through a capacity auction called the Planning Resource Auction ("PRA"). LSEs are required to meet the reserve margin requirements for their zone by participating in a PRA, but may opt-out of the auction by self-scheduling their own resources or submitting a fixed resource adequacy plan.

MISO held its first annual capacity auction in April 2013 for the June 2013-May 2014 planning year. In total, 97,000 MW of capacity cleared the 2013-2014 PRA with all Planning Resource Zones clearing at approximately $1/MW-Day. In the most recent auction in April 2014 for the June 2014-May 2015 planning year, approximately 137,000 MW cleared the auction with

Local Resource Zone[1] 1 ("LRZ") clearing at $3.29/MW-day, LRZs 2-7 (including Ameren Illinois in Zone 4) clearing at $16.75/MW-day, and LRZs 8-9 clearing at $16.44/MW-day.

LSEs that opt out of the PRA meet their capacity obligation through either self-supply by incumbent utilities or through bilateral contracts with capacity resources. Prior to the implementation of PRA, these were the primary means by which LSEs procured capacity. As a result, the market had very limited price transparency for capacity compensation.

MISO performs an "LOLE analysis that calculates the congestion free Planning Reserve Margin ("PRM") requirements."[2] Based on this analysis MISO determines two separate types of reliability metrics.

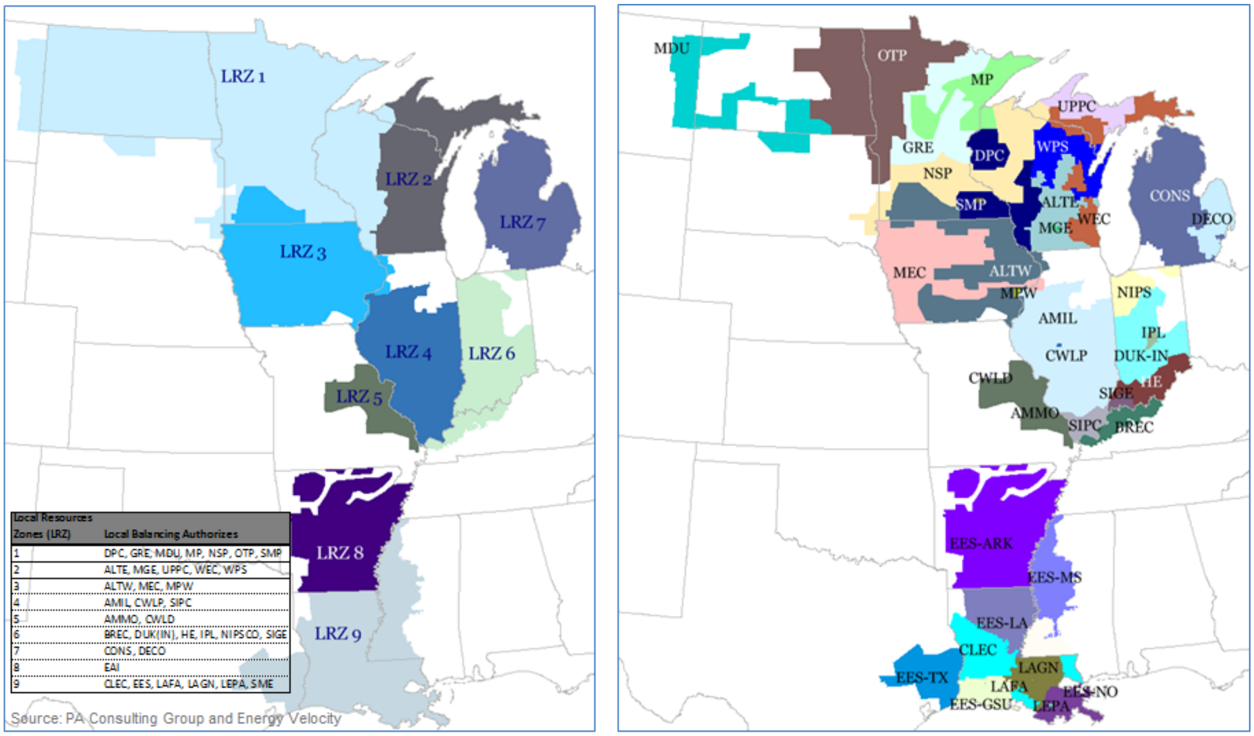
- MISO uses a model of the entire MISO system to estimate LOLE for MISO as a whole. In that exercise, MISO treats the entire system as a single node (that is, MISO does not model any transmission-related limitations within MISO) and assumes a limited amount of support from outside MISO (Capacity Benefit Margin). One may expect that the study will show that the LOLE for the MISO system as a whole is different from 0.1. If the LOLE estimate is less than 0.1, MISO analysts will remove individual plants from the system model until the LOLE reported by the reliability model reaches 0.1. If the LOLE estimate is greater than 0.1, MISO analysts will incorporate enough MW of "perfect capacity"[3] to bring the LOLE down to 0.1. In either case, MISO computes the Planning Reserve Margin target based on the resultant "existing-certain" capability (excluding the plants removed from the model, or including the additional perfect capacity).
- MISO also models each Local Resource Zone (see following map), assuming no internal transmission constraints but also no ability to import power from the rest of MISO or external sources. This will provide a particularly "adverse-case" estimate of reliability, as the original rationale of power pooling was to share reserves to support resource adequacy. As in the first analysis, MISO manipulates the capacity in the model to achieve an LOLE of 0.1 and reports Local Reliability Requirements ("LRRs") that are similar to the Planning Reserve Margin target. Because of the lack of power import, it is possible for several of the zones within MISO to be below their LRRs even if MISO as a whole achieves its Planning Reserve Margin.

[1] LRZ is a geographic area within MISO intended to address congestion that limits the deliverability of resources when considering reliability.

[2] MISO Loss of Load Expectation Working Group ("LOLEWG") Charter, January 16, 2013, at https://www.misoenergy.org/Library/Repository/Meeting Material/Stakeholder/LOLEWG/2013/2013 LOLEWG Charter.pdf.

[3] Perfect capacity means hypothetical capacity that does not suffer planned or unplanned outages and whose capability does not vary across the year but always equals the nameplate value.

**MISO Local Resource Zones (left) and Load Balancing Authorities (right)**




### A.2. PJM Capacity Auction

PJM's capacity market, RPM, was approved by FERC in December 2006 to replace the Capacity Credit Market ("CCM"). RPM is a forward capacity auction with its main capacity auctions, the Base Residual Auction ("BRA"), held each May three years prior to the commitment period. The commitment period is also referred to as a delivery year ("DY") by PJM[4].

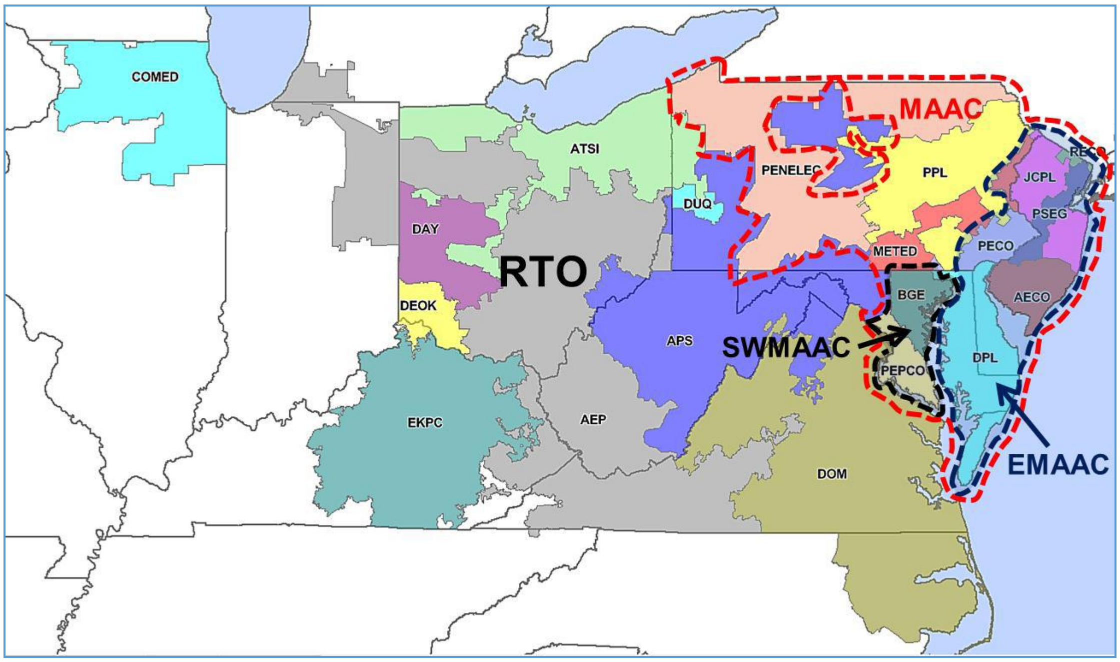
PJM conducts an annual Reserve Requirement Study ("RRS") to determine the IRM, which is the amount of capacity required to reliably serve load in PJM and other key inputs for the PJM RPM capacity auction. The study establishes an IRM that maintains 0.1 LOLE. LSEs that elect not to participate in the RPM auctions can submit a Fixed Resource Requirement ("FRR") Capacity Plan. An LSE submitting an FRR Plan must designate the capacity resources it will utilize to meet its peak demand, plus reserve margin. These capacity resources are not offered into the BRA, and the load served by LSEs submitting FRR Plans does not impact the BRA target; such LSEs have guaranteed their own resource adequacy. The RPM, which covers the bulk of PJM load and provides the incentives for new market-based capacity development, is an indicator of the overall resource adequacy in the RTO.

Each BRA is conducted for some or all of the 27 distinct sub-regions referred to as Locational Deliverability Areas ("LDA"), in addition to the market as a whole, which is referred

[4] A DY is June 1 through May 31 of the following year.

to as the RTO. In addition to the RTO, RPM models distinct supply and demand curves for the Mid-Atlantic Area Council ("MAAC"), Eastern Mid-Atlantic Area Council ("EMAAC") and Southwestern Mid-Atlantic Area Council ("SWMAAC") LDAs, shown in the following map, as well as other LDAs that are close to or short installed capacity to maintain the LDA IRM.

**PJM Locational Deliverability Areas**



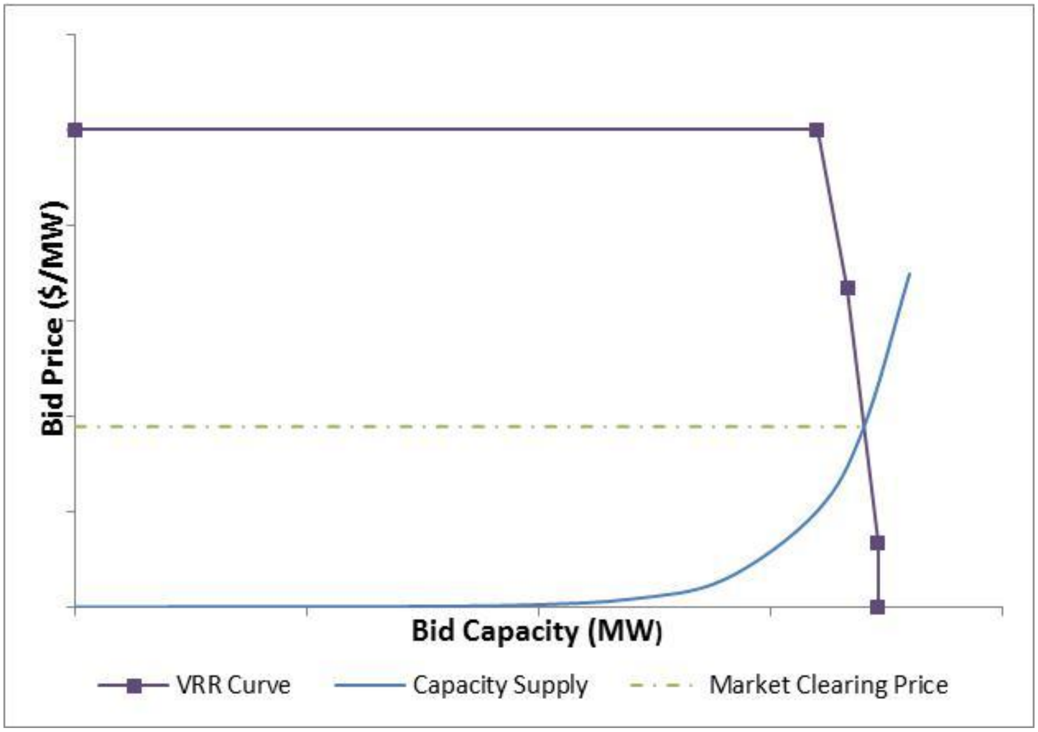

The supply curve is comprised of sell offers from existing capacity resources and new resources looking to enter the market in the BRA. The demand curve, referred to as the Variable Resource Requirement ("VRR") curve, is developed by the PJM ISO prior to the start of each BRA for each of the four zones (RTO, MAAC, EMAAC, and SWMAAC), in addition to other LDAs defined by PJM[5]. Each kink in the VRR curve, as illustrated in below, corresponds to a respective reserve margin and associated capacity price as follows:

- Installed Reserve Margin – 3%;
- Installed Reserve Margin + 1%; and
- Installed Reserve Margin + 5%.

The intersection of the VRR and supply curves determines the capacity price, referred to as the resource clearing price.

[5] The VRR curve is developed based on the LDA's respective target reserve margin and its estimated net cost of new entry, referred to as Net CONE. The Net CONE is based on the capital cost to build a new combustion turbine power generating asset using General Electric Frame 7FA turbines, less expected revenues from the energy and ancillary services markets, including a return on and of the capital.

**Illustrative VRR and Supply Curves**




In the BRA for the 2017/18 DY, which was conducted in May 2014, the individual supply and demand curves for the following lower level LDAs were modeled: PSEG, PSEG-North, DPL-South, Pepco, ATSI, ATSI-Cleveland, ComEd, BG&E and either JCPL or PPL.[6] This means the load and resource balance in these LDAs is approaching the IRM, indicating these LDAs are those where one might expect an LOLE above zero. On the other hand, an LDA with impaired resource adequacy, relative to the RTO as a whole, should have an RPM clearing price that was higher than the RTO-wide clearing price; the only LDA to clear at a higher price was PSEG.

### A.3. State-Specific Capacity Initiatives

Since 2011 both New Jersey and Maryland have attempted to subsidize the development of new generation in their states. By October 2013 the initiatives in both States were ruled illegal by a federal judge. While these efforts were designed to incentivize the construction of new generation, and not keep installed generation in the market, they are presented here to highlight some of the issues that States face when trying to develop initiatives to influence wholesale electricity markets.

[6] "2017/2018 RPM Base Residual Auction Results," PJM document #794597, at http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx, p. 16. The document says "PL" for the last LDA, which is probably a typo and should be either PPL or JCPL.

### a. New Jersey Long-Term Capacity Agreement Pilot Program

New Jersey P.L. 2011, c. 9, known as the Long-Term Capacity Agreement Pilot Program ("LCAPP"), required New Jersey utilities to enter into long-term capacity agreements with generators chosen by the New Jersey Board of Public Utilities ("BPU"). The impetus for the law was the perceived lack of new generation additions in the EMAAC region of PJM that caused New Jersey to question the effectiveness of the PJM market structure. In the 2011 New Jersey Energy Master Plan it was noted that "even though capacity prices in EMAAC have been high, developers have not been willing to add new generation plants in New Jersey without a guarantee of realizing a higher return on investment."[7] The BPU held a technical conference where many participants agreed that the capacity revenues from RPM that were not "stable, secure, and of sufficient term to attract investment in new generation."[8] In response, the New Jersey legislature created LCAPP to "ensure sufficient generation is available to the region, and thus the users in the State, in a timely and orderly manner."

LCAPP established a mechanism for the BPU to authorize the construction of new capacity in the State using a competitive capacity solicitation and required that the four regulated utilities in New Jersey enter into standard offer capacity agreements ("SOCAs") with these generators. The SOCAs were contracts for differences that required the new generators to bid into PJM's RPM and required the New Jersey regulated utilities to pay any difference between the RPM clearing price paid to the new generators and their levelized development costs approved by the BPU and stated in the SOCAs.

PJM market participants mounted a legal challenge to LCAPP in *PPL v. Hanna*. In the case it was argued that LCAPP effectively rendered the price signals from RPM ineffective and impaired the ability to evaluate future costs and revenue streams in the market. New Jersey countered that the contracts were purely financial and, therefore, not subject to FERC oversight. The federal court ruled on behalf of the plaintiffs noting that the:

- SOCAs were more than financial contracts and, as such, infringed on FERC's jurisdiction and right to regulate wholesale electric markets and set rates pursuant to the Federal Power Act; and
- LCAPP impacted the implementation of the FERC approved RPM.

### b. Maryland Capacity Contract for Differences Program

In April 2012, the Maryland Public Service Commission ("MPSC") initiated a program similar to New Jersey's LCAPP to incentivize the construction of new capacity in the State. The program used a competitive capacity solicitation and required the three regulated utilities in the State to enter into a contract for differences with Competitive Power Ventures ("CPV") to cover the cost of developing CPV's natural gas combined cycle selected under the program. The contract for differences contracts were structured to pay CVP any difference between the RPM clearing price the unit received and the levelized cost to construct the generator defined in the order.

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[7] 2011 New Jersey Energy Master Plan, December 6, 2011, pg. 34.

[8] 2011 New Jersey Energy Master Plan, December 6, 2011, pg. 34.

The MPSC order approving CPV's generator under the program cited the concern that RPM has resulted in no new capacity being built in the state.

Incumbent generators in PJM mounted a legal challenge to the program in *PPL v. Nazarian*. In the case it was argued that the program effectively set wholesale rates in interstate commerce. The court agreed with this, noting that the Federal Power Act preempted the program. The U.S. Court of Appeals affirmed the finding of the lower court for the Fourth Circuit on June 2, 2014. In its finding, the appellate court stated that the contracts qualified "as compensation for interstate sales at wholesale, not simply for CPV's construction of a plant."

**c. Ohio Utility Rate Cases**

FirstEnergy ("FE") filed its Ohio rate case in August 2014. The plan commits FE's regulated Ohio distribution utilities, the Illuminating Co., Ohio Edison, and Toledo Edison, to enter into a 15-year contract to buy all of the power that two of their unregulated generation plants produce. The two plants are the 889 MW Davis-Besse nuclear plant and 2,233 W.H. Sammis coal-fired (2,220 MW) and oil-fired (13 MW) facility. W.H. Sammis recently underwent a five-year, $1.8 billion environmental project including the installation of scrubbers and selective catalytic reduction equipment designed to significantly reduce emissions of sulfur dioxide, nitrogen-oxide and mercury.

AEP Ohio is seeking to enter into long-term fixed-price contracts with four of its five unregulated coal generation plants in Ohio. The four plants are Cardinal, Conesville, Stuart, and Zimmer. The Gavin Plant would be the only AEP coal-fired plant in Ohio not part of a long-term contract. AEP has positioned the long-term contracts as necessary to make sure the struggling plants stay open and point to economic and tax impacts they have on the State as well as the financial hedge they would provide.

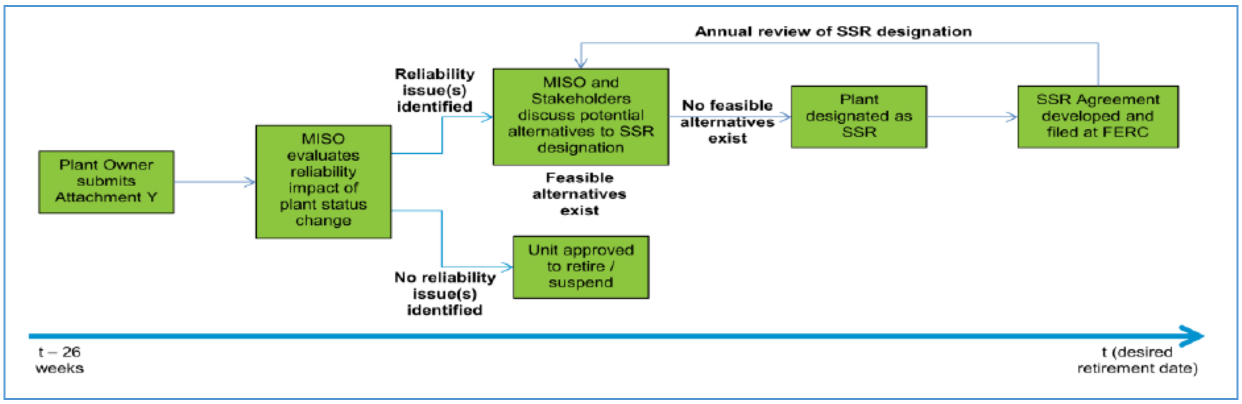
Both FE and AEP would sell the power procured under the long-term contracts into the wholesale electricity market. They are both forecasting the cost of electricity under the contracts will be lower than future market prices. The Public Utilities Commission of Ohio ("PUCO") is reviewing these requests.

# Appendix B. Plant Retirement Procedures

## B.1. MISO System Support Resource Designation

Generation owners in MISO who wish to suspend or retire generation resources have to provide MISO an application (Attachment Y), which communicates their intention to suspend or retire generation, 26 weeks prior to the intended suspend or retirement date. MISO then performs a steady-state reliability analysis to analyze the impact of the suspension or retirement on the transmission system. If there is a material impact on the system, MISO solicits stakeholders for solutions to maintain reliability (e.g. transmission upgrades, new generation, or demand response) and, if none exist, negotiates a System Support Resource ("SSR") Agreement with the generation owner. SSRs receive compensation for their going forward costs resulting from remaining online. Contracts are valid for one year, and can be renewed pending the outcome of an annual reliability analysis. The following flow chart illustrates the Attachment Y process.

**MISO Attachment Y Application Reliability Evaluation**[9]




The following table presents an overview of MISO units with existing SSR Agreements.

[9] Source: MISO System Support Resources unit Retirement Process One Pager.

## Status of Existing SSR Units[10]

| SSR | Start Date | Impacted LBA | Monthly SSR Payment | Status |
|---|---|---|---|---|
| **Edwards Schedule 43C** | 01/01/2013 | AMIL | $750,070 ~~– subject to change per Order ER13-1962, received 7/22/2014~~ | On 11/25/2013, FERC i) accepted Agreement with an effective date of 01/01/2013, ii) accepted cost allocation per Sch. 43C, but iii) FERC action was taken subject to refund and further order (i.e. the ultimate compensation level has not been determined by FERC). |
| **Gaylord Schedule 43D** | 10/01/2013 | CONS | $83,000 | Termination filed on 8/7/2014 in Docket Nos. ER14-2615-000 & ER14-2616-000; Order accepting Sch. 43D termination received 9/30/2014. |
| **Straits Schedule 43E** | 10/01/2013 | CONS | $19,913 every mo. $10,000 first 9 mo. | Termination filed on 8/7/2014 in Docket Nos. ER14-2617-000 & ER14-2618-000; Order accepting Sch. 43E termination received 9/30/2014. |
| **Edwards Schedule 43C (Renewal)** | 01/01/2014 | AMIL | $927,860 – subject to change per Order ER13-1962, received 7/22/2014 | On 3/31/2014, FERC i) accepted Agreement with an effective date of 01/01/2014, ii) accepted cost allocation per Sch. 43C, but iii) FERC action was taken subject to refund and further order. |
| **Presque Isle Schedule 43G** | 02/01/2014 – 10/14/2014 | WEC (93.79%) WPS (0.55%) UPPC (5.66%) | $4,352,832 | Docket Nos. ER14-1242-000, ER12-1243-000 thru 004, EL14-34-000; latest order issued by FERC on 7/29/2014. |
| **White Pines 1 Schedule 43H** | 4/16/2014 | WEC (88%) UPPC (12%) | $264,500.95 $250,000 May-Oct | Docket Nos. ER14-1724-000 & ER14-1725-000; Latest order issued by FERC on 8/21/2014. |
| **Escanaba Schedule 43** | 6/15/2014 | WEC (5.9%) UPPC (94.1%) | $309,190 | Docket Nos. ER14-2176-000 & ER14-2180-000; On 8/12/2014, FERC conditionally accepted the agreement and Sch. 43 and required 30 day compliance. |
| **Presque Isle Schedule 43G (Renewal)** | 10/15/2014 – 12/31/2015 | WEC (93.79%) WPS (0.55%) UPPC (5.66%) | $8,084,500 | Filed on 9/12/2014 in Docket Nos. ER14-2860-000 & ER14-2682-000. |

### B.2. PJM Reliability Must Run Generation

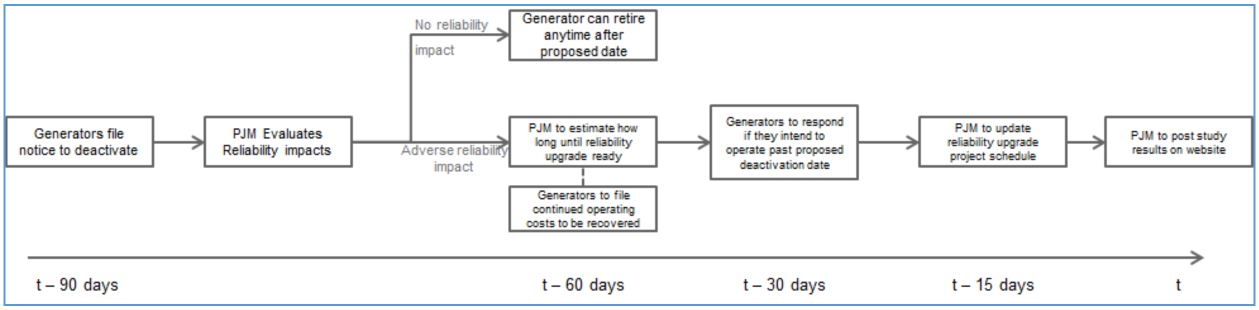
PJM Tariff Part V requires generation owners seeking to deactivate their generator to file notice at least 90 days prior to the proposed deactivation date. Upon receipt of the deactivation notification, PJM has 30 days to evaluate if any reliability criteria would be violated and determine if any reliability upgrades could be completed to address the violation prior to the deactivation date. If the violation cannot be addressed in time, the generator can be designated as a Reliability Must Run ("RMR") generating unit. A flow chart of the PJM deactivation evaluation process is provided below.

RMR generators receive compensation for their going forward costs incurred after the proposed deactivation date and PJM allocates these costs across the LSEs that would have been impacted by the generator's deactivation. PJM's Transmission Expansion Advisory Committee ("TEAC") reviews the status of RMR units at their monthly meetings and once the generator's deactivation no longer violate reliability criteria, the RMR designation is retracted and the generator may retire immediately.

Only Ashtabula 5 is currently designated RMR. East Lake Units 1, 2 & 3 and Lake Shore 18 had their RMR designation removed in September 2014.

[10] Source: MISO MSWG SSR Review, November 7, 2014 - https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/MSWG/2014/20141107/20141107%20MSWG%20Item%2006%20SSR%20Review.pdf.

**PJM Deactivation Request Reliability Evaluation**




## B.3. Nuclear Plant Closures Elsewhere

There are two ways to evaluate the impact of a nuclear plant closure upon capacity and reliability: by analysis and by analogy. The main body of the IPA's response includes the analysis and this section represents the analogy. The Agency considered four recent nuclear plant closures to present both the anticipated impacts on the reliability, and the actions that were taken to mitigate those effects. Mitigations are particularly important in the case of San Onofre because it was not an anticipated retirement.

During the past two years, Wisconsin, California, Vermont, and New York have dealt with the closure of a nuclear power facility. In each case the associated grid operator (respectively MISO, CAISO, ISO-NE and NYISO) evaluated the impact on capacity and reliability of the closure on their grid. The States used the results of those evaluations and their own independent efforts to develop plans to mitigate the impact of plant closures. This section summarizes the process and those plans.

### a. Kewaunee Power Station

The Kewaunee Power Station is located adjacent to Lake Michigan, between Green Bay and Milwaukee, Wisconsin. The 556MW facility is owned and operated by Dominion Resources (Dominion) and licensed to operate until 2033. Kewaunee is a member of MISO and had power purchase agreements (PPA) with Wisconsin Power and Light and Wisconsin Public Services.

In October 2012 Dominion announced the closure of Kewaunee for financial reasons. They were neither able to renew or replace the PPA that expired in 2013 nor improve economies of scale through new construction. They were not able to recover their O&M costs due to low electricity prices in MISO. The facility closed in May 2013.

In February 2013, the Midwest ISO announced that the then pending closure of the Kewaunee Power Station would not affect regional electric system reliability.[11] No mitigation activities are planned.

### b. San Onofre Nuclear Generating Station

The 2,246MW San Onofre Nuclear Generating Station (SONGS) is located on the Pacific Ocean north of San Diego. Jointly owned by Southern California Edison (SCE), San Diego Gas

[11] http://www.elp.com/articles/2013/01/midwest-iso--closing-kewaunee-power-station-will-not-affect-elec.html.

and Electric (SDG&E), and the City of Riverside Utilities, it is operated by SCE and is a member of the CAISO RTO. In addition to its energy production, San Onofre has provided 1,100 MVar of important voltage support to the Los Angeles and San Diego areas.

In 2012, SCE identified significant premature steam turbine tube wear at SONGS. The facility was already under order to significantly reduce its water intake from the Pacific.[12] In June 2013, SCE announced the permanent closure of the facility. Studies conducted by the CAISO indicated no grid wide capacity shortages, although a "multiple contingency shortfall" was identified in the San Diego and Los Angeles areas.

A team consisting of the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and CAISO developed a series of measures to mitigate the loss of SONGS. The CEC forecasts demand for the entire state and licenses new generation. The CPUC approves energy procurement requests for SCE and SDG&E. The CAISO is the grid operator for the subset of California load that includes SCE and SDG&E. Together, the three agencies agreed to[13]:

- Purchase additional capacity in the San Diego and Los Angeles areas.
- Increase transmission capacity to accommodate the import of additional renewable energy.
- Convert a retired power plant to synchronized condensers to provide additional Var support.
- Construct a new transmission line and a phase shifting transformer.

The CEC is monitoring the progress of the above listed projects and has developed contingency plans in case the projects fail to be completed as scheduled or if demand growth is greater than forecast.[14]

### c. Vermont Yankee Nuclear Power Plant

Located on the Connecticut River in the southeast tip of Vermont, the Vermont Yankee Nuclear Power Plant is owned and operated by Entergy. This 629 MW power plant is a member of the ISO-NE RTO. Its NRC license to operate was renewed and expires in 2032. In 2012, Entergy filed with the State of Vermont for approval to continue operation beyond 2012.

In November 2012 ISO-NE determined that Vermont Yankee was not needed for the 2014-2015 commitment period[15]. The plant's PPA with Virginia Electric Power Company and Green Mountain expired in 2012. Lower natural gas prices resulted in a wholesale energy prices

12 In 2010 the California State Water Resources Control Board (SWRCB) had mandated that 12 facilities, including SONGS, utilizing once through cooling (OTC) reduce their water intake by 93%.

13http://www.energy.ca.gov/2014_energypolicy/documents/2014-08-0_workshop/presentations/06_Pettingill_CalISO_8-20-14.pdf.

14 http://www.energy.ca.gov/2014_energypolicy/documents/2014-08-20_workshop/presentations/09_Jaske_CEC_8-20-14.pdf.

15 15ISO-New England, 2013 Regional System Plan, http://www.iso-ne.com/static-assets/documents/trans/rsp/2013/rsp13_final.docxpage 97.

falling 23% in 2012[16]. Entergy announced the facility will close in late 2014 due to financial issues.

ISO-NE has determined that closure will not impact reliability during normal operations.[17] Capacity requirement violations will occur in the event of multiple contingencies in New Hampshire and Massachusetts[18]. The ISO-NE issued a statement that "Regardless of the outcome of these studies, the ISO does not have the authority to prevent a resource from retiring."[19]

The Vermont Department of Public Service identified several alternatives to Vermont Yankee[20] listed below:

- Installation of new combined cycle generation
- Installation of renewable generation
- Increase power imports from Hydro Quebec, NYISO and NEPOOL.

### d. Indian Point Energy Center

Indian Point Energy Center is located on the Hudson River in southeastern New York. Owned and operated by Entergy Nuclear Northeast, the 2,045MW facility is part of the NYISO RTO and holds power purchase agreements with Consolidated Edison and the New York Power Authority. Entergy filed for a 20-year extension on its NRC operating license and can continue to run until NRC issues a decision.

Indian Point is required to obtain a water use permit from the New York Department of Environmental Conservation (NYDEC) to reduce wild life entrainment. The NYDEC favors cooling towers and Entergy prefers intake mesh screens. The NYDEC estimates the cost of installing two sets of cooling towers at about $1 billion. Hearings and an Administrative Law Judge determination process are ongoing. The NYISO expects a decision in 2016 at the earliest. If the Administration Law Judge finds in favor of the NYDEC, Entergy will be required to install the cooling towers or shutdown.[21]

In September 2014, the NYISO published the 2014 Reliability Needs Assessment. The report includes an assessment of the retirement Indian Point[22]. If Indian Point retires in 2016, significant violations of transmission security and resource adequacy criteria will occur.

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16 http://www.iso-ne.com/nwsiss/pr/2013/iso_new_england_issues_statement_vy_retirement_final.pdf.

17 http://www.iso-ne.com/system-planning/system-plans-studies/rsp, page 147.

18 http://www.iso-ne.com/system-planning/system-plans-studies/rsp, page 147.

19 http://www.iso-ne.com/nwsiss/pr/2013/iso_new_england_issues_statement_vy_retirement_final.pdf.

20 http://psb.vermont.gov/sites/psb/files/docket/7440VT_Yankee_Relicensing/DPSact160/Exhibit_2_Alternatives_Report.pdf.

21 See online.wsj.com/articles/new-york-state-indian-point-nuclear-plant-operator-clash-over-fate-of-fish-1410918098; and www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Reliability_Planning_Studies/Reliability_Assessment_Documents/2014%20RNA_final_09162014.pdf, page 53.

22 ibid. page 39.

However, beginning in 2017, there will be insufficient resources to meet operating reserve requirements.

In November 2012 the New York Public Service Commission opened a proceeding with respect to an Indian Point contingency plan. ConEdison and NYPA's Feb 1, 2013 compliance filling[23] included the following mitigation options:

- RFP for additional generation and transmissions resources.
- Develop new transmission projects.
- Develop backstop consisting of energy efficiency, demand response, transmission upgrades, and new RFPs for new generation and transmission facilities.

[23] http://www.nypa.gov/IP/LAW1-346789-v1-IP_Contingency_Plan_Redacted.pdf.

## Appendix C. Base Case GE-MARS Modeling Assumptions

Modeling assumptions common to each case are derived from forecasts and information developed by MISO, PJM, commercially available Ventyx[24] data and GE. The primary input assumptions used by GE-MARS to develop the reliability measure include peak hour load and annual energy, demand response, installed capacity, transmission transfer capabilities between zones in MISO and PJM, and unit forced outage rates. The sources for these and methodology used to develop them for the Base Case and the way GE-MARS uses these are discussed in more detail below.

### C.1. Peak Hour Load and Annual Energy

The non-coincident peak hour load and annual energy forecasts for MISO LBAs and PJM transmission zones are shown in the following tables. The peak hour load and annual energy forecasts for 2018 were utilized to develop the hourly load forecasts for June 1, 2018 to December 31, 2018 and the peak hour load and annual energy forecasts for 2019 were utilized to develop the hourly load forecasts for January 1, 2019 to May 31, 2019.

Load forecasts in both MISO and PJM are inclusive of energy efficiency measures.

[24] Ventyx is the largest provider of commercially available US electricity generator information including existing generator operating statistics, generator retirement information, and proposed new generator information.

## MISO Peak Hour Load and Annual Energy Forecast

| LBA | 2018 | | | 2019 | |
|---|---|---|---|---|---|
| | Peak Hour Load (MW) | Annual Energy (GWh) | | Peak Hour Load (MW) | Annual Energy (GWh) |
| ALTE | 2,777 | 13,533 | | 2,791 | 13,649 |
| ALTW | 3,955 | 21,435 | | 3,976 | 21,548 |
| AMIL | 10,223 | 52,593 | | 10,278 | 52,795 |
| AMMO | 9,299 | 48,217 | | 9,349 | 48,153 |
| BREC | 1,668 | 11,686 | | 1,678 | 11,715 |
| CONS | 9,757 | 43,626 | | 9,809 | 44,264 |
| CWLD | 319 | 1,474 | | 321 | 1,485 |
| CWLP | 462 | 2,044 | | 464 | 2,042 |
| DECO | 12,273 | 60,085 | | 12,339 | 60,859 |
| DPC | 968 | 5,573 | | 973 | 5,479 |
| DUK-IN | 7,596 | 39,016 | | 7,636 | 39,106 |
| GRE | 2,483 | 13,727 | | 2,496 | 13,543 |
| HE | 781 | 3,917 | | 785 | 3,873 |
| IPL | 3,301 | 17,110 | | 3,319 | 17,029 |
| MDU | 547 | 2,989 | | 549 | 2,954 |
| MEC | 5,007 | 24,699 | | 5,033 | 24,787 |
| MGE | 800 | 3,563 | | 803 | 3,595 |
| MP | 1,641 | 10,879 | | 1,649 | 10,967 |
| MPW | 127 | 767 | | 127 | 777 |
| NIPS | 3,672 | 20,893 | | 3,691 | 21,122 |
| NSP | 10,476 | 56,688 | | 10,532 | 57,016 |
| OTP | 2,651 | 14,646 | | 2,665 | 14,302 |
| SIGE | 1,526 | 7,889 | | 1,535 | 7,994 |
| SIPC | 319 | 1,684 | | 321 | 1,664 |
| SMP | 421 | 1,805 | | 423 | 1,814 |
| UPPC | 211 | 1,194 | | 212 | 1,201 |
| WEC | 7,488 | 36,539 | | 7,529 | 36,922 |
| WPS | 2,692 | 13,086 | | 2,707 | 13,375 |
| CLEC | 2,226 | 11,326 | | 2,245 | 11,428 |
| EES-ARK | 7,151 | 39,051 | | 7,213 | 39,402 |
| EES-GSU | 4,374 | 23,927 | | 4,412 | 24,142 |
| EES-LA | 5,906 | 32,757 | | 5,958 | 33,052 |
| EES-MS | 3,571 | 19,535 | | 3,603 | 19,711 |
| EES-NO | 882 | 4,826 | | 890 | 4,870 |
| EES-TX | 3,395 | 18,572 | | 3,425 | 18,740 |
| LAFA | 492 | 2,205 | | 497 | 2,225 |
| LAGN | 2,312 | 10,040 | | 2,332 | 10,131 |
| LEPA | 241 | 1,074 | | 243 | 1,084 |
| SMEPA | 1,462 | 7,211 | | 1,475 | 7,276 |

**PJM Peak Hour Load and Annual Energy Forecast**

| Transmission Zone | 2018 | | | 2019 | |
|---|---|---|---|---|---|
| | Peak Hour Load (MW) | Annual Energy (GWh) | | Peak Hour Load (MW) | Annual Energy (GWh) |
| AECO | 2,876 | 11,799 | | 2,890 | 11,840 |
| AEP | 24,385 | 142,364 | | 24,536 | 142,834 |
| APS | 9,272 | 53,484 | | 9,345 | 53,804 |
| BGE | 7,508 | 36,913 | | 7,595 | 37,049 |
| COMED | 24,198 | 115,388 | | 24,430 | 116,424 |
| DAY | 3,665 | 19,356 | | 3,698 | 19,484 |
| DOM | 22,136 | 109,728 | | 22,481 | 111,347 |
| DPL | 4,360 | 20,453 | | 4,399 | 20,576 |
| DUK-KY | 957 | 4,830 | | 966 | 4,853 |
| DUK-OH | 4,846 | 24,454 | | 4,891 | 24,554 |
| DUQ | 3,133 | 16,107 | | 3,152 | 16,191 |
| EKPC | 1,966 | 10,449 | | 1,977 | 10,466 |
| FE-ATSI | 13,568 | 72,598 | | 13,623 | 72,681 |
| JCPL | 6,644 | 25,967 | | 6,714 | 26,117 |
| METED | 3,210 | 17,714 | | 3,248 | 17,881 |
| PECO | 9,306 | 45,714 | | 9,397 | 46,137 |
| PENELEC | 3,191 | 21,207 | | 3,234 | 21,488 |
| PEPCO | 6,937 | 33,857 | | 6,986 | 34,019 |
| PPL | 7,652 | 45,064 | | 7,733 | 45,380 |
| PSEG | 10,898 | 48,869 | | 10,957 | 49,015 |
| RECO | 432 | 1,599 | | 433 | 1,604 |
| UGI | 208 | 1,154 | | 210 | 1,163 |

The MISO non-coincident peak hour load and annual energy were developed by GE using a multi-stage approach that is explained in detail in Appendix I. The forecast for PJM utilizes non-coincident peak hour and annual energy data for each PJM transmission zone provided in PJM's 2014 Load Forecast Report[25].

Non-coincident peak hour load represents the highest hourly load forecasted to occur in each LBA and transmission zone. The highest peak loads in the different LBAs and transmission zones will not necessarily occur in the same hour in the year. GE-MARS utilizes the non-coincident peak load and annual energy forecasts for each MISO LBA and PJM transmission zone to scale hourly load profiles for each area. The hour in which the RTO peak load occurs is referred to as the coincident peak hour load.

Hourly load profiles for 2005 are used for all but LRZ 8 and 9 in MISO, which use 2006 load profiles because those regions were impacted by Hurricane Katrina in 2005, and are used

[25] Source: http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx.

for each transmission zone in PJM. The source of the historical hourly loads is the Ventyx "Historical Demand by Zone, Hourly" dataset.

### C.2. Demand Response

Demand response is comprised of resources that can reduce demand during emergencies, such as interruptible load and direct control load management, and counts as capacity that can be used to maintain reliability in both MISO and PJM. Demand response resources are accounted for when the RTOs conduct their analyses to determining the reserve margin that is required to meet the 0.1 LOLE. As such, GE-MARS considers demand response resources (along with installed capacity) when determining if each LBA in MISO and transmission zone in PJM has sufficient capacity to meet hourly load and, ultimately, the hourly RTO-wide and zonal LOLEs. The MISO and PJM zonal and total demand response forecasts utilized in this analysis are included in the following tables. All four cases include 14,402 MW of demand response in PJM, and 4,743 MW of demand response in MISO. Case 3 assumes that demand response is not available during the week in which the polar vortex occurs.

The demand response forecasts for MISO and PJM come from the NERC 2014 Summer Reliability Assessment[26] and PJM 2014 Load Forecast Report[27], respectively. The MISO demand response resource forecast was provided for the MISO footprint, while the PJM forecast was provided for each transmission zone.

[26] Source: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014SRA.pdf.

[27] Source: http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx.

**MISO Demand Response Forecast**[28]

| LBA | Demand Response (MW) |
|---|---|
| ALTE | 127 |
| ALTW | 181 |
| AMIL | 469 |
| AMMO | 426 |
| BREC | 76 |
| CONS | 447 |
| CWLD | 15 |
| CWLP | 21 |
| DECO | 563 |
| DPC | 44 |
| DUK-IN | 348 |
| GRE | 114 |
| HE | 36 |
| IPL | 151 |
| MDU | 25 |
| MEC | 230 |
| MGE | 37 |
| MP | 75 |
| MPW | 6 |
| NIPS | 168 |
| NSP | 480 |
| OTP | 122 |
| SIGE | 70 |
| SIPC | 15 |
| SMP | 19 |
| UPPC | 10 |
| WEC | 343 |
| WPS | 123 |
| CLEC | 0 |
| EES-ARK | 0 |
| EES-GSU | 0 |
| EES-LA | 0 |
| EES-MS | 0 |
| EES-NO | 0 |
| EES-TX | 0 |
| LAFA | 0 |
| LAGN | 0 |
| LEPA | 0 |
| SMEPA | 0 |
| **Total** | 4,743 |

**PJM Demand Response Forecast**

| Transmission Zone | Demand Response (MW) |
|---|---|
| AECO | 166 |
| AEP | 1,762 |
| APS | 658 |
| BGE | 900 |
| COMED | 1,187 |
| DAY | 237 |
| DOM | 1,077 |
| DPL | 422 |
| DUK-KY | 55 |
| DUK-OH | 280 |
| DUQ | 137 |
| EKPC | 128 |
| FE-ATSI | 1,740 |
| JCPL | 214 |
| METED | 301 |
| PECO | 510 |
| PENELEC | 415 |
| PEPCO | 638 |
| PPL | 959 |
| PSEG | 606 |
| RECO | 10 |
| UGI | 0 |
| **Total** | 12,402 |

[28] Multiple demand response forecasts exist for MISO, including a higher forecast of 5,427 MW included in the MISO 2014 Summer Resource Assessment. The smaller figure of 4,734 MW from the NERC 2014 Summer Reliability Assessment was used but was spread over the MISO classic footprint, which includes all LRZs except LRZs 8 & 9.

### C.3. Installed Capacity

Installed capacity in MISO and PJM is based on commercially available information from Ventyx and a review of information in the public domain. This is not the same data used by MISO and PJM for their LOLE analysis. The NERC ES&D database is the "official" basis for installed capacity for reliability assessments, but only summary data is publicly available. The public NERC ES&D no longer includes individual unit data (i.e. the Schedule 2 data) because of confidentiality issues for some units.

Installed capacity as of June 1, 2014 in MISO and PJM is derived from the Ventyx database and a capacity expansion plan is developed to account for new installations and retirements between June 1, 2014 and June 1, 2018 based on information from Ventyx, GE's proprietary RECAST (REnewables forCAST) model and a review of publicly available information. Units from the Non-Proprietary Ventyx New Installations database that have a status of "Operating", "Under Construction", "Site Prep", or "Testing" are reviewed for inclusion in the model and modifications are made to reflect announcements from the generation owners or market operators.

- In PJM, capacity that has cleared the RPM BRAs through 2017/18 in excess of that identified for inclusion in GE-MARS based on the aforementioned methodology is identified and added to the model. PJM does not release specific details (such as the location and size) about the units that clear RPM; the information they release is aggregated to show the total amount of new capacity that has cleared in the RTO by technology. Therefore, the capacity that has cleared RPM in excess of that already included in the capacity expansion plan is added to the PJM transmission zones in the model on a load-weighted basis.

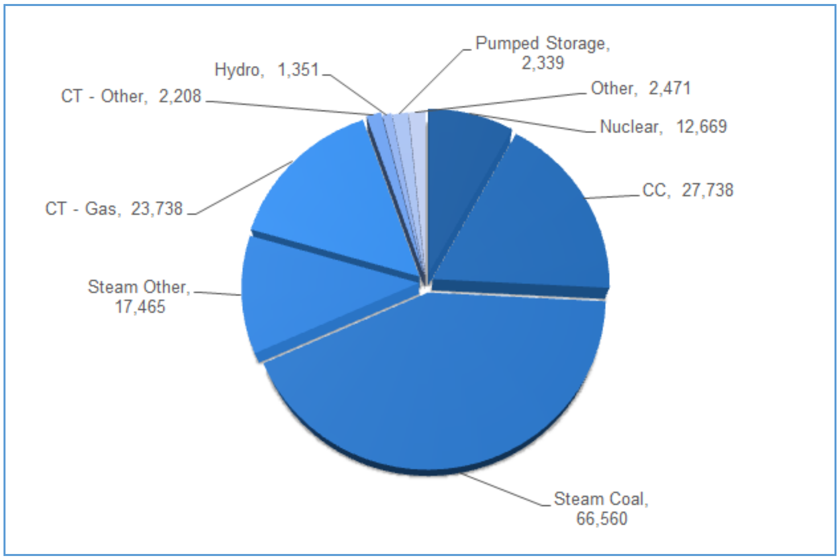
- In MISO, renewable capacity is added to GE-MARS to meet the forecasted requirements developed using the RECAST model. RECAST is designed to take assumptions about current and future state and federal RPS and combines these with existing renewable generation in the system and new generation additions identified in the Non-Proprietary Ventyx New Installations database to develop a renewable capacity expansion plan[29].

The retirement assumptions for all generating units are based upon the Ventyx Velocity Suite database, specifically the "Retirement Date" and "Proposed Retirement Date" records, and a review of publicly available information.

[29] Knowing the capacity required to meet the renewable production standards, the next question RECAST solves is how the targets will likely be reached. RECAST does this through a profit maximization algorithm. This mimics how investors would respond to incentives provided by the government's renewable energy certificates as well as marketplace conditions. A number of technology types are available with different costs and efficiencies that the model uses to meet the targets in the most profitable way. State wholesale and retail level prices are also taken into account. Expectations of the energy from wind, solar, and hydro resources for a given state are also used. In addition, the costs of financing different types of technologies, whether states can import energy to meet the requirements, the forecasted demand for electricity, and limits on the transmission system are all components of the profit maximization.

In MISO in the 2018 - 2019 delivery year, the modeled summer capacity for non-intermittent generation totals 156,540 MW, and wind and solar nameplate capacity totals 15,240 MW.

**MISO Non-Intermittent Summer Installed Capacity (MW)**

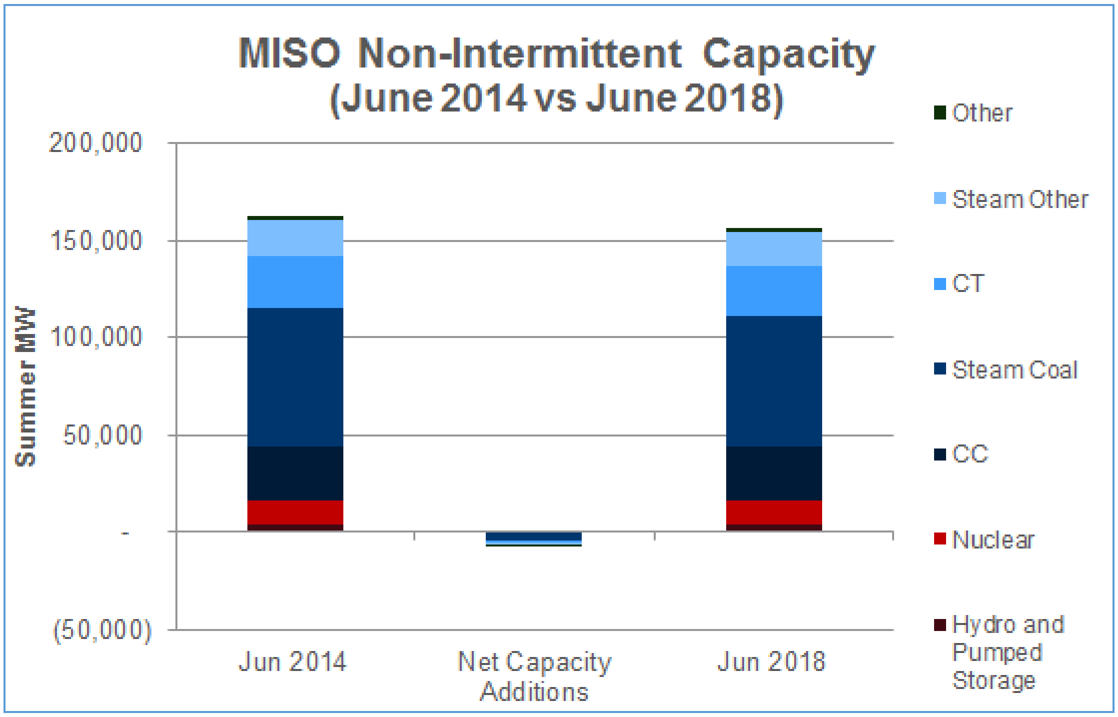



The 156,540 MW of non-intermittent modeled summer capacity installed in MISO in 2018/19 is 5,973 MW lower than the summer installed capacity as of June 1, 2014. The change in summer capacity is driven by a net decrease in:

- Steam coal (-4,784 MW),
- Non-coal steam (-956 MW),
- Combustion turbine (-240 MW), and
- Other generation (-22 MW)

These net retirements are also offset by a slight net increase in hydro generation totaling 29 MW.

**Changes in MISO Non-Intermittent Summer Installed Capacity from 2014 to 2018**



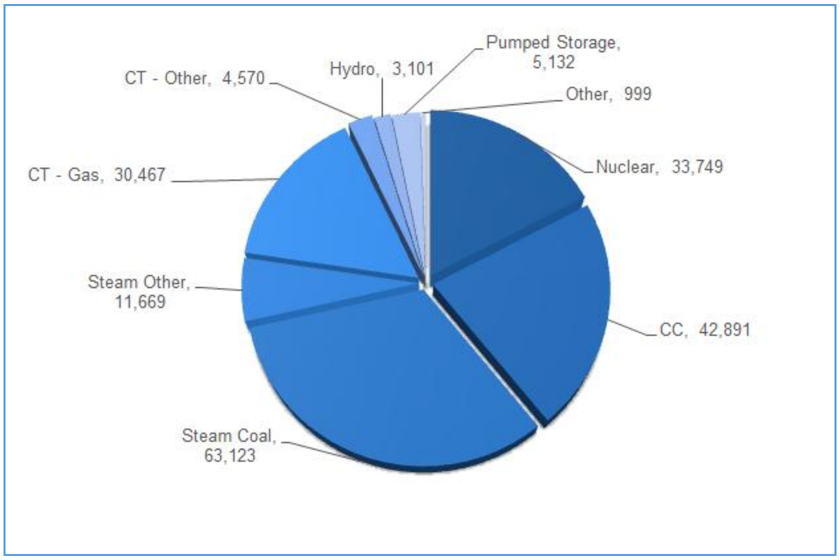

The following table is based on information provided by GE by unit and fuel type, listing (a) capacity in the base case (2018-2019); (b) existing capacity in 2014; (c) modeled additions; and (d) modeled retirements.

## Modeled MISO Capacity by Unit and Fuel Type

| | Summer Capacity (MW) | | | |
|---|---|---|---|---|
| | **2018-2019** | **2014** | **Additions** | **Retirements** |
| STEAM TURBINES | | | | |
| FOSSIL COAL 1-99 MW | 3,377 | 4,536 | | 1,159 |
| FOSSIL COAL 100-199 MW | 4,808 | 7,304 | | 2,496 |
| FOSSIL COAL 200-299 MW | 4,945 | 5,196 | | 251 |
| FOSSIL COAL 300-399 MW | 5,018 | 5,896 | | 878 |
| FOSSIL COAL 400-600 MW | 14,085 | 14,085 | | |
| FOSSIL COAL 600-799 MW | 23,186 | 23,186 | | |
| FOSSIL COAL 800-999 MW | 11,141 | 11,141 | | |
| FOSSIL COAL 1000+ MW | | | | |
| FOSSIL OIL 1-99 MW | 228 | 376 | | 148 |
| FOSSIL OIL 100-199 MW | | | | |
| FOSSIL OIL 200-299 MW | | | | |
| FOSSIL OIL 300-399 MW | | | | |
| FOSSIL OIL 400-599 MW | | | | |
| FOSSIL OIL 600-799 MW | | | | |
| FOSSIL OIL 800-999 MW | | | | |
| FOSSIL GAS 1-99 MW | 1,545 | 1,900 | | 355 |
| FOSSIL GAS 100-199 MW | 1,596 | 1,815 | | 219 |
| FOSSIL GAS 200-299 MW | 1,977 | 2,211 | | 234 |
| FOSSIL GAS 300-399 MW | 328 | 328 | | |
| FOSSIL GAS 400-599 MW | 5,983 | 5,983 | | |
| FOSSIL GAS 600-799 MW | 2,664 | 2,664 | | |
| FOSSIL GAS 800-999 MW | 2,012 | 2,012 | | |
| FOSSIL LIGNITE ALL | | | | |
| NUCLEAR ALL | 12,669 | 12,669 | | |
| BIOMASS ALL | 1,053 | 1,053 | | |
| OTHER ALL | 30 | 30 | | |
| COMBUSTION TURBINES | | | | |
| GAS COMB TURB 1-19 MW | 1,032 | 1,066 | | 34 |
| GAS COMB TURB 20-49 MW | 3,009 | 3,165 | | 156 |
| GAS COMB TURB 50+ MW | 19,698 | 19,698 | | |
| OIL COMB TURB 1-19 MW | 307 | 307 | | |
| OIL COMB TURB 20-49 MW | 807 | 857 | | 50 |
| OIL COMB TURB 50+ MW | 1,042 | 1,042 | | |
| BIOMASS COMB TURB ALL | 52 | 52 | | |
| OTHER COMB TURB ALL | | | | |
| COMBINED CYCLE | | | | |
| COMBINED CYCLE GAS ALL SIZE | 26,822 | 26,822 | | |
| COMBINED CYCLE OIL ALL SIZE | | | | |
| COMBINED CYCLE BIOMASS ALL SIZE | 24 | 24 | | |
| COMBINED CYCLE OTHER ALL SIZE | 892 | 892 | | |
| OTHER | | | | |
| HYDRO 1-29 MW | 1,081 | 1,052 | 30 | 1 |
| HYDRO 30+ MW | 270 | 270 | | |
| PUMP STG ALL SIZE | 2,339 | 2,339 | | |
| MULTBOIL/TURB ALL SIZE | | | | |
| GEOTHERMAL ALL SIZE | 49 | 49 | | |
| INTERNAL COMB BIOMASS ALL SIZE | 137 | 137 | | |
| INTERNAL COMB GAS ALL SIZE | 432 | 432 | | |
| INTERNAL COMB OIL ALL SIZE | 1,889 | 1,911 | | 22 |
| INTERNAL COMB OTHER ALL SIZE | 13 | 13 | | |
| OTHER ALL SIZE | | | | |
| TOTAL | 156,540 | 162,513 | 30 | 6,003 |

In PJM in 2018 - 2019 delivery year, the modeled summer capacity for non-intermittent generation totals 195,701 MW, and wind and solar nameplate capacity totals 7,796 MW.

**PJM Non-Intermittent Summer Installed Capacity (MW)**




The 195,701 MW of non-intermittent modeled summer capacity installed in PJM in 2018/19 is 9,994 MW higher than the summer installed capacity as of June 1, 2014. The growth in summer capacity is driven by a net increase in:

- Combined cycle (+17,375 MW),
- Non-coal steam (+1,641 MW),
- Combustion turbine (+796 MW), and
- Hydro generation (+459 MW)

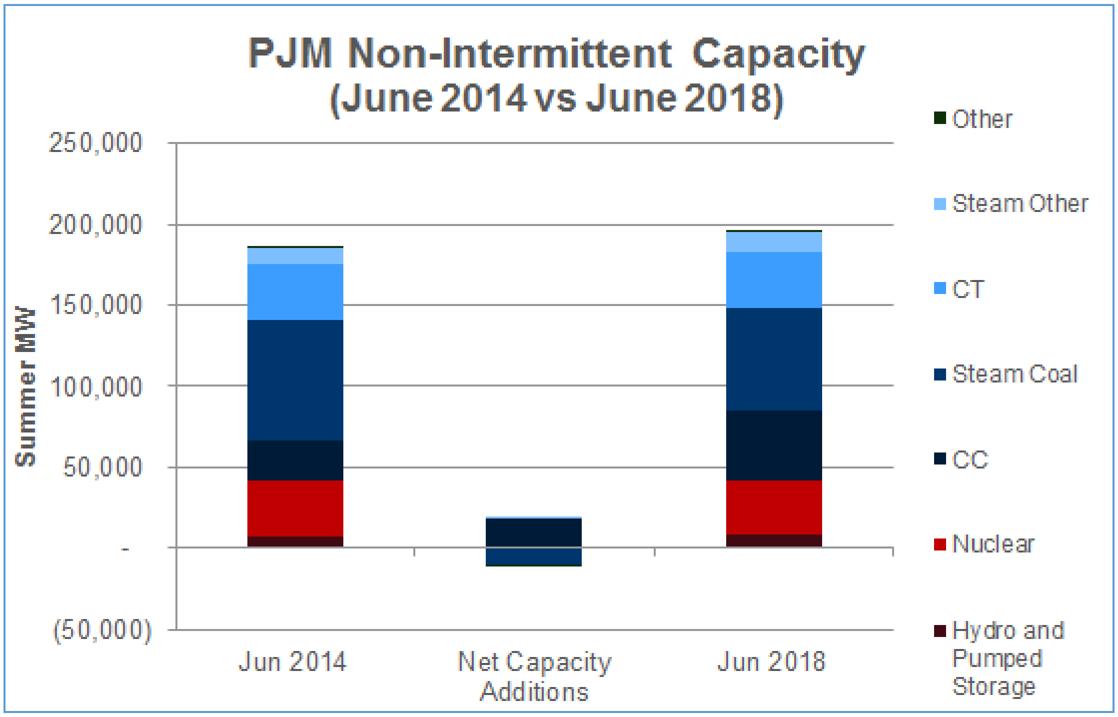
These net increases are also offset by net retirements of coal-fired generation totaling 10,276 MW and a decrease in internal combustion generation of 1 MW.

The following table is based on information provided by GE by unit and fuel type, listing (a) capacity in the base case (2018-2019); (b) existing capacity in 2014; (c) modeled additions; and (d) modeled retirements.

# Modeled PJM capacity by unit type

| | Summer Capacity (MW) | | | |
|---|---|---|---|---|
| | **6/1/18** | **6/1/14** | **Additions** | **Retirements** |
| STEAM TURBINES | | | | |
| FOSSIL COAL 1-99 MW* | 2,219 | 2,747 | | 529 |
| FOSSIL COAL 100-199 MW | 2,492 | 6,245 | | 3,753 |
| FOSSIL COAL 200-299 MW | 4,169 | 7,360 | | 3,191 |
| FOSSIL COAL 300-399 MW* | 3,733 | 4,651 | | 918 |
| FOSSIL COAL 400-600 MW | 7,687 | 8,187 | | 500 |
| FOSSIL COAL 600-799 MW | 20,133 | 20,718 | | 585 |
| FOSSIL COAL 800-999 MW | 13,593 | 14,393 | | 800 |
| FOSSIL COAL 1000+ MW | 9,097 | 9,097 | | |
| FOSSIL OIL 1-99 MW | 250 | 10 | 240 | |
| FOSSIL OIL 100-199 MW | 457 | 301 | 156 | |
| FOSSIL OIL 200-299 MW | 243 | | 243 | |
| FOSSIL OIL 300-399 MW | 760 | 760 | | |
| FOSSIL OIL 400-599 MW | 397 | 397 | | |
| FOSSIL OIL 600-799 MW | 1,164 | 1,164 | | |
| FOSSIL OIL 800-999 MW | 1,604 | 1,604 | | |
| FOSSIL GAS 1-99 MW | 347 | 455 | | 108 |
| FOSSIL GAS 100-199 MW | 896 | 1,341 | | 445 |
| FOSSIL GAS 200-299 MW | 415 | 415 | | |
| FOSSIL GAS 300-399 MW | | | | |
| FOSSIL GAS 400-599 MW | 450 | 450 | | |
| FOSSIL GAS 600-799 MW | | | | |
| FOSSIL GAS 800-999 MW | 1,700 | 1,700 | | |
| FOSSIL LIGNITE ALL | | | | |
| NUCLEAR ALL | 33,749 | 33,749 | | |
| BIOMASS ALL | 1,443 | 1,286 | 157 | |
| OTHER ALL | 1,544 | 146 | 1,397 | |
| COMBUSTION TURBINES | | | | |
| GAS COMB TURB 1-19 MW | 605 | 653 | 16 | 64 |
| GAS COMB TURB 20-49 MW | 2,239 | 3,353 | 181 | 1,295 |
| GAS COMB TURB 50+ MW | 27,623 | 24,942 | 3,815 | 809 |
| OIL COMB TURB 1-19 MW | 929 | 1,044 | | 115 |
| OIL COMB TURB 20-49 MW | 1,217 | 1,783 | | 566 |
| OIL COMB TURB 50+ MW | 2,258 | 2,665 | | 407 |
| BIOMASS COMB TURB ALL | 166 | 125 | 44 | 3 |
| OTHER COMB TURB ALL | | | | |
| COMBINED CYCLE | | | | |
| COMBINED CYCLE GAS ALL SIZE | 42,869 | 25,494 | 17,375 | |
| COMBINED CYCLE OIL ALL SIZE | | | | |
| COMBINED CYCLE BIOMASS ALL SIZE | 22 | 22 | | |
| COMBINED CYCLE OTHER ALL SIZE | | | | |
| OTHER | | | | |
| HYDRO 1-29 MW | 630 | 605 | 24 | |
| HYDRO 30+ MW | 2,471 | 2,037 | 434 | |
| PUMP STG ALL SIZE | 5,132 | 5,132 | | |
| MULTBOIL/TURB ALL SIZE | | | | |
| GEOTHERMAL ALL SIZE | | | | |
| INTERNAL COMB BIOMASS ALL SIZE | 278 | 278 | | |
| INTERNAL COMB GAS ALL SIZE | 133 | 133 | | |
| INTERNAL COMB OIL ALL SIZE | 558 | 559 | 14 | 15 |
| INTERNAL COMB OTHER ALL SIZE | | | | |
| OTHER ALL SIZE | 30 | 30 | | |
| TOTAL | 195,701 | 185,707 | 24,096 | 14,103 |

**Changes in PJM Non-Intermittent Summer Installed Capacity from 2014 to 2018**




## C.4. Inter-area and Inter-zonal Transfer Capabilities

While both MISO and PJM are modeled as islands with external transfers assumed to net to zero in 2018/19, GE-MARS does model exchanges of capacity between LBAs in MISO and between transmission zones in PJM.

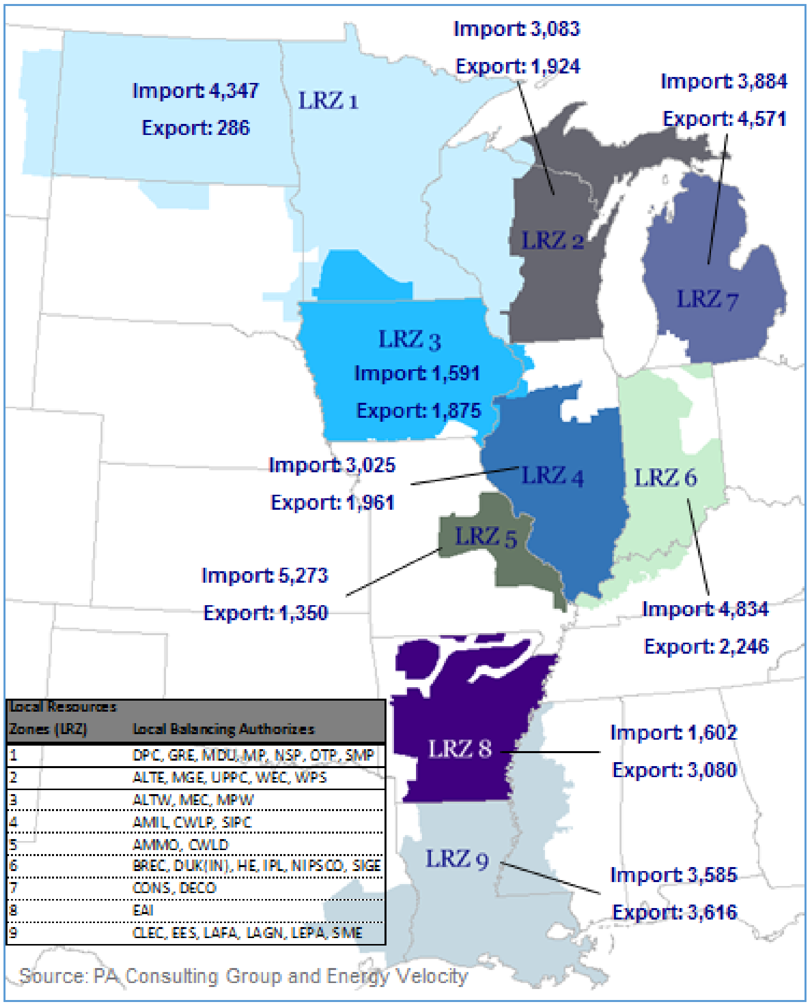
Modeling MISO and PJM with a net external transfer equal to zero is a conservative approach as both MISO and PJM account for net transfers from external regions that are assumed to be greater than zero in MISO 2014 LOLE Study and Draft 2014 PJM Reserve Requirement Study. These net imports are termed the "capacity benefit margin". The capacity benefit margin was eliminated in the GE-MARS modeling because the availability of capacity external to each market might change dramatically if, for instance, capacity currently located in MISO decides to interconnect with PJM as Dynegy has suggested it may pursue[30].

Allowing for capacity transfers between LBAs in MISO is different than how MISO conducts its LOLE study. MISO projects the LOLE in each LRZ as well as RTO-wide. When modeling individual LRZ, MISO models no transfers and then solves for the maximum that could be imported and exported from LRZs while maintaining the Reliability Standard. LRZ reliability results reported by MISO are in the absence of interzonal support. In GE-MARS, the

[30] http://www.rtoinsider.com/dynegy-miso-capacity-pjm/.

MISO transmission import and export limits modeled for each LZR based on those determined in the MISO 2014 LOLE Study[31].

**MISO LRZ Transmission Limits**

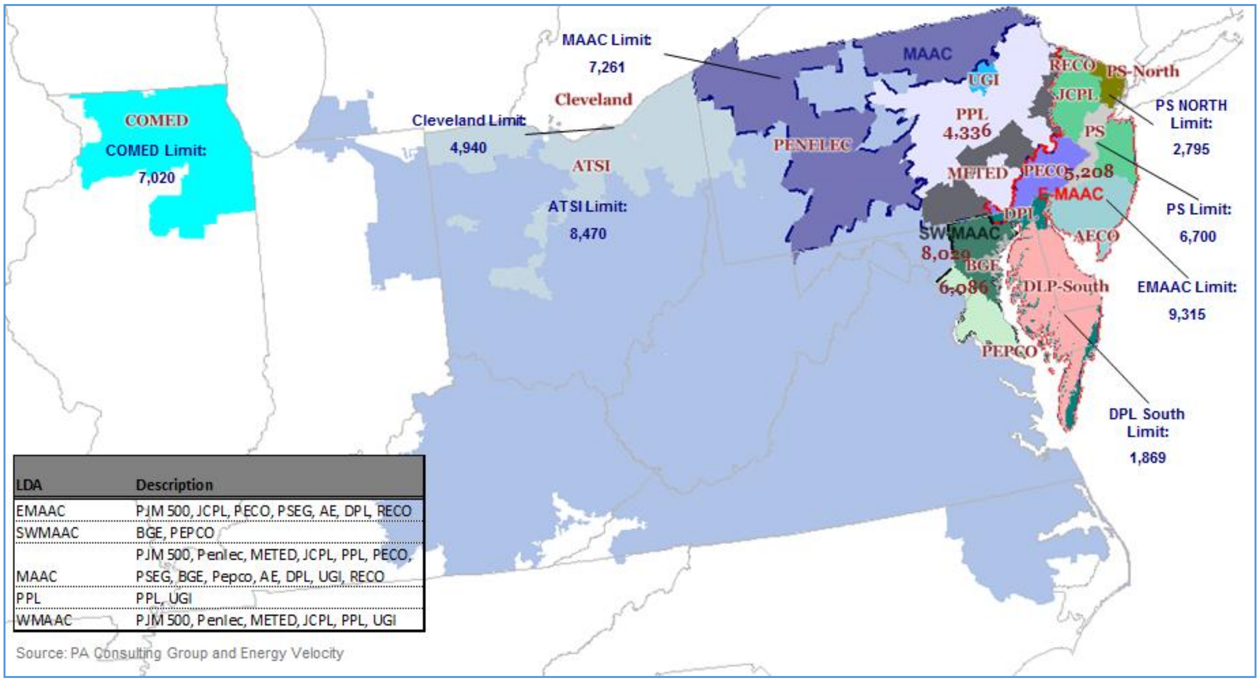



In PJM, transmission limits in GE-MARS reflect those used by PJM in their 2017/18 RPM BRA[32]. This means that GE-MARS is only modeling limits on transmission between the transmission zones that PJM has determined are close to requiring capacity imports to meet their reserve requirement.

[31] https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20LOLE%20Study%20Report.pdf.

[32] http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-rpm-bra-planning-parameters-report.ashx.

**PJM Transmission Limits**




| LDA | Description |
|---|---|
| EMAAC | PJM 500, JCPL, PECO, PSEG, AE, DPL, RECO |
| SWMAAC | BGE, PEPCO |
| MAAC | PJM 500, Penlec, METED, JCPL, PPL, PECO, PSEG, BGE, Pepco, AE, DPL, UGI, RECO |
| PPL | PPL, UGI |
| WMAAC | PJM 500, Penlec, METED, JCPL, PPL, UGI |

Source: PA Consulting Group and Energy Velocity

### C.5. Unit Outage Rates

Unit outage rates used in GE-MARS are based on NERC Generator Availability Data System (“GADS”) data. GADS event data includes a description of equipment failures that reports, among other things, when the event started and ended and the outage type (e.g. forced, maintenance, planned, etc.). The unit equivalent forced outage rate (“EFOR”) is calculated from the GADS event data. EFOR is equal to the hours of unit failure (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of unit availability.

An average EFOR rate is modeled for each unit type to denote the probability that a unit will experience a forced outage in GE-MARS. The sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. Refer to Appendix J for the unit EFOR and planed outage rates used in GE-MARS.

Load scenarios represent the fact that the load forecast is imperfect; the load scenarios are independent of outage scenarios and the forecasts vary randomly (with a standard deviation of 4.3% of the forecast in each of MISO and PJM).

# Appendix D. Load forecasts for Polar Vortex and High Load and High Coal Retirements Cases

## D.1. Polar Vortex, MISO

The MISO Polar Vortex winter load forecast increase is determined based on the percent difference between the actual peak hour load of 109,307 MW experienced during the January 2014 polar vortex[33] and a coincident peak load forecast. The coincident peak load forecast was calculated using the 2013/14 winter non-coincident peak load forecast of 106,180 MW[34] and the ratio of 2014 winter non-coincident to coincident peak load used by the MARS model. Because the *MISO 2013-14 Winter Coordinated Seasonal Transmission Assessment* does not include a coincident winter peak load forecast to compare to the actual coincident peak load experienced during the polar vortex, the winter 2013/14 non-coincident peak load forecast was converted to a coincident peak load forecast by using the ratio of the 2018 winter non-coincident to coincident peak load determined by the MARS load model in the Base Case.

An example of the process follows. Given:

(a) 109,307 MW 2014 coincident winter peak load experienced during the polar vortex (cited above)
(b) 106,180 MW 2014 non-coincident winter peak load forecast (cited above)
(c) 97,500 MW winter 2018 coincident peak from MARS Base Case
(d) 102,400 MW winter 2018 non-coincident peak from MARS Base Case

Solve for:

(e) 2014 coincident winter peak load forecast
(f) ratio of (a) winter coincident peak load experienced during the polar vortex to (e) 2014 forecasted coincident winter peak load

Using the equations:

(e) = (b) x (c/d), or (e) = 106,180 x (97,500/102,400) = 101,099
(f) = (a)/(e), or (f) = 109,307/101,099 = 1.0811 (i.e. 8.1%)

## D.2. Polar Vortex Case, PJM

The PJM Polar Vortex winter load forecast increase is determined based on the percent difference between the actual peak hour load of 141,846 MW experienced during the January 2014 polar vortex[35] and a coincident peak load forecast. The coincident peak load forecast was calculated using the 2013/14 winter non-coincident peak load forecast of 135,667 MW and the ratio of 2014 summer non-coincident to coincident peak load .[36] Because the *2013 PJM Load*

[33] MISO ENGCTF Issue Summary Paper: MISO and Stakeholder Polar Vortex Experiences with Natural Gas Availability and Enhanced RTO/Pipeline Communication, Sept. 23, 2014, page 8.

[34] MISO 2013-14 Winter Coordinated Seasonal Transmission Assessment.

[35] PJM Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events, May 8, 2014, page 4

[36] 2013 PJM Load Forecast Report, Table B-2

*Forecast Report* does not include a coincident winter peak load forecast to compare to the actual coincident peak load experienced during the polar vortex, the 2013/14 non-coincident peak load forecast was converted to a coincident peak load forecast by using the ratio of the 2014 summer non-coincident to coincident peak load contained in the *2013 PJM Load Forecast Report*.

An example of the process follows:
Given:

(a) 141,846 MW 2014 coincident winter peak load experienced during the polar vortex (cited above)
(b) 135,667 MW 2014 non-coincident winter peak load forecast (cited above)
(c) 158,718 MW summer 2014 coincident peak from 2013 PJM Load Forecast Report
(d) 165,413 MW summer 2018 non-coincident peak from 2013 PJM Load Forecast Report

Solve for:

(e) 2014 coincident winter peak load forecast
(f) ratio of (a) winter coincident peak load experienced during the polar vortex to (e) 2014 forecasted coincident winter peak load

Using the equations:

(e) = (b) x (c/d), or (e) = 135,667 x (158,718/165,413) = 130,176
(f) = (a)/(e), or (f) = 141,846/130,176 = 1.0896 (i.e. 9.0%)

### D.3. High Load and High Coal Retirements Case, MISO and PJM

Peak hour load and annual energy increases for both MISO and PJM are based on the increase in PJM summer extreme weather peak load forecast of 181,426 MW for 2018[37] relative to the median summer peak load forecast of 171,347 MW for 2018[38]. The PJM summer extreme weather peak hour load forecast for 2018 is 6% higher than the median summer peak hour load forecast. A high annual energy forecast was not provided in the PJM report therefore the 6% increase in the peak hour load was also applied to annual energy. A high peak hour load forecast was not available for MISO, so the 6% increase was also applied to MISO peak load and energy forecasts. Applying a 6% increase to the energy forecast for PJM and to the peak load and energy forecasts for MISO is a reasonable assumption based on professional judgment.

[37] 2014 PJM Load Forecast Report, January 2014, Table D-1

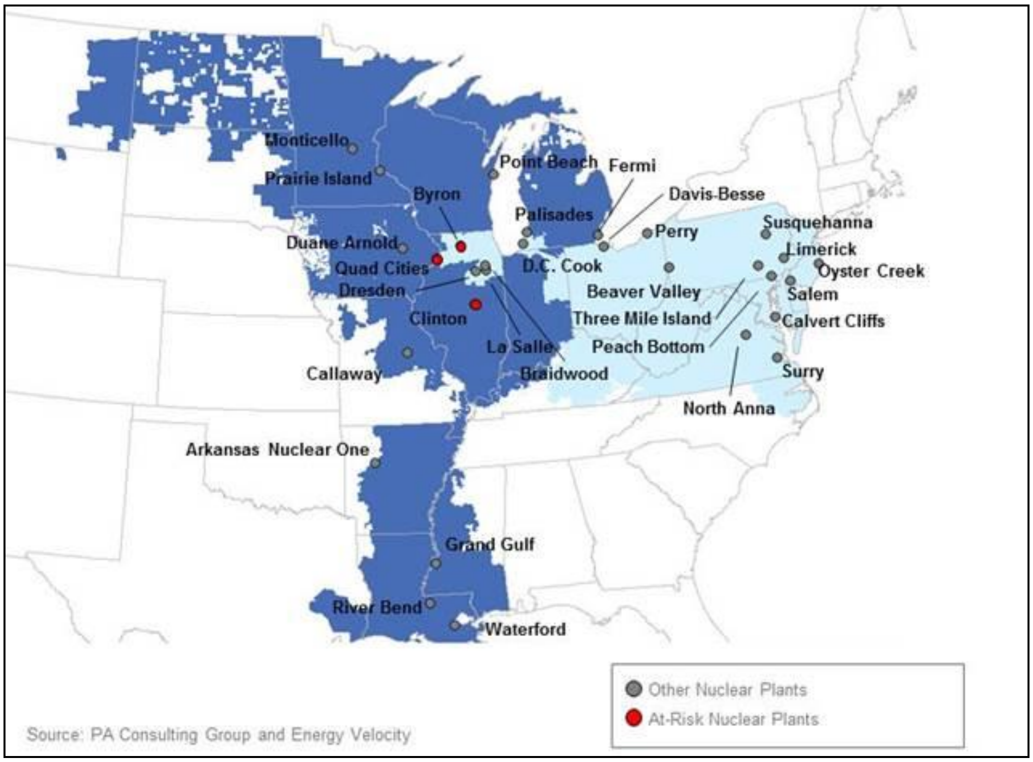
[38] 2014 PJM Load Forecast Report, January 2014, Table B-1

## Appendix E. MISO and PJM Nuclear Fleet

There are 33 nuclear units in PJM totaling 33,749 MW of summer capacity and 15 nuclear units in MISO totaling 12,669 MW of summer capacity[39].

Of the 48 nuclear units located in MISO and PJM all but one, Davis-Besse, currently hold licenses to operate beyond 2020, and FirstEnergy Nuclear Operating Company has filed a license renewal application for Davis-Besse[40] with the Nuclear Regulatory Commission.

**MISO and PJM Nuclear Fleet**




[39] http://www.nrc.gov/info-finder/reactor/index.html.

[40] http://www.nrc.gov/reactors/operating/licensing/renewal/applications/davis-besse/davis-besse-lra.pdf.

## PJM Nuclear Units

| PJM Nuclear Units | | | | | |
|---|---|---|---|---|---|
| Plant Name | Plant State | Nameplate Capacity MW | Net Summer Capacity MW | Commercial Online Date | License expiration Date |
| Beaver Valley 1 | Pennsylvania | 1,011 | 892 | Sep 1976 | Jan 2036 |
| Beaver Valley 2 | Pennsylvania | 1,011 | 914 | Nov 1987 | May 2047 |
| Braidwood Generation Station 1 | Illinois | 1,307 | 1,178 | Jul 1988 | Oct 2026 |
| Braidwood Generation Station 2 | Illinois | 1,283 | 1,152 | | Dec 2027 |
| Byron Generating Station (IL) 1 | Illinois | 1,307 | 1,164 | Sep 1985 | Oct 2024 |
| Byron Generating Station (IL) 2 | Illinois | 1,307 | 1,136 | Aug 1987 | Nov 2026 |
| Calvert Cliffs Nuclear Power Plant 1 | Maryland | 1,050 | 866 | May 1975 | Jul 2034 |
| Calvert Cliffs Nuclear Power Plant 2 | Maryland | 961 | 850 | Apr 1977 | Aug 2036 |
| Davis Besse 1 | Ohio | 970 | 894 | Nov 1977 | Apr 2017 |
| Donald C Cook 1 | Michigan | 1,171 | 1,009 | Aug 1975 | Oct 2034 |
| Donald C Cook 2 | Michigan | 1,154 | 1,060 | Jul 1978 | Dec 2037 |
| Dresden 2 | Illinois | 924 | 883 | Jun 1970 | Dec 2029 |
| Dresden 3 | Illinois | 928 | 867 | Nov 1971 | Jan 2031 |
| Hope Creek 1 | New Jersey | 1,291 | 1,174 | Dec 1986 | Apr 2046 |
| LaSalle 1 | Illinois | 1,243 | 1,137 | Aug 1982 | Apr 2022 |
| LaSalle 2 | Illinois | 1,243 | 1,140 | Apr 1984 | Dec 2023 |
| Limerick 1 | Pennsylvania | 1,212 | 1,146 | Feb 1986 | Oct 2024 |
| Limerick 2 | Pennsylvania | 1,212 | 1,150 | Jan 1990 | Jun 2029 |
| North Anna 1 | Virginia | 1,006 | 943 | Jun 1978 | Apr 2038 |
| North Anna 2 | Virginia | 1,052 | 943 | Dec 1980 | Aug 2040 |
| Oyster Creek (NJ) 1 | New Jersey | 550 | 615 | Dec 1969 | Apr 2029 |
| Peach Bottom 2 | Pennsylvania | 1,229 | 1,125 | Jul 1974 | Aug 2033 |
| Peach Bottom 3 | Pennsylvania | 1,229 | 1,125 | Dec 1974 | Jul 2034 |
| Perry (OH) 1 | Ohio | 1,313 | 1,240 | Nov 1987 | Mar 2026 |
| PSEG Salem Generating Station 1 | New Jersey | 1,251 | 1,168 | Jun 1977 | Aug 2036 |
| PSEG Salem Generating Station 2 | New Jersey | 1,216 | 1,158 | Oct 1981 | Apr 2040 |
| Quad Cities (EXELON) 1 | Illinois | 1,009 | 908 | Dec 1972 | Dec 2032 |
| Quad Cities (EXELON) 2 | Illinois | 1,009 | 911 | Dec 1972 | Dec 2032 |
| Surry 1 | Virginia | 928 | 838 | Dec 1972 | May 2032 |
| Surry 2 | Virginia | 928 | 838 | May 1973 | Jan 2033 |
| Susquehanna 1 | Pennsylvania | 1,344 | 1,260 | Jun 1983 | Jul 2042 |
| Susquehanna 2 | Pennsylvania | 1,344 | 1,260 | Feb 1985 | Mar 2044 |
| Three Mile Island 1 | Pennsylvania | 976 | 805 | Aug 1974 | Apr 2034 |
| Total PJM Nuclear Capacity: | | 36,968 | 33,749 | | |

## MISO Nuclear Units

| MISO Nuclear Units | | | | | |
|---|---|---|---|---|---|
| Plant Name | Plant State | Nameplate Capacity MW | Net Summer Capacity MW | Commercial Online Date | License expiration Date |
| Arkansas Nuclear One 1 | Arkansas | 903 | 836 | Dec 1974 | May 2034 |
| Arkansas Nuclear One 2 | Arkansas | 1,013 | 992 | Mar 1980 | Jul 2038 |
| Callaway (MO) 1 | Missouri | 1,296 | 1,190 | Dec 1984 | Oct 2024 |
| Clinton Power Station (IL) 1 | Illinois | 1,188 | 1,065 | Nov 1987 | Sep 2026 |
| Duane Arnold 1 | Iowa | 660 | 619 | Feb 1975 | Feb 2034 |
| Fermi NB 2 | Michigan | 1,236 | 1,085 | Jan 1988 | Mar 2025 |
| Grand Gulf Nuclear Station 1 | Mississippi | 1,574 | 1,190 | Jul 1985 | Nov 2024 |
| Monticello (MN) 1 | Minnesota | 671 | 554 | Jan 1971 | Sep 2030 |
| Palisades (MI) 1 | Michigan | 823 | 782 | Mar 1972 | Mar 2031 |
| Point Beach 1 | Wisconsin | 643 | 591 | Dec 1970 | Oct 2030 |
| Point Beach 2 | Wisconsin | 643 | 591 | Oct 1972 | Mar 2033 |
| Prairie Island 1 | Minnesota | 593 | 521 | Feb 1974 | Aug 2033 |
| Prairie Island 2 | Minnesota | 593 | 519 | Oct 1974 | Oct 2034 |
| River Bend NB1 | Louisiana | 1,054 | 975 | Jan 1986 | Aug 2025 |
| Waterford 3 | Louisiana | 1,315 | 1,159 | Sep 1985 | Dec 2024 |
| Total MISO Nuclear Capacity: | | 14,205 | 12,669 | | |

# Appendix F. GE-MARS Program Description

## F.1. GE-MARS Program Description

GE-MARS performs a sequential Monte Carlo simulation to assess the reliability of a generation system comprised of any number of interconnected areas. In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly-generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies that govern system operation.

## F.2. Loads

The loads in GE-MARS are modeled on an hourly, chronological basis for each area being studied. The program has the option to modify the input hourly loads through time to meet specified annual or monthly peaks and energies. Uncertainty on the annual peak load forecast can also be modeled, and can vary by area on a monthly basis.

## F.3. Generation

GE-MARS has the capability to model the following different types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand-side management

Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management are modeled as load modifiers.

For each unit modeled, the user specifies the installation and retirement dates and planned maintenance requirements. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in GE-MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on an area, pool, or system basis. GE-MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

### a. Thermal Units

In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as a result of the outages of various unit components.

Because GE-MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

$$\text{TR (A to B)} = \frac{\text{Number of Transitions from A to B}}{\text{Total Time in State A}}$$

If detailed transition rate data for the units is not available, GE-MARS can approximate the transitions rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

**b. Energy-Limited Units**

Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

### c. Cogeneration

GE-MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

### d. Energy-Storage and DSM

Energy-storage units and demand-side management are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week that is subtracted from the hourly loads for the unit's area.

## F.4. Transmission System

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. Simultaneous transfer limits can also be modeled in which the total flow on user-defined groups of interfaces is limited. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

The transfer limits are specified for each direction of the interface or interface group and can be input on a monthly basis. The transfer limits can also vary hourly according to the availability of specified units and the value of area loads.

## F.5. Emergency Operating Procedures

Emergency operating procedures are steps undertaken by a utility system as the reserve conditions on the system approach critical levels. They consist of load control and generation supplements that can be implemented before load has to be actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Generation supplements could include overloading units, emergency purchases, and reduced operating reserves.

The need for a utility to begin emergency operating procedures is modeled in GE-MARS by evaluating the daily LOLE at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

The user can also specify monthly limits on the number of times that each emergency procedure is initiated, and whether each EOP benefits only the area itself, other areas in the same pool, or areas throughout the system. Staggered implementation of EOPs, in which the deficient area must initiate a specified number of EOPs before non-deficient areas begin implementation, can also be modeled.

### F.6. Resource Allocation Among Areas

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins.

## Appendix G. MISO LRZs and LBAs

**Local Resource Zones and Local Balancing Authorities in MISO**

| MISO Local Resource Zone | MISO Local Balancing Authority | MISO Local Balancing Authority Long Name |
|---|---|---|
| LRZ 1 | DPC | Dairyland Power Cooperative |
| | GRE | Great River Energy |
| | MDU | Montana-Dakota Utilities Co. |
| | MP | Minnesota Power Inc. |
| | NSP | Northern States Power Company |
| | OTP | Otter Tail Power Company |
| | SMP | Southern Minnesota Municipal Power Agency |
| LRZ 2 | ALTE | Alliant Energy East |
| | MGE | Madison Gas and Electric Company |
| | UPPC | Upper Peninsula Power Co. |
| | WEC | Wisconsin Energy Corporation |
| | WPS | Wisconsin Public Service Corporation |
| LRZ 3 | ALTW | Alliant Energy West |
| | MEC | MidAmerican Energy Company |
| | MPW | Muscatine Power and Water |
| LRZ 4 | AMIL | Ameren Illinois |
| | CWLP | City Water Light & Power |
| | SIPC | Southern Illinois Power Cooperative |
| LRZ 5 | AMMO | Ameren Missouri |
| | CWLD | Columbia Water & Light |
| LRZ 6 | BREC | Big Rivers Electric Corporation |
| | DUK (IN) | Duke Energy Indiana |
| | HE | Hoosier Energy |
| | IPL | Indianapolis Power & Light Company |
| | NIPSCO | Northern Indiana Public Service Company |
| | SIGE | Southern Indiana Gas & Electric Co. |
| LRZ 7 | CONS | Consumers Energy Company |
| | DECO | Detroit Edison Company |
| LRZ 8 | EAI | Entergy Arkansas |
| LRZ 9 | CLEC | Cleco |
| | EES | Entergy |
| | LAFA | City of Lafayette |
| | LAGN | Louisiana Generation |
| | LEPA | Louisiana Electric Power Authority |
| | SME | Southern Mississippi Electric Power Association |

## Appendix H. PJM Transmission Zones

**Transmission Zones in PJM**

| PJM Transmission Zone | PJM Transmission Zone Long Name |
|---|---|
| AECO | Atlantic Electric Company |
| AEP | American Electric Power |
| APS | Allegheny Power System |
| BGE | Baltimore Gas and Electric Company |
| COMED | Commonwealth Edison |
| DAY | Dayton Power and Light Company |
| DOM | Dominion Virginia Electric Power |
| DPL | Delmarva Power and Light |
| DUK-KY | Duke Energy Corporation – Kentucky |
| DUK-OH | Duke Energy Corporation – Ohio |
| DUQ | Duquesne Lighting Company |
| EKPC | East Kentucky Power Cooperative |
| FE-ATSI | First Energy |
| JCPL | Jersey Central Power and Light Company |
| METED | Metropolitan Edison Company |
| PECO | PECO Energy Company |
| PENELEC | Pennsylvania Electric Company |
| PEPCO | Potomac Electric Power Company |
| PPL | Pennsylvania Power & Light Company |
| PSEG | Public Service Electric & Gas Company |
| RECO | Rockland Electric Company |
| UGI | UGI Utilities, Inc. |

## Appendix I. MISO Peak Hour Load and Annual Energy Forecast Methodology

The GE-MARS used a PJM peak load forecast from the RTO. Because of concerns around the MISO-South integration and discrepancies noted in published MISO forecasts, it was necessary to produce an independent forecast of the MISO peak load based on GE's economic forecast.

The first step to the MISO annual load forecast is developing annual growth rates for the continental United States. This forecast is derived from a linear regression of historical electricity intensity from 1990 to present. Electricity intensity is the total annual electricity consumption divided by annual GDP. The source of historical GDP data is the U.S. Bureau of Economic Analysis[41], and the source of the total annual electricity consumption is the most recent EIA Monthly Energy Review, Table 7.6, Electricity by End Use, Total Retail Sales[42].

The historical data of electricity intensity has been steadily declining for many years due to sectorial shifts in the economy and overall energy efficiency. A linear regression is applied to the historical data ($y = ax + b$), where y represents electricity intensity and x represents the number of years since 1990. Coefficients a and b are estimated and used to forecast future electricity intensity. 1990 is used as the starting point of the regression due to capture recent trends in energy efficiency and other shifts in the economy (i.e. offshoring of heavy industry). The assumption used in the US load forecast is that this declining trend in electricity intensity (energy efficiency) will continue linearly through 2030.

With the linear regression formula, a US GDP forecast can then be used as the basis of the U.S. electricity demand forecast. For example, the regression equation can be used to calculate the expected electricity intensity for a future year. This is then multiplied by the forecasted GDP value to develop a corresponding electricity demand forecast. The current GDP forecast is based on the mean central tendency from the US Federal Reserve's December economic forecast[43]. The current forecast is around 3% annual growth in the near-term (through 2016), and 2.3% growth in the long term.

The percent annual growth rate for the United States is then applied to the NERC Energy Supply and Demand (ESD)[44] Net Energy for Load forecast so that the annual load growth can be divided to sub-regions across North America (the overall GE-MARS pool topology follows the NERC Assessment Area boundaries). For example, if PJM is 20% of the total U.S. NERC Net Energy for Load in 2013, 20% of the U.S. annual load forecast is allocated to the PJM GE-MARS pool. This is done for each NERC Assessment Area in each year of the forecast, which allows for different relative growth rates for different regions. As a result, faster growing regions in the southwestern U.S. will increase their share of the U.S. total.

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[41] US Bureau of Economic Analysis: http://www.bea.gov/national/index.htm#gdp

[42] EIA Monthly Energy Review: http://www.eia.gov/totalenergy/data/monthly/#electricity

[43] US Federal Reserve Economic Forecast: http://www.federalreserve.gov/monetarypolicy/mpr_default.htm. The December forecast is described in the "February report" available at that page.

[44] NERC ESD: http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx

Also forecasted is the annual peak demand by GE-MARS Pool (NERC Assessment Area). This is done by applying the calculated load factor in the NERC ESD to the updated annual net energy for load forecast. For example, if the GE-MARS PJM annual energy for a year is 2% lower than the annual energy reported in the NERC ESD, the same load factor is applied to the lower number leading to a lower overall peak demand. This allows for changes in load factor over time due to shifting load profiles from industrial to residential (higher load factor). The NERC ESD and corresponding Long Term Reliability Assessment[45] are published annually in December and can be found online using the links at the bottom of this section.

Another change made to the NERC ESD data relates to the starting point of the annual net energy for load forecast. Due to the relatively long lead time in publishing the data, often an additional year of historical reported load data is available. In order to capture the most recent trends in load, the starting point of the NERC ESD US Net Energy for Load forecast (in this case the year 2013) is scaled up or down based on the most recent year of data. This is done using the Edison Electric Institute (EEI) estimate of weather normalized load growth, relative to the prior year's actual load.

Once the load forecast is completed on the GE-MARS Pool (NERC Assessment Area) level, loads are again subdivided into smaller GE-MARS Areas in order to align with the hourly load profiles embedded in the model. The topology of the GE-MARS Areas follows the Ventyx Transmission Zone boundaries, which correspond to the MISO LBAs. The initial annual peak and energy targets for each MAPS Area is from the Ventyx "Historical and Forecast Demand by Zone" dataset. However, a load EPCL developed by GE is used to scale the area loads up or down in order to achieve the aggregated pool-level peak and energy targets.

Finally, the program uses the non-coincident peak load and annual energy forecasts for each MISO LBA and PJM transmission zone to scale the hourly load profiles for each area.

[45] NERC 2013 LTRA: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf

# Appendix J. GE-MARS EFOR and Planned Outage Rates

## Generic Outage Rates Used in GE-MARS

| Unit Type | EFOR | | | Planned Outage Rate | |
|---|---|---|---|---|---|
| | Base Case | Polar Vortex Case[46] | | Base Case | Polar Vortex Case |
| | MISO & PJM | MISO | PJM | MISO & PJM | MISO & PJM |
| FOSSIL COAL 1-99 MW | 0.1064 | 0.1953 | 0.3925 | 0.0693 | 0.0693 |
| FOSSIL COAL 100-199 MW | 0.0630 | 0.1156 | 0.2324 | 0.0840 | 0.0840 |
| FOSSIL COAL 200-299 MW | 0.0710 | 0.1303 | 0.2619 | 0.0972 | 0.0972 |
| FOSSIL COAL 300-399 MW | 0.0685 | 0.1257 | 0.2527 | 0.0903 | 0.0903 |
| FOSSIL COAL 400-600 MW | 0.0782 | 0.1435 | 0.2885 | 0.1044 | 0.1044 |
| FOSSIL COAL 600-799 MW | 0.0671 | 0.1231 | 0.2475 | 0.1004 | 0.1004 |
| FOSSIL COAL 800-999 MW | 0.0465 | 0.0853 | 0.1715 | 0.0949 | 0.0949 |
| FOSSIL COAL 1000+ MW | 0.0862 | 0.0862 | 0.3180 | 0.1088 | 0.1088 |
| FOSSIL OIL 1-99 MW | 0.0354 | 0.0354 | 0.0615 | 0.0884 | 0.0884 |
| FOSSIL OIL 100-199 MW | 0.0560 | 0.0560 | 0.0972 | 0.0986 | 0.0986 |
| FOSSIL OIL 200-299 MW | 0.1059 | 0.1059 | 0.1838 | 0.1132 | 0.1132 |
| FOSSIL OIL 300-399 MW | 0.0453 | 0.0453 | 0.0786 | 0.1564 | 0.1564 |
| FOSSIL OIL 400-599 MW | 0.0445 | 0.0445 | 0.0772 | 0.1093 | 0.1093 |
| FOSSIL OIL 600-799 MW | 0.4126 | 0.4126 | 0.7162 | 0.1224 | 0.1224 |
| FOSSIL OIL 800-999 MW | 0.1436 | 0.1436 | 0.2493 | 0.1994 | 0.1994 |
| FOSSIL GAS 1-99 MW | 0.1255 | 0.4607 | 0.640 | 0.0562 | 0.0562 |
| FOSSIL GAS 100-199 MW | 0.0728 | 0.2672 | 0.3712 | 0.0932 | 0.0932 |
| FOSSIL GAS 200-299 MW | 0.0667 | 0.2448 | 0.3401 | 0.1117 | 0.1117 |
| FOSSIL GAS 300-399 MW | 0.0541 | 0.1986 | n/a | 0.1047 | 0.1047 |
| FOSSIL GAS 400-599 MW | 0.0906 | 0.3326 | 0.4620 | 0.1224 | 0.1224 |
| FOSSIL GAS 600-799 MW | 0.0948 | 0.3480 | n/a | 0.1308 | 0.1308 |
| FOSSIL GAS 800-999 MW | 0.0193 | 0.0708 | 0.0984 | 0.0908 | 0.0908 |
| FOSSIL LIGNITE ALL | 0.0629 | 0.0629 | 0.1557 | 0.0713 | 0.0713 |
| NUCLEAR ALL 400-799 MW | 0.0284 | 0.0284 | 0.0284 | 0.1218 | 0.1218 |
| NUCLEAR ALL 800-999 MW | 0.0345 | 0.0345 | 0.0345 | 0.0669 | 0.0669 |
| NUCLEAR ALL 1000+ MW | 0.0286 | 0.0286 | 0.0286 | 0.0674 | 0.0674 |
| GAS COMB TURB 1-19 MW | 0.1973 | 0.7242 | 1.0000 | 0.0523 | 0.0523 |
| GAS COMB TURB 20-49 MW | 0.1056 | 0.3876 | 0.5385 | 0.0368 | 0.0368 |
| GAS COMB TURB 50+ MW | 0.0725 | 0.2661 | 0.3697 | 0.0518 | 0.0518 |
| OIL COMB TURB 1-19 MW | 0.1973 | 0.1973 | 0.3425 | 0.0523 | 0.0523 |
| OIL COMB TURB 20-49 MW | 0.1056 | 0.1056 | 0.1833 | 0.0368 | 0.0368 |
| OIL COMB TURB 50+ MW | 0.0725 | 0.0725 | 0.1259 | 0.0518 | 0.0518 |
| OTHER COMB TURB 1-19 MW | 0.1973 | 0.1013 | 0.1973 | 0.0523 | 0.0523 |
| OTHER COMB TURB 20-49 MW | 0.1056 | 0.1013 | 0.1056 | 0.0368 | 0.0368 |
| OTHER COMB TURB 50+ MW | 0.0725 | 0.1013 | 0.0725 | 0.0518 | 0.0518 |
| COMBINED CYCLE GAS ALL SIZE | 0.0435 | 0.1597 | 0.2218 | 0.0848 | 0.0848 |
| COMBINED CYCLE OIL ALL SIZE | 0.0435 | 0.0435 | 0.0755 | 0.0848 | 0.0848 |
| COMBINED CYCLE OTHER ALL SIZE | 0.0435 | 0.0435 | 0.0755 | 0.0848 | 0.0848 |
| HYDRO 1-29 MW | 0.0781 | 0.0819 | 0.1356 | 0.1008 | 0.1008 |
| HYDRO 30+ MW | 0.0358 | 0.0375 | 0.0621 | 0.1069 | 0.1069 |
| PUMP STG ALL SIZE | 0.0490 | 0.0514 | 0.0851 | 0.1065 | 0.1065 |
| MULTBOIL/TURB ALL SIZE | 0.0897 | 0.0941 | 0.1557 | 0.0437 | 0.0437 |
| GEOTHERMAL ALL SIZE | 0.0095 | 0.0100 | 0.0095 | 0.0207 | 0.0207 |
| INTERNAL COMB GAS ALL SIZE | 0.1247 | 0.4577 | 0.6359 | 0.0218 | 0.0218 |
| INTERNAL COMB OIL ALL SIZE | 0.1247 | 0.0327 | 0.2165 | 0.0218 | 0.0218 |
| INTERNAL COMB OTHER ALL SIZE | 0.1247 | 0.1308 | 0.2165 | 0.0218 | 0.0218 |

[46] n/a indicates there are no plants of that size and type in the RTO

## Appendix K. MISO LBA LOLE by Case

**Forecasted Loss of Load Expectation in MISO, by Scenario and Local Balancing Authority**

| MISO LBA | LOLE with Demand Response | | | | LOLE without Demand Response | | | |
|---|---|---|---|---|---|---|---|---|
| | **Base Case** | **Nuclear Retirement Case** | **Polar Vortex Case[47]** | **High Load and Coal Retirement Case** | **Base Case** | **Nuclear Retirement Case** | **Polar Vortex Case[48]** | **High Load and Coal Retirement Case** |
| ALTE | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| ALTW | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.001 |
| AMIL | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.002 |
| AMMO | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| BREC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CONS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CWLD | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CWLP | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| DECO | 0.000 | 0.000 | 0.000 | 0.004 | 0.000 | 0.000 | 0.000 | 0.079 |
| DPC | 0.000 | 0.000 | 0.000 | 0.002 | 0.000 | 0.000 | 0.000 | 0.040 |
| DUK-IN | 0.000 | 0.000 | 0.000 | 0.009 | 0.000 | 0.000 | 0.000 | 0.142 |
| GRE | 0.000 | 0.000 | 0.000 | 0.002 | 0.000 | 0.000 | 0.000 | 0.041 |
| HE | 0.000 | 0.000 | 0.000 | 0.001 | 0.000 | 0.000 | 0.000 | 0.008 |
| IPL | 0.000 | 0.000 | 0.000 | 0.020 | 0.000 | 0.000 | 0.000 | 0.245 |
| MDU | 0.000 | 0.000 | 0.000 | 0.004 | 0.000 | 0.000 | 0.000 | 0.077 |
| MEC | 0.000 | 0.000 | 0.000 | 0.012 | 0.001 | 0.002 | 0.002 | 0.118 |
| MGE | 0.000 | 0.000 | 0.000 | 0.026 | 0.000 | 0.000 | 0.000 | 0.311 |
| MP | 0.000 | 0.000 | 0.000 | 0.031 | 0.000 | 0.000 | 0.000 | 0.353 |
| MPW | 0.000 | 0.000 | 0.000 | 0.001 | 0.000 | 0.000 | 0.000 | 0.021 |
| NIPS | 0.000 | 0.000 | 0.000 | 0.048 | 0.000 | 0.000 | 0.000 | 0.484 |
| NSP | 0.000 | 0.000 | 0.000 | 0.162 | 0.005 | 0.007 | 0.007 | 1.160 |
| OTP | 0.003 | 0.003 | 0.009 | 0.395 | 0.050 | 0.054 | 0.060 | 2.217 |
| SIGE | 0.000 | 0.000 | 0.000 | 0.227 | 0.012 | 0.015 | 0.015 | 1.480 |
| SIPC | 0.000 | 0.000 | 0.000 | 0.001 | 0.000 | 0.000 | 0.000 | 0.007 |
| SMP | 0.000 | 0.000 | 0.000 | 0.249 | 0.013 | 0.016 | 0.016 | 1.458 |
| UPPC | 0.000 | 0.000 | 0.000 | 0.286 | 0.015 | 0.019 | 0.019 | 1.627 |
| WEC | 0.000 | 0.000 | 0.000 | 0.144 | 0.012 | 0.014 | 0.014 | 0.904 |
| WPS | 0.001 | 0.001 | 0.003 | 0.506 | 0.038 | 0.045 | 0.047 | 2.374 |
| CLEC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| EES-ARK | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| EES-GSU | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| EES-LA | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| EES-MS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| EES-NO | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| EES-TX | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| LAFA | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.001 |
| LAGN | 0.000 | 0.000 | 0.000 | 0.001 | 0.000 | 0.000 | 0.000 | 0.002 |
| LEPA | 0.000 | 0.000 | 0.000 | 0.001 | 0.000 | 0.000 | 0.000 | 0.002 |
| SMEPA | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| **MISO RTO** | **0.004** | **0.004** | **0.013** | **0.638** | **0.076** | **0.084** | **0.093** | **3.013** |

[47] This is the LBA annual LOLE. A separate breakout for LBA LOLE during the third week of January (i.e. when the polar vortex is assumed to occur) can be found in the Polar Vortex Case Analysis Results section of the report.

[48] This is the LBA annual LOLE. A separate breakout for LBA LOLE during the third week of January (i.e. when the polar vortex is assumed to occur) can be found in the Polar Vortex Case Analysis Results section of the report.

## Appendix L. PJM Transmission Zone LOLE by Case

**Forecasted Loss of Load Expectation in PJM, by Scenario and Transmission Zone**

| PJM Transmission Zone | LOLE with Demand Response | | | | | LOLE without Demand Response | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Base Case | Nuclear Retirement Case | Polar Vortex Case[49] | High Load and Coal Retirement Case | | Base Case | Nuclear Retirement Case | Polar Vortex Case[50] | High Load and Coal Retirement Case |
| AECO | 0.000 | 0.000 | 0.000 | 0.000 | | 0.000 | 0.000 | 0.000 | 0.000 |
| AEP | 0.000 | 0.000 | 0.001 | 0.000 | | 0.000 | 0.000 | 0.001 | 0.000 |
| APS | 0.000 | 0.000 | 0.023 | 0.000 | | 0.000 | 0.000 | 0.023 | 0.000 |
| BGE | 0.000 | 0.000 | 0.074 | 0.000 | | 0.000 | 0.000 | 0.074 | 0.003 |
| ComEd | 0.000 | 0.000 | 0.089 | 0.017 | | 0.000 | 0.000 | 0.089 | 0.159 |
| DAY | 0.000 | 0.000 | 0.095 | 0.000 | | 0.000 | 0.000 | 0.095 | 0.007 |
| DOM | 0.000 | 0.000 | 0.076 | 0.000 | | 0.000 | 0.000 | 0.076 | 0.001 |
| DPL | 0.000 | 0.000 | 0.110 | 0.000 | | 0.000 | 0.000 | 0.110 | 0.003 |
| DUK-KY | 0.000 | 0.000 | 0.166 | 0.000 | | 0.000 | 0.000 | 0.166 | 0.032 |
| DUK-OH | 0.000 | 0.000 | 0.220 | 0.000 | | 0.000 | 0.000 | 0.220 | 0.086 |
| DUQ | 0.000 | 0.000 | 0.051 | 0.001 | | 0.000 | 0.000 | 0.051 | 0.104 |
| EKPC | 0.000 | 0.000 | 0.162 | 0.000 | | 0.000 | 0.000 | 0.162 | 0.001 |
| FE-ATSI | 0.000 | 0.000 | 0.421 | 0.004 | | 0.000 | 0.000 | 0.421 | 0.347 |
| JCPL | 0.000 | 0.000 | 0.572 | 0.018 | | 0.000 | 0.004 | 0.572 | 0.751 |
| METED | 0.000 | 0.000 | 0.171 | 0.002 | | 0.000 | 0.000 | 0.171 | 0.099 |
| PECO | 0.000 | 0.000 | 0.000 | 0.001 | | 0.000 | 0.000 | 0.000 | 0.025 |
| PENELEC | 0.000 | 0.000 | 0.000 | 0.000 | | 0.000 | 0.000 | 0.000 | 0.000 |
| PEPCO | 0.000 | 0.000 | 0.891 | 0.052 | | 0.003 | 0.021 | 0.891 | 1.509 |
| PPL | 0.000 | 0.000 | 0.043 | 0.000 | | 0.000 | 0.000 | 0.043 | 0.000 |
| PSEG | 0.000 | 0.000 | 0.065 | 0.046 | | 0.004 | 0.024 | 0.065 | 1.184 |
| RECO | 0.000 | 0.000 | 0.929 | 0.070 | | 0.006 | 0.031 | 0.929 | 1.758 |
| UGI | 0.000 | 0.000 | 0.841 | 0.046 | | 0.002 | 0.010 | 0.841 | 0.599 |
| **PJM RTO** | **0.000** | **0.000** | **0.939** | **0.086** | | **0.006** | **0.032** | **0.971** | **1.877** |

[49] This is the transmission zone annual LOLE. A separate breakout for transmission zone LOLE during the third week of January (i.e. when the polar vortex is assumed to occur) can be found in the Polar Vortex Case Analysis Results section of the report.

[50] This is the transmission zone annual LOLE. A separate breakout for transmission zone LOLE during the third week of January (i.e. when the polar vortex is assumed to occur) can be found in the Polar Vortex Case Analysis Results section of the report.

## Appendix M. Retirements and Export Uncertainty

Cases 1, 2, and 3 include a lower level of post-2016 retirements of coal-fired power plants than recent reports[51] have suggested may occur. It includes those retirements for which deactivation request have actually been submitted to the RTOs, as well as others that the IPA's consultants believe to be likely based on their market knowledge. Other possible retirements are considered to be more speculative, as in many cases they represent a view of how plant owners might respond to market conditions that have not yet occurred, and are thus not included in these cases.

One of the driving factors behind coal-fired power plant retirement forecasts has been the low level of energy revenues received by baseload coal and nuclear power plants. As natural gas prices have rebounded somewhat over their recent lows, it is possible that some additional coal plants may become economic to operate.

Furthermore, owners of possibly uneconomic coal-fired power plants may have operational or investment options, such as repowering or retrofitting, that have not yet been considered. In recent months, the owners of several plants whose impending retirements had been rumored (e.g., NRG's 732 MW coal-fired Avon Lake, 325 MW New Castle,1,326 MW coal-fired Joliet plants, 401 MW coal-fired Portland plant and 689 MW coal-fired Waukegan plant) have announced new plans to retain or repower capacity – these plants have been restored to the GE-MARS model.

As another example of the fluid nature of retirement forecasts, the IPA noted the following in its 2015 Procurement Plan:

> *"Based upon Schedule 3A data from NERC's Electricity Supply & Demand Database, MISO is projected to be short capacity supply to meet load plus target reserve margins for the delivery years 2014- 2019, with reserve margins averaging less than 10% during this period. This is approximately 4% below the 14.2% target reserve margin. However, on September 8, 2014, MISO released the third draft of the 2014 MISO Transmission Expansion Planning ("MTEP") report, which addresses resource adequacy. In this MISO report, reserve margins are projected to be on average higher than the Schedule 3A data. Relying on the draft MISO data, reserve margin in 2016 is only 0.2% below the target reserve margin."*

Some potential retirements, especially in MISO, may instead represent potential capacity exports. MISO in particular is subject to uncertainty around firm capacity exports. Generators can arrange several years in advance to export their capacity to support reliability in another RTO, because, in the case of PJM, they can be guaranteed a firm payment three years out; MISO cannot provide such firm payments more than a year in advance. For example, the Covert plant, located in Michigan, is physically located in the MISO footprint and will deliver its 1,100 MW of capacity to PJM. Dynegy, the owner of the former Ameren Illinois generators, has similarly

[51] NERC 2013 Long Term Resource Assessment (http://www.nerc.com/pa/rapa/ra/reliability assessments dl/2013_ltra_final.pdf). It indicated 8,615 MW of coal capacity reduction, and 1,346 MW of gas-fired capacity retired in MISO, all by 2016 (p. 52), and 10,276 of coal reduction in PJM, all by 2015 (p. 123). RFC (https://rfirst.org/reliability/Documents/RF 2014 Assessment-Long Term Resource.pdf ). It shows about 4,000 MW in PJM retirements by 2017 (p. 28) and 2,041 in MISO in 2016 (p. 30).

stated an interest in exporting its capacity to PJM. Capacity shortfalls due to such exports are not physical and have been described as “contractual and not a need for new power plants”.[52]

Some future coal plant retirement could be attributed to the pending enforcement of the EPA’s proposed Clean Power Plan (“CPP”)[53], which sets carbon emission targets by State, and other environmental regulations. Assuming there is no litigation in response to the proposed rule, the impact of the rule will not be felt until 2020 at the earliest, with full compliance required by 2030.

[52] Robert Walton, “MISO: Michigan will face 3,000 MW capacity shortfall in 2016,” *Utility Dive*, Oct. 23, 2014, quoting Platt’s.

[53] http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule.