

The Confluence of Power and Water: How Regulation of the Electric Power Grid Affects Water and Other Natural Resources

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October 2011

Introduction

Sometimes described as the world's largest machine¹, the U.S. electric power grid is a complex system of power plants, transmission and distribution lines, transformers and other electrical equipment responsible for delivering electricity to consumers 24 hours a day, 365 days a year. Three electric grids supply energy in the continental United States: the Eastern Interconnect, which includes most of the United States east of the Continental Divide; the Western Interconnect, in states west of the Continental Divide; and most of Texas (other than the Panhandle and some of eastern Texas). These three grids function and operate largely independent of each other.

The planning and operation of the power grid affects water and other natural resources in many different ways. Coal-fired power plants, for example, create air, water and land pollution. Fossil, nuclear and large solar power plants can use and consume enormous amounts of water. Hydropower and wind power plants can affect the environment through fish and bird kills. Coal mining and drilling for natural gas (including the increasingly popular use of fracking) and power plant waste disposal also impact the environment.²

For most of its history, the grid's basic design was based on the delivery of power from large utility-owned power plants to nearby consumers. Consumers generally did not concern themselves with the operation of the power grid, there was little or no competition, and utilities,

acting primarily under state laws, made nearly all of the decisions about where to build new plants and transmission lines in its service area.

Several major recent policy and technological developments have combined to change the grid's operational characteristics and the resulting environmental impacts. For example:

- Many states, especially in the Northeast and Midwest, restructured their electricity markets to encourage more competition and lower energy prices.³
- Utilities in the Northeast, Mid-Atlantic and Midwest formed regional wholesale energy markets known as regional transmission organizations (RTOs) intended to encourage utilities and others to improve grid reliability, more efficiently buy and sell power, and more thoughtfully and transparently plan long-term grid expansion.
- State renewable energy standards in the Midwest and elsewhere are spurring the development of wind power, especially in remote areas far from electrical load, which increases the need for new transmission lines to deliver the power to market.
- Several recent U.S. EPA standards will limit power plant air, water and other discharges and likely cause coal power plant owners to close many older plants rather than incur the substantial costs necessary to comply with the standards.

The Great Lakes region is at the epicenter of these changes. States are a mix of regulated and restructured retail electricity markets, and three different RTOs operate in the region. Wind power development is growing rapidly, fueled by state renewable electricity standards and other policies. State energy efficiency standards and other efficiency and “demand response” measures are reducing electric power demand. These and other factors – such as more stringent federal environmental regulation of fossil-fueled power plants and growing federal authority over grid planning and operation – are combining to affect the future of power supply and demand in the

Great Lakes region, and are creating new legal tensions among regulated and restructured states, wholesale energy markets, utilities and their customers.

I. Federal Regulation of Electric Power Systems Operation and Planning

A. The Federal Energy Regulatory Commission and the Federal Power Act

The Federal Energy Regulatory Commission (FERC) is the primary federal agency responsible for oversight of the electric power grid. FERC's authority derives from the Federal Power Act (FPA), 16 U.S.C. § 791-828c. Congress passed the FPA in 1920 with the primary objective of overseeing the development of hydroelectric dams.⁴ The first notable expansion of FERC's jurisdiction occurred in 1935, when Congress gave FERC authority to regulate most wholesale electric power sales in interstate commerce, while prohibiting FERC from regulating sales of *intrastate* commerce or power lines used exclusively over the local distribution of energy.⁵ The Act also governs a number of other activities not discussed here, including for example natural gas and oil pipeline rates and projects and approval of liquefied natural gas terminals.

Section 201(b)(1) of the FPA authorizes FERC to regulate “the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce,” including the transmission lines themselves, while precluding FERC jurisdiction over “facilities used in local distribution or only for the transmission of electric energy in intrastate commerce.” 16 U.S.C. § 824(b)(1).⁶ However, regardless of line size, states usually approve the specific siting and location of all new transmission and distribution lines.⁷

To some extent the physical characteristics of electricity align with the FPA's division of jurisdiction between the federal government and the states. Electricity is often transported over long distances across state lines through large transmission lines capable of carrying hundreds or

thousands of megawatts of power.⁸ Although it would be possible for each state to operate its own grid, that design would be costly and inefficient.

Electricity is usually delivered to the consumer via much smaller and less powerful distribution lines. These lines radiate out from transformer and substation networks connected to larger transmission lines. The physical laws of electricity prevent these small lines from carrying large amounts of electricity over long distances.

The FPA also regulates the electric power industry in other important ways, such as requiring that electric rates be “just and reasonable,” 16 U.S.C. § 824d(a), and authorizing FERC to reject proposed rates it finds to be “unjust, unreasonable, unduly discriminatory or preferential.” 16 U.S.C. § 824e(a). The Act also encourages the establishment of regional grid councils to ensure grid reliability, 16 U.S.C. § 824a(a), and empowers FERC to take other steps to foster long-term grid reliability. 16 U.S.C. 825a(b).

Increasing costs, reliability concerns, environmental regulation, changing policies and more demand for renewable energy have influenced federal regulation of the power grid. For example, more than 30 years ago, rising energy prices prompted Congress to pass the Public Utility Regulatory Policies Act (PURPA), which required utilities to purchase power from independent electricity producers at a price comparable to a utility’s cost to generate the same power (called the avoided cost).⁹ PURPA spurred the development of thousands of megawatts of smaller hydropower and combined heat and power projects, and it also demonstrated, importantly, that non-utility power projects could integrate successfully into the electric grid without serious operational problems.

Somewhat more recently, FERC began to exercise its jurisdictional muscle to influence and improve grid design, reliability and costs. In 1996, FERC issued the first of several orders to

encourage “open access” of the nation’s transmission system and reduce high power costs to ratepayers. Order 888, among the most significant of these orders, required public utilities to allow other power generation to access the utilities’ transmission lines, and to offer non-discriminatory tariffs for all users of the transmission system.¹⁰ FERC issued this “open access” order in part to complement state movement in direction of retail choice and restructured electricity markets.¹¹ FERC also made clear that it would not tolerate state efforts to frustrate open access, especially in non-retail choice states.¹² The Supreme Court subsequently rejected state assertions that Order 888’s limits on retail rates violated the Interstate Commerce Clause.¹³ Order 888, Order 890,¹⁴ and other FERC actions to encourage open and non-discriminatory access to utility-owned transmission systems facilitated the interconnection of non-utility owned wind power, combined heat and power, solar power, geothermal and hydroelectric power to the grid. At a more granular level, FERC has issued rules and approved RTO tariff changes that better integrate both renewable energy and demand-reducing measures into the grid and encourage regional and interregional long-term grid planning. FERC is taking these actions in part because of evolving state energy and environmental policies, especially in the Midwest/Great Lakes states, most of which have passed renewable electricity and energy efficiency standards in the last several years. FERC’s actions, in turn, will influence the energy mix and environmental impacts of electric power in the region.

In mid-2011 FERC issued an important rule on transmission planning and cost recovery for all RTOs and regulated utilities. Order 1000, the Transmission Planning and Cost Allocation rule, governs regional and inter-regional planning and allocation of costs for many transmission system upgrades.¹⁵ Among other important actions it requires all utilities and RTOs to consider enacted federal and state laws and regulations in long-term transmission planning. Importantly,

Order 1000 also requires consideration of non-transmission alternatives such as energy efficiency, storage and demand response “on a comparable basis,”¹⁶ although the order does not mandate selection of those solutions. Recognizing state fears of jurisdictional over-reaching, FERC made clear that the regional planning process “is not the vehicle by which integrated resource planning (IRP) is conducted”; IRP remains under state purview.¹⁷ In the proposed Order 1000 rule, FERC explained how policies could affect transmission expansion:

[S]tate policies to promote increased reliance on renewable energy resources, such as the renewable portfolio standard measures discussed above, accentuate the need for transmission to deliver electricity from location-constrained renewable energy resources to load centers. Other state policies, such as goals for use of energy efficiency or demand response, may lower load forecasts within a given load zone and thereby affect transmission planning determinations.¹⁸

Equally significant, Order 1000 requires that the costs of transmission system upgrades be paid by all customers throughout the region who benefits. While stating that Order 1000 did *not* authorize regional cost recovery for non-transmission alternatives,¹⁹ FERC did not determine that such cost recovery would violate the FPA.

Another FERC proposal would better integrate wind energy resources into grid operations.²⁰ This rule should reduce the instances when wind power is curtailed on the system, which in turn would impact the amount of other generation needed to supply load. Yet another FERC rule will increase the compensation that RTOs pay for customers to reduce or shift their demand for electricity. This rule requires RTOs to pay “demand response” the full wholesale price for energy, comparable to generation resources.²¹

Taken together, FERC’s planning, wind integration and demand response rules will affect the mix of generation and demand response resources on the grid. Less restrictive transmission planning and cost allocation rules are likely to spur the development of more wind power generation and the use of less fossil-fueled power throughout the Midwest, and more quickly,

than otherwise would occur. More energy efficiency and demand response also could reduce fossil and nuclear generation throughout the region. In any event, the recent FERC actions confirm that federal and state energy policies often require FERC support to be successful.

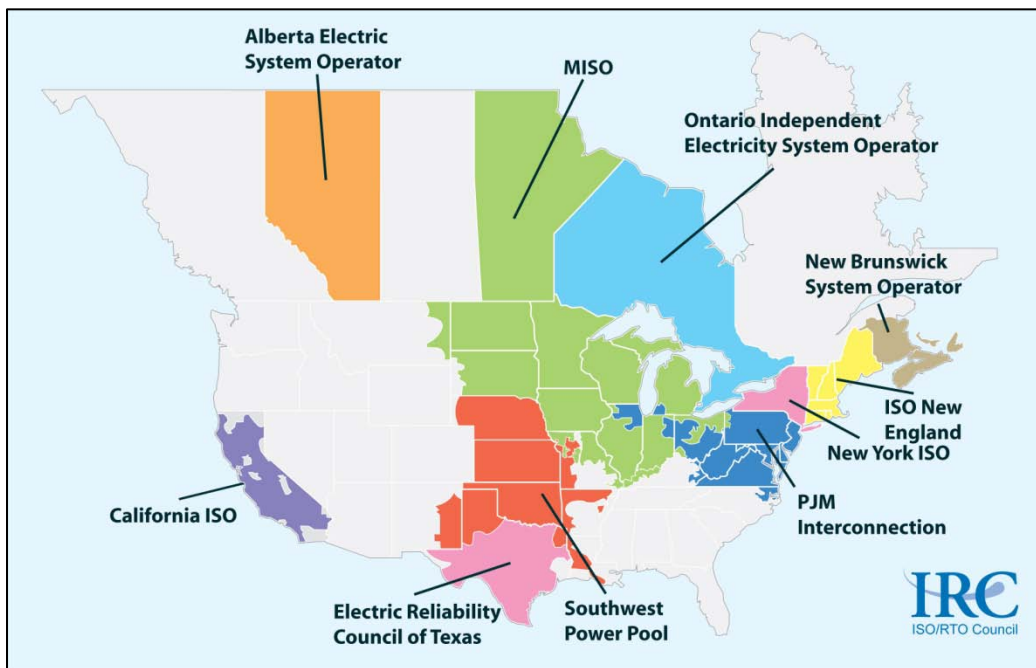
B. Regional Transmission Organizations and Independent System Operators

Concurrent with its open access rules and other changes, and also concurrent with state moves towards retail choice and “restructured” electric markets, FERC encouraged utilities to join RTOs. In Order 2000, issued in 1999²², FERC encouraged but did not mandate that utilities join RTOs. FERC believed that the RTOs were superior to utility-by-utility decisions in managing and planning the power grid, reducing economic and other barriers to buying and selling power across longer distances, and engaging more consumer and stakeholder participation in grid planning and operations. While the FPA had long authorized FERC to authorize the creation of regional power councils,²³ Order 2000 represented a new FERC boldness to regionalize electric grid operations, planning and markets.

RTOs are a close relative of independent system operators (ISOs), except that RTOs are always regional in scope, while ISOs may be either state or regional.²⁴ Apart from regional character, which is unique to RTOs, the two types of organizations share three defining characteristics: independence, operational authority and short-term reliability.²⁵ In addition to meeting these minimum characteristics, RTOs must perform eight functions:

1. Energy markets tariff administration and design;
2. Manage congestion;
3. Electricity parallel path flow;
4. Ancillary services;
5. Open access same-time information system, total and available transmission capacity;
6. Market monitoring;
7. Planning and expansion;
8. Interregional coordination.

Three RTOs and ISOs operate in the Great Lakes region in the United States: Midwest ISO or MISO (which is an RTO despite its name), PJM Interconnection, and New York ISO. The Ontario Independent Electricity System Operator manages transmission grid operations in Canadian territory contiguous to the Great Lakes.²⁶ While the Midwest ISO and PJM are contiguous, their boundaries cross through several states, including Illinois, Michigan, Indiana and Ohio. RTO boundaries are not permanent; transmission-owning utilities can voluntarily enter, exit, or move between RTOs. As reflected in the map below, the absence of RTOs is notable in the South, where no state has fully restructured, and the West, where public power is strong.²⁷



Of the nine RTO functions, two of them – congestion management and system planning – arguably most influence the transmission system’s environmental effects in the Great Lakes region. Congestion management generally refers to the RTO’s system of balancing power supply with consumer demand through day ahead and real-time energy markets. Congestion management occurs over the short term, ranging from minutes to months. Longer-term

transmission system planning and expansion involves changes to the grid's system of wires, transformers, other electrical equipment and infrastructure (and in some cases power plants) to satisfy grid reliability needs, meet consumer demand and satisfy relevant public policy requirements.

The three RTOs/ISOs in the Great Lakes region operate functionally similar energy markets. In these markets, the day-ahead auction market largely establishes energy supply and customer demand needs for the following day. All of the supplier offers are stacked each hour of the day in order of cost. The hour's clearing price is set at the prices of the lowest marginal cost resource necessary to meet the hour's total energy demand (load). The entire day-ahead market is cleared hourly, and *all* generators are paid the market clearing price regardless of their actual cost to run. The hourly clearing prices are called locational marginal prices (LMPs), and typically differ in different regions within each system because of transmission constraints and other factors.

The following day, in the real-time market, the RTO dispatches sufficient energy each hour (and at small increments within each hour) to meet customer demand, moving up the dispatch stack starting with the least costly power needed to meet demand. Each RTO has procedures in place to ensure sufficient energy is dispatched to meet real-time, security-constrained operating conditions.²⁸

Full integration of renewable energy and demand-side measures into the RTO energy markets generally reduces total emissions and other environmental consequences of power generation. There are three distinct ways that fossil-fuel generation is curtailed:

First, as wind and solar energy generation become more widespread, they generally will be price-takers in the daily energy market; they will bid at zero or near-zero whenever they

generate power and be paid the prevailing clearing price. In these situations, wind and solar will displace more expensive generation on the margin. During peak hours, this is likely to be gas-fired generation or expensive coal-fired generation. During off-peak hours, the generation is most likely to be mid-merit or even baseload coal-fired generation. If storage mechanisms are available, the renewable resources are more likely to be dispatched during more expensive hours, and their bids are unlikely to be zero (the cost of storage will need to be reflected in their offers). The exact impact on emissions will depend on the resource mix in the particular RTO and the hours in which the renewable resources are offered.

Second, energy efficiency resources from demand-side management programs will lower energy consumption in all hours. Whatever resource is on the margin (highest priced) in that hour will be displaced; for off-peak hours this is most likely coal-fired generation and for on-peak hours it could be gas-fired or coal-fired generation.

Third, the participation of demand response resources in the energy market will mostly occur during high-priced on-peak hours. The demand response resources will displace the most costly units in the bid stack. Each RTO has a different emissions profile for the top 1-2% of peak demand hours in each year; analyzing that profile (that likely includes expensive and more-polluting peaking units) will provide a means to quantify the emission reductions from demand response resources.

Long-term system planning is another core RTO function, and each RTO approaches planning somewhat differently. For example, MISO engages in a 10-20 year forward-looking planning process every 18-months. The end-product is a MISO Board-approved expansion plan listing each new transmission system project approved in the RTO. Approved projects are funded through MISO-imposed fees on all users that benefit from the upgrades. The MISO planning

process includes accounting of current and potential future public policies, and much of MISO's planning process has evolved in response to the many wind power projects being constructed in the region and the resulting need to deliver the wind power to load centers (usually cities and other high-demand areas). Some aspects of MISO's planning process are similar to those now required by FERC Order 1000.

C. North American Electric Reliability Corporation and Electric Reliability Organizations

While RTOs, ISOs, utilities and other grid operators throughout the country are responsible for planning and managing the electric grid, the North American Electric Reliability Corporation (NERC) establishes and enforces the grid's technical reliability and resource adequacy standards.²⁹ For example, NERC requires grid operators to plan and manage the grid such that it can absorb sequential loss of generation or transmission facilities without blackouts, and NERC defines the precise circumstances ("contingencies") under which this could occur.³⁰ These FERC-approved standards are the minimum standards for users to meet on the operating grid. NERC works in part through its eight regional electric reliability organizations³¹ and with electric utilities and other market participants.

To help meet its mission of maintaining electric grid reliability, NERC periodically evaluates potential regulatory and legal impacts on grid operations. In 2010 NERC evaluated the impacts of several major new U.S. EPA air, water and solid waste regulations on power plant operations. NERC's analysis concluded that these regulations could force the retirement or early retrofits of up to 19 percent of the country's coal, gas and oil power plants (76,000 megawatts).³² Of the four regulations studied, the Clean Water Act Section 316(b) rules (not yet in force) would have the most impacts, resulting in up to 36,000 MW of plant retirements.³³ The Section 316(b) regulations could require power plants that currently use once-through cooling water

systems (and draw millions of gallons daily of water from rivers and streams) to instead use recirculating water systems. Since the conversion process is costly, the owners of many older plants may choose to retire them instead of complying with the new rules. NERC's study was somewhat speculative because U.S. EPA had not yet proposed new Section 316(b) regulations. In March 2011 U.S. EPA proposed the regulations, and many believe they may not be as costly to comply with as NERC believed in 2010.

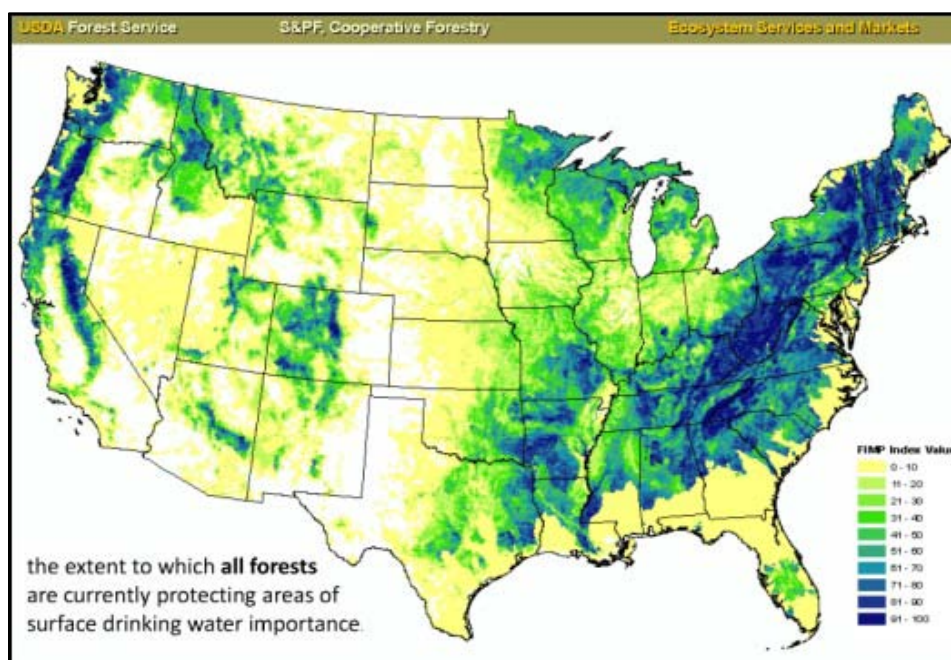
Throughout 2011 both PJM and MISO performed their own studies of the impact of the new EPA standards, and they came to somewhat different results. MISO's estimate (still in draft form) estimated that about 3,000 MW of capacity are at risk for retirements.³⁴ PJM estimates that 11,000 MW are "most at-risk" and additional 14,100 MW are at "some risk" for retirement.³⁵ NYISO also is conducting a similar study.

D. U.S. Department of Energy/Eastern Interconnection Planning Collaborative

The 2009 American Recovery and Reinvestment Act authorized the U.S. Department of Energy (DOE) to convene grid stakeholders in the three interconnects to assess their long-term demand and transmission requirements.³⁶ In the Eastern Interconnect, a stakeholder collaborative organized by the RTOs and utilities in the non-RTO areas is now in a three year process to evaluate current and future transmission system needs based on several potential different "energy futures."³⁷ This Eastern Interconnection Planning Collaborative (EIPC) will select three futures for detailed study and then examine the potential transmission build-out necessary to achieve each future.³⁸ The EIPC's modeling activities over the next year should generate data on some of the environmental impacts of the different futures.

The Eastern Interconnection States Planning Council (EISPC) is working on a related DOE-funded project intended to identify major energy zones throughout the Eastern

Interconnect.³⁹ The primary goals of this project are to identify areas in the Eastern Interconnect with resources conducive to developing clean energy/low carbon generation, and provide early identification of generation siting issues.⁴⁰ This process likely will generate GIS-based map layers of different datasets, including water quality, which is an important ecosystem service. For example, the map below (created by the U.S. Forest Service) identifies the extent to which forests serve to protect surface drinking water sources.⁴¹



This type of mapping, especially at a more granular level, will help to identify potential issues for siting transmission and generation earlier in the planning process. Monetization of water resource and other impacts also could provide inputs into the benefit-cost analysis for new line developments.

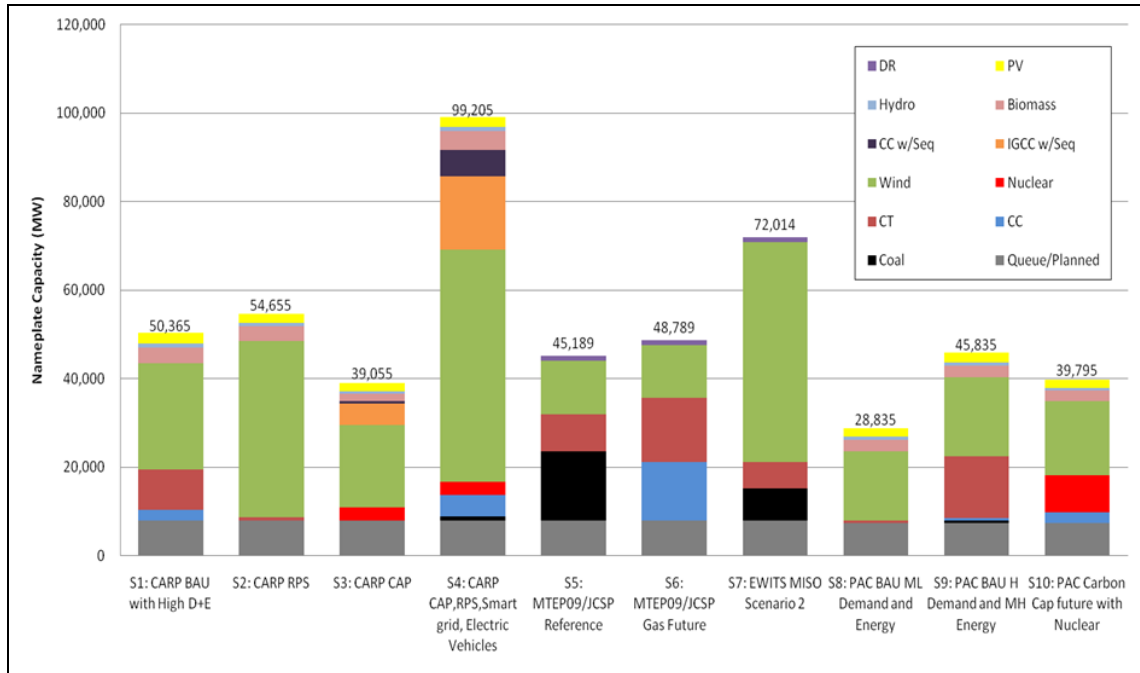
E. Gaps and Potential Opportunities for Improvement Relating to Water Resource Use

A range of opportunities exist for these federally-authorized entities – especially FERC and the RTOs in the Great Lakes region – to influence water resource use. They include:

1. RTOs should ensure that they evaluate all relevant laws and regulations in their long-term planning process, including water regulations. Order 1000 now requires consideration of these standards, but the devil is in the details. For example, while MISO is taking state renewable energy standards into account in its long-term planning, other state and federal policies also are relevant to long-term planning and need to be considered.

2. Commissioners and FERC policy staff need more education about the relationship between energy and water use in the Great Lakes watershed. FERC currently is very involved in understanding the reliability impacts of new EPA regulatory standards; similar education would be appropriate to help Commissioners and staff understand the environmental impacts of all generation.

3. Since no RTO in the Great Lakes region currently estimates the direct water impacts of power generation in their system, RTO stakeholders could request that the RTO estimate these impacts. That information could then be factored into the RTO's long-term transmission and generation planning as a policy consideration, and also be used by state and federal policymakers to help shape new environmental/water policies. As shown in the chart below from a recent MISO modeling exercise, different possible energy futures will lead to very different generation mixes, which in turn will have different environmental and water use impacts.⁴²



4. RTOs also could perform “low water consumption” sensitivity analyses in every future to help assess the effects of low water consumption policies across every future scenario. In any case, RTOs are well-positioned to educate state utility commissions and other stakeholders about the water and other natural resource impacts of different types of power generation.

5. Environmentally preferable transmission siting and energy dispatch could significantly reduce water and other environmental impacts of generation. Although such options raise some legal, policy and technical questions, they should be addressed sooner rather than later.

6. RTOs should integrate environmental impacts earlier in the transmission planning process. RTOs do not generally account for environmental costs and considerations in planning new transmission lines, other than some limited estimates of air/carbon emissions from different expansion scenarios. With sufficient data on the monetization of environmental benefits and

ecosystem services they could, for example, include these costs in the overall benefits-costs calculations for new transmission lines.

II. State Markets and Utility System Planning

As noted above, the Interstate Commerce Clause and the Federal Power Act limit FERC's authority over state distribution networks and retail electricity.⁴³ State utility commissions regulate such matters as retail power rates, mergers and acquisitions within their states, siting of transmission and generation facilities, and related utility matters.⁴⁴ However, no discussion of state regulation and oversight of the electric power industry can occur without addressing "restructuring," which has fundamentally changed state oversight of the electric power industry.

Beginning in the late 1990s, a wave of state utility restructuring occurred in many states. Having seen telephone rates fall after deregulation and the advent of competition in the telecommunications industry, many states believed that similar savings were possible in the electric utility industry. These states believed that encouraging competition, especially in the power generation market, would reduce utility expenses and consumer costs. A consequence of restructuring relevant to this report is that state utility commissions in restructured states often have less direct control and fewer supervisory powers over the utilities and independent power producers in their states. Consequently, in these states there may be fewer opportunities for state commissions to influence the impact of power generation on water resources in their states.

A. Regulated Energy Markets

Three states in the Great Lakes region, Indiana, Minnesota and Wisconsin, currently control electricity generation and distribution through regulated energy markets. In these states, utility commissions regulate the retail rates of the electrical industry as a natural monopoly.⁴⁵

Vertically integrated utilities own the generation, transmission, and distribution facilities and provide power to customers within their service area. State commissions set the regulated utilities' retail rates and encourage what the commissions perceive to be best practices for electric system operation, such as generation diversification and other attributes of integrated resource planning IRP.⁴⁶ Utilities that practice IRP consider the full evaluation of alternatives, including energy efficiency and renewable energy resources, to provide cost-effective and reliable service.⁴⁷ Of all of the states in the Great Lakes region, only Indiana and Minnesota have fulsome IRP rules.⁴⁸ Regardless of whether IRP exists, in all regulated states the electricity market is relatively static – rates are somewhat stable and match a utility's costs, state policymakers and utilities plan generation and transmission expansion, and new electric companies generally do not compete in the market.

The traditional regulatory approach has been criticized for its market inefficiencies,⁴⁹ and rates can increase beyond what are judged to be acceptable levels. Minnesota is trying a new approach to maintain rate control and reduce capital costs.⁵⁰ This “special recovery mechanism” is supposed to achieve this goal in part by assessing additional fees to customers. Neither the Minnesota Public Utilities Commission (MPUC) nor the utilities have conducted any research to measure the impact of this new method.⁵¹

B. Restructured Energy Markets

Five states in the Great Lakes region currently operate with restructured energy markets: Illinois, Michigan (more accurately described as “partially restructured because of state law limits on the extent of deregulation), New York, Ohio, and Pennsylvania. Restructured energy markets are intended to encourage competition in the electric power industry and allow consumers to choose their electricity suppliers at the retail level. As noted above, the success of

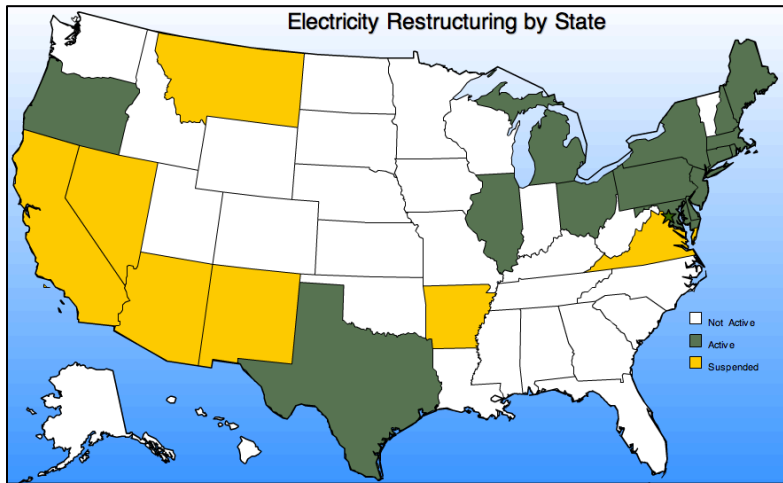
the Public Utility Regulatory Policies Act of 1978, showed that competition in the energy markets was possible, at least at the wholesale level, by requiring utilities to purchase power from specific kinds of generators, albeit at a defined “avoided cost.” These generators could compete for the utilities’ dollars and potentially reduce ratepayer costs.⁵²

In the mid-1990s, several states with high retail rates began to experiment with restructuring their retail electricity markets. The goal was to provide consumers with more choices in the electricity market by sparking competition among electricity providers.⁵³ Policymakers believed that a more competitive electricity market could lower rates, provide better service, spur innovation, and encourage development of clean sources of power.⁵⁴

Restructuring has had decidedly mixed results. In theory, competition among suppliers would result in lower rates,⁵⁵ along with allowing customers to purchase renewable energy and to consider customer service as a decision factor among different suppliers. In reality, many consumers have been unwilling to leave their utility electricity provider. For example, as of 2006 (the last year for which this comparative data is available), the percentage of customers shopping for lower rates from suppliers other than their utility ranged from 7-19% in Massachusetts, New York, and Ohio,⁵⁶ and many states have had levels five percent.⁵⁷ On the other hand, as of 2009, non-utility suppliers serve more than 50% of the retail load in Illinois, up from 18% in 2005.⁵⁸

Nor have retail rates dropped as hoped. Rates did initially decrease at a faster pace in restructured rather than regulated markets. However, this decrease was linked more to state-mandated rate reductions than to increased competition among suppliers.⁵⁹ Rates began to increase once those mandated reductions expired. For example in 2003, rates increased 19% in New Jersey when rate caps expired.⁶⁰ In 2007, Illinois customers saw rate increases of 45% and higher when a ten-year rate cap expired, prompting a law that included a \$1 billion rate relief

program and the promotion of renewable energy.⁶¹ Rate increases have played a role in the rolling back of restructured programs in Arizona, Arkansas, California, Montana, Nevada, New Mexico, and Virginia.⁶² The map below shows the current status of restructuring in the United States as of 2011.⁶³



C. Public Power and Cooperatives

Cooperatives are consumer-owned electric power providers, and usually but not always exist in rural areas. Public power providers are owned and operated by units of government. In most cases these energy providers are largely exempt from state utility commission regulation. Collectively they generate approximately 15% of all power in the Great Lakes states.⁶⁴

D. Analysis – Gaps and Opportunities for Improvement Relating to Water Resources

State utility commissioners generally do not consult with state environmental agencies early in the transmission siting and other energy planning processes. Utility commissions in the Great Lakes region have not prioritized electric power water use, consumption and even water quality as issues for review, except to some extent in the context of siting. Authorizing statutes

for the commissions generally do not target environmental quality in general or water issues in particular as among their responsibilities. These issues generally are left for state environmental agencies to consider in the context of permitting and other regulatory approvals. State environmental authorities, however, rarely consider the complete universe of power generation or the relationship between generation and water issues.

The public utility commissions in several states in the Great Lakes region do have some statutory latitude to consider the environment in their decisions. The Illinois Public Utilities Act, for example, establishes environmental quality as a goal of the state commission's regulatory powers, and requires the consideration of the environmental costs of proposed actions with "significant" environmental impacts in applicable regulatory processes. 220 ILCS 5/1-102(b)(1). Michigan and Illinois also have environmental disclosure statutes requiring utilities to periodically disclose electricity generation sources and certain pollutants associated with each resource. *Id.* 5/16-127; Mich. Comp. Laws Ann. 460.10r(3). Neither state requires reporting on water impacts.

In some states energy planning is required to consider environmental impacts. For example, Minnesota's "environmental externalities" statute requires the MPUC to quantify the environmental costs associated with different forms of power generation and use that data when evaluating and selecting resource options in utility resource plan and certificate of need proceedings. Minn. Stat. 216B.2422, subd. 3(a). To date, the MPUC has established values (in \$/ton of air pollutant) for each of the criteria pollutants and carbon dioxide.⁶⁵ The MPUC has not considered establishing water quality or quantity values.

Minnesota's environmental externalities statute is the rule, rather than the exception, in the Great Lakes region. To the extent that states address water and other environmental issues

associated with power plants, they do so through federal and state environmental legislation and environmental agencies. For example, as discussed earlier, Section 316(b) of the Federal Water Pollution Control Act requires the U.S. EPA to establish standards for cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. (Section 316(b) does not set levels of consumptive water use.) Cooling water intake structures can pull fish and shellfish or their eggs into a power plant's or factory's cooling system (“entrainment”). There, the organisms may be killed or injured by heat, physical stress, or by chemicals used to clean the cooling system. Larger organisms may be killed or injured when they are trapped against screens (“impinged”) at the front of an intake structure.⁶⁶

State commissions rarely consider information such as intake structure impacts on aquatic life when evaluating certificate of need requests or in other proceedings. Those issues usually are within the scope of federal and state environmental authorities.

To address these gaps, several actions could help state utility commissions give greater consideration of water resource impacts in the planning process. First, to sensitize state commissions as to the issues and promote more coordination among different state agencies, stakeholders could:

1. Prepare state-specific and regional reports and fact sheets for utility commissions based on the Phase I Great Lakes Energy-Water Nexus Initiative and other work.
2. Convene joint meetings of state environmental, natural resources and utility commission staff to report on commission findings.

Second, existing laws and standards may be insufficient to adequately consider water impacts. Laws could require commissions to:

1. Study the direct water quantity and quality impacts of all existing power generation in the state.
2. Periodically evaluate the “indirect” impacts of power plants on water quality and quantity, such as through thermal generation cooling, fracking of natural gas deposits, mine discharges, and discharges from waste lagoons, scrubbers, and other on-plant operations.
3. Evaluate the environmental costs of water consumption and use by power plants, similar to Minnesota’s environmental externalities rule.
4. Require utilities to assess water issues in their integrated resource planning process (in regulated states).
5. Incorporate water quantity and quality impacts in power plant siting proposals.
6. Require utility and non-utility reporting and public disclosure of water use and consumption for each utility and non-utility power provider. Several states already require on-bill disclosures of utilities’ power sources by generation type (for example, Illinois); this would be an extension of that type of reporting obligation.

Several of these proposals likely would involve “silo-busting” between the state environmental/natural resource agencies and the public utility commissions. Compounding the challenge is that the commissions operate with more independence than state agencies that report directly to the governor.

Like many other environmental issues, water use and quality issues reach beyond any one state’s borders.⁶⁷ State commissions can work through national and regional associations to evaluate water issues associated with energy production. Midwestern state commissioners are members of the Mid-America Regulatory Conference (MARC) and its national affiliate the National Association of Regulatory Utility Commissioners (NARUC). MARC, NARUC and

other regional commissioner groups serve as important forums for state commissioners and their staffs to stay abreast of the important energy regulatory and related issues. Energy-related water issues could be a focus of discussion and study for these organizations, and could help to develop more consistency among the standards in different states relating to water quality.

Conclusion

The high-power electric grid does not just “happen.” Much like transportation systems, the specific choices made in modern grid planning and operations can profoundly influence the grid’s environmental impacts. FERC’s recent rulemakings such as in Order 1000 provide new and more assertive guidance and authority for grid planners to consider a range of both transmission and non-wires solutions to energy problems. State utility commissions have significant authority to influence grid planning at the local level and to better integrate the distribution grid with the FERC-regulated high-power grid. In both federal and state forums, grid planning and operations can be more active and influential than passive and reactionary on matters related to water and other environmental concerns.

Endnotes

1 David Biello, *The Start-Up Pains of a Smarter Electricity Grid* (Scientific American, May 10, 2010). <http://www.scientificamerican.com/article.cfm?id=start-up-pains-of-smart-grid>.

2 See, for example, Erik Mielke et al., *Water Consumption of Energy Resource Extraction, Processing and Conversion* (Harvard Kennedy School, 2010).

3 Many states that restructured their markets believed that the apparent success of deregulation in the telecommunications industry in lowering prices also would occur in the electric power industry.

4 Glenda K. Harnad and Thomas Muskus, Powers of Federal Energy Regulatory Commission, *Corpus Juris Secundum: Electricity* (2010).

5 *Federal Power Comm'n v. Southern California Edison Co.*, 376 U.S. 205, 210 (1964). The Federal Power Commission was reorganized and renamed FERC in the DOE Organization Act of 1977, Pub. L. 95-91.

6 FERC created a seven factor test to help distinguish federal and state jurisdiction of different lines. The factors are: (1) Local distribution facilities are normally in close proximity to retail customers; (2) Local distribution facilities are primarily radial in character; (3) Power flows into local distribution systems; it rarely, if ever, flows out; (4) When power enters a local distribution system, it is not reconsigned or transported on to some other market; (5) Power entering a local distribution system is consumed in a comparatively restricted geographical area; (6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system; and (7) Local distribution systems will be of reduced voltage. See *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶¶ 31,036, 31,771 (1996). In practice, most lines 69 kilovolts (kV) and larger are subject to FERC jurisdiction. See *Public Service Electric and Gas Company*, 122 FERC ¶61,234 (2008).

7 Electric power lines that cross through federal lands (for example, parks, wildlife refuges, national forests) trigger federal review under the National Environmental Policy Act, 42 U.S.C. §§ 4321 et seq.

8 As noted earlier, most of Texas is within a single electric grid (Electric Reliability Council of Texas) and is not subject to federal jurisdiction.

9 Pub. L. 95-617 (1978); codified in part at 16 U.S.C. § 824a-3.

10 FERC Order 888. FERC stated that “it is our statutory obligation under sections 205 and 206 of the Federal Power Act (FPA) to remedy undue discrimination. To do so, we must eliminate the remaining patchwork of closed and open jurisdictional transmission systems and ensure that all these systems, including those that already provide some form of open access, cannot use monopoly power over transmission to unduly discriminate against others.” Order 888, 3-4.

11 *Ibid.* at 2.

12 For example, “[f]urther, the Commission intends to be respectful of state objectives so long as they do not balkanize interstate transmission of power or conflict with our interstate open access policies.” *Ibid.* at 442.

13 *New York v. FERC*, 535 U.S. 1 (2002).

14 *Preventing Undue Discrimination and Preference in Transmission Service*, FERC Stats. & Regs. ¶ 31,241 (2007) (Order 890). Order 890 mandated coordinated and transparent transmission planning, consistent measurement of available transmission capacity on power lines, and took other steps to strengthen Order 888’s open access provisions.

15 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶61,051 (July 21, 2011) (Order 1000).

16 *Ibid.* ¶148.

17 *Ibid.* ¶154.

18, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 131 FERC ¶ 61,253 (June 17, 2010), ¶36.

19 Order 1000, ¶779.

20 *Integration of Variable Energy Resources*, 133 FERC ¶ 61,149 (2010).

21 *Demand Response Compensation in Organized Wholesale Energy Markets*, 134 FERC ¶ 61,187 (March 15, 2011) (Order 745).

22 *Regional Transmission Organizations*, FERC ¶ 61,285 (1999) (Order 2000).

23 Section 202 of the Federal Power Act authorizes FERC to “divide the country into regions for the purpose of voluntary coordination of facilities for the generation, and sale of electric energy.” 16 U.S.C. § 824a(a). Congress passed this section of the FPA in 1920.

24 Order 2000, 257 (“we conclude that a large scope is important for an RTO to effectively perform its required functions and to support efficient and nondiscriminatory power markets.”).

25 Order 2000.

26 <http://www.ferc.gov/industries/electric/indus-act/rto.asp>.

27 Map used with permission of ISO/RTO Council.

28 See generally Larry Schedin and Kavita Maini, *How the Midwest Independent System Operator Day 2 Market Works* (November 2007). <http://renewables.morris.umn.edu/wind/conferences/2007/Schedin-TheSecondDayMISOMarketHandout.pdf>.

29 NERC is a non-profit corporation, and is the successor to the North American Electric Reliability Council.

30 NERC Standard Standard TPL-001-0.1. http://www.nerc.com/files/TPL-001-0_1.pdf.

31 See NERC, *Compliance: Regional Programs* (providing full list of regional reliability organizations). <http://www.nerc.com/page.php?cid=3|23>.

32 NERC, *Potential Resource Adequacy Impacts of U.S. Environmental Regulations* (Oct. 26, 2010), VI (addition of derated and retired units by 2018 under “Strict Case”).
<http://www.nerc.com/page.php?cid=3|23>.

33 Ibid. at IV.

34 Midwest ISO, *EPA Impact Analysis: Impacts from the EPA Regulations on MISO* (2011).
<https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2011/20110824/20110824%20PAC%20EPA%20Report%20Draft%2020110812.pdf>.

35 PJM, *Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants*. <http://www.pjm.com/about-pjm/newsroom/newsletter-notices/state-lines/2011/~media/documents/reports/20110826-coal-capacity-at-risk-for-retirement.ashx>.

36 Pub. L. 111-5, 123 Stat. 115, 139 (2009).

37 For example, a future that assumes a price on carbon emissions, or a future that assumes policy choices emphasizing a particular generation technology.

38 See generally www.eipconline.com for information about the EIPC.

39 See generally <http://communities.nrri.org/web/eispc/community-home-and-charter> for information about the EISPC.

40 See <http://communities.nrri.org/web/eispc/community-home-and-charter> for more information on EISPC.

41 Albert Todd and Emily Weidner, *From Forest to Faucet: Drinking Water as an Ecosystem Service* (U.S. Forest Service (undated presentation), slide 16. <http://conference.ifas.ufl.edu/aces/Presentations/Tuesday/Plenary%20D-G/pm/Yes/0430%20A%20Todd.pdf>.

42 Midwest ISO, *2010 Transmission Expansion Plan* (2010), 145. <https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlan2010.aspx>.

43 16 U.S.C. § 824(b)(1).

44 See Scott Hempling, “Economic Regulatory Jurisdiction in the U.S. Electric Industry,” *The Electric Industry at a Glance* (NRRI, 2008), 30. http://www.nrri.org/pubs/electricity/electricity_at_a_glance.pdf.

45 Fred Bosselman, Jim Rossi and Jacqueline Weaver, *Retail Competition in Electric Power, Energy, Economics and the Environment: Cases and Materials* (Foundation Press 2d ed. 2006), 907.

46 See National Council of Electricity Policy, *A Comprehensive View of U.S. Electric Restructuring with Policy Options for the Future* (2003), 17 (Comprehensive Electric Restructuring)(noting that restructured markets do not have the same level of diversified generation). <http://www.hks.harvard.edu/hepg/Papers/BrownSedano.pdf>.

47 See Energy Policy Act of 1992, § 111(d)(19) (definition of integrated resource planning).

48 Rachel Wilson and Paul Peterson, *A Brief Survey of State Integrated Resource Planning Rules and Requirements* (Synapse Energy Economics, Inc., April 2011), 5.

49 See Harry M. Trebing, “A Critical Assessment of Electricity and Natural Gas Deregulation,” *Journal of Economic Issues* (June 2008)(Critical Assessment).

50 Minnesota Public Utilities Commission, *Utility Rates Study* (2010), 12 (noting state public policy requirements and federal policy requirements for more integration have stressed Minnesota utilities).

51 Ibid.

52 See Christopher G. Bond, Shedding New Light on the Economics of Electric Restructuring: Are Retail Markets for Electricity the Answer to Rising Energy Costs? 33 *Conn. L. Rev.* 1311, 1317-18 (2001).

53 See The Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy* (2006), 87 (“The idea was that customers could obtain electric service at lower prices if they could choose among suppliers.”).

54 See National Council of Electricity Policy, *Comprehensive Electric Restructuring*, 2-5.

55 For criticisms of the economics behind restructured energy markets, see Trebing, “Critical Assessment”.

56 William Steinhurst, *The Electric Industry at a Glance* (NRRI 2008), 22 (2008).
http://nrri.org/pubs/electricity/electricity_at_a_glance.pdf.

57 Ibid.

58 Illinois Commerce Commission, *Retail and Wholesale Competition in the Illinois Electric Industry: Fourth Triennial Report* (2009), 17.

59 See Tony Dutzik et al., *Toward A Consumer-Oriented Electric System: Assuring Affordability, Reliability, Accountability and Balance After a Decade of Restructuring* (Natl. Assoc. of State PIRGs, 2004), 7. <http://cdn.publicinterestnetwork.org/assets/2c4514101b97ebf374e1b0db2577d18f/US-Towards-a-Consumer-Oriented-Electric-System.pdf>.

60 Connecticut Office of Legislative Research, *Electric Restructuring-Rationale and Results in Other States* (August 28, 2006). <http://www.cga.ct.gov/2006/rpt/2006-R-0526.htm>.

61 K&L Gates, *Government-Brokered Rate Relief Encourages Sustainable Energy Development* (September 2007). <http://www.klgates.com/newsstand/detail.aspx?publication=5577>.

62 U.S. Energy Information Administration, *Status of Electricity Restructuring by State* (September 2010). http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html.

63 Ibid.

64 Environmental Law and Policy Center analysis of 2009 Energy Information Administration data. States include Illinois, Indiana, Michigan, Minnesota, Ohio and Wisconsin.

65 <http://www.puc.state.mn.us/puc/electricity/documents/reports-studies/012115>.

66 For example, FirstEnergy reports that its Bay Shore power plant, located on the Maumee River near Toledo, Ohio, impinges 46,000,000 fish per year (majority die), and entrains hundreds

of millions of fish larvae and eggs. Kinectrics, *Bay Shore Power Plant Cooling Water Intake Structure Information and Sampling Data* (January, 2008), 11-31. http://www.epa.state.oh.us/portals/35/permits/bayshore_IE_data_collection.pdf.

67 As Chairperson Daniel Ebert noted in a concurrence for the Wisconsin Public Service Commission, “the ability of one state to pursue an integrated resource planning process on its own and to implement specific policy goals on its own is no longer realistic or desirable.” Wisconsin Public Service Commission, Order, Docket No. 6690-CE-194 (May 23, 2008) (Chairperson Daniel Ebert concurring).