

Addressing the Effects of Environmental Regulations: Market Factors, Integrated Analyses, and Administrative Processes

Introduction

As state commissions consider how best to respond to new and pending environmental regulations affecting the utility industry in their states and regions, the Regulatory Assistance Project (RAP) is producing a series of memoranda to assist states in dealing with some of the likely questions expected to arise.

Here we consider the role that utility market factors such as the price of natural gas, can play in the context of emerging environmental regulations and in regulatory compliance strategies. Utilities will consider both regulatory compliance and market fundamentals in their business decisions regarding existing power plants. The comments provided here seek to highlight the positive aspects of looking at resource choices in an integrated manner. States that consider methodologies and approaches that help in understanding the full value of various available resources, thereby ensuring investment in the most suitable resource choice at least-cost to customers and society, could earn dividends on their advanced planning and avoid costly duplication of effort later. Finally, we provide brief descriptions and characterizations of various “process” approaches being employed by several states. The examples of state processes share one feature; they assume that a process that encourages consideration of alternatives and allows for stakeholder review will encourage better overall utility performance in an uncertain environment.

The memo is divided into the following sections:

- Market Factors Affecting Coal
- Benefits of an Integrated Analysis
- Other Review Processes

Market Factors Affecting Coal

As states conduct their own investigations into the effects of federal environmental regulations, it is critical to recognize that the activity of the Environmental Protection Agency (EPA) will be only one of the several significant groups of issues that are compelling companies to consider closing, retrofitting, or replacing older, smaller and less-efficient coal plants. Although distinguishing company decisions due to market factors from decisions based on regulatory compliance costs is more easily said than done, regulators nevertheless need to recognize the degree to which economic factors are driving retirement



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and investment decisions by utility companies. According to Sue Tierney in her article, *Why Coal Plants Retire: Power Market Fundamentals as of 2012*,

New environmental requirements can put financial pressures on coal plant operators, but power market fundamentals, and especially tightened gas-to-coal price differentials and lower electricity demand, have contributed significantly to the recent business decisions of some coal plant owners to retire some of their marginal plants. Many market observers report continued pressure on the coal fleet in the near term, at a minimum, due to these economic drivers.¹

This means that the economic case for continued operation of a coal plant could largely come down to the price differential between coal and its most likely alternative--natural gas: the lower the price of gas, the greater the risk to coal plant revenues. Lower gas prices, due to more domestic production, significant storage levels, and new pipeline projects have affected electricity prices across the country. In February 2012, the Analysis Group reported:

Natural gas prices fell from \$4.37/mmBtu in 2010 to \$3.98/mmBtu in 2011, the lowest annual average price for natural gas since 2002. Today, the spot market is trading at about \$2.50/mmBtu.²

While gas prices have been dropping, coal prices have remained high. According to the Energy Information Agency (EIA), “[d]elivered coal prices to the electric power sector have increased steadily over the last 10 years and this trend continued in 2011, with an average delivered coal price of \$2.40 per mmBtu (a 5.8 percent increase from 2010).”³

According to the Brattle Group, natural gas prices rather than pending environmental regulations are changing power market conditions and having the greatest effects on existing coal generation. They write that the energy market and potential environmental regulations have changed “substantially” since they studied the “potential for coal plant retirements in December 2010.”⁴ They indicate that the “decrease in spot and forward gas prices combined with low demand for power have caused projected energy margins and the cost of replacement power to decrease, altering the economics for coal units towards retirement versus retrofit decisions.”⁵

¹ *Why Coal Plants Retire: Power Market Fundamentals as of 2012*, Susan Tierney, Feb. 2012, at 12, http://www.analysisgroup.com/uploadedFiles/News_and_Events/News/2012_Tierney_WhyCoalPlantsRetire.pdf (Why Coal Plants Retire).

² Id. at 3, citing to Henry Hub prices set out in the Energy Information Administration, “2011 Brief: Energy commodity price trends varied widely during 2011,” *Today in Energy*, January 9, 2012. In December 2012, EIA identified the 2012 annual natural gas price as \$2.85 per MCF.

³ Id. citing to EIA, Short-Term Energy Outlook, February 7, 2012: “U.S. Coal Prices.”

⁴ Metin Celebi, Frank Graves, and Charles Russell, “Potential Coal Plant Retirements: 2012 Update,” The Brattle Group, Inc., October 2012, at 1, citing to Metin Celebi, Frank C. Graves, Gunjan Bathla, and Lucas Bressan, “Potential Coal Plant Retirements Under Emerging Environmental Regulations,” The Brattle Group, Inc., December, 2010.

⁵ Id.

In addition to collapsing coal and gas price differentials, slower than expected economic growth has caused a drop in demand for relatively more expensive coal plants that previously had been economic to operate. Prices have also moderated due to a decrease in forecasted electricity demand due to energy efficiency and other demand-side management programs. In PJM, for example, demand response and energy efficiency are beginning to play a significant part in PJM's capacity auctions. These demand-side resources, plus renewable resources, constitute approximately 10 percent of the resources clearing PJM's 2014-2015 forward capacity auction.⁶ The market has accepted these resources as less costly than other more traditional supply-side resources. These lower priced alternatives could be good news for ratepayers by lowering overall utility costs, to the degree the regulatory process requires their inclusion in company resource choice analyses.

Of course, in addition to wider market factors, it also appears that a generating plant's age and relative efficiency are important factors that should also be considered in evaluating resource choices. The Analysis Group cites to several examples from FirstEnergy⁷ and American Electric Power⁸ that strongly suggest that these factors play a significant role in generation plant retirement decisions being made by companies.

While the political rhetoric associated with retirements points to EPA regulations as being the cause of generation retirements, it is important to recognize the role that market factors are playing in company decisions to retire resources, and that there are less expensive alternatives to some existing generation.

The Benefits of Integrated Analysis

Planning is not new to the utility industry; many utilities have performed resource planning for internal purposes or to comply with regulatory requirements, over the course of several decades. What has come to be known as "integrated resource planning" (IRP) or simply "least-cost planning" is built on principles of comprehensive and holistic analysis.⁹ IRP was developed by utility regulators because they saw that traditional utility planning and investment decisions often overlook alternative resources, including end-use efficiency and renewables, whose economic and environmental characteristics could provide significant system benefits in the form of cost- and risk-reduction.

The central value in having a utility plan ahead, whether or not as part of a formal regulatory process, lies in being able to identify the best resource mix for the utility and its consumers before capital is committed and expenditures are made. The "least-cost" criterion implies the optimal resource mix is the lowest total cost over the planning horizon, given the risks faced. And, the best resource mix is one that

⁶ "Why Coal Plants Retire" at 8, citing to PJM, "Demand Resources and Energy Efficiency Continue to Grow in PJM's RPM Auction," News release, May 13, 2011.

⁷ *Id.* at 10

⁸ *Id.* at 11.

⁹ See, e.g., "Best Practices Guide: Integrated Resource Planning For Electricity," Prepared for: Energy and Environment Training Program Office of Energy, Environment and Technology Global Bureau, Center for the Environment, United State Agency for International Development.

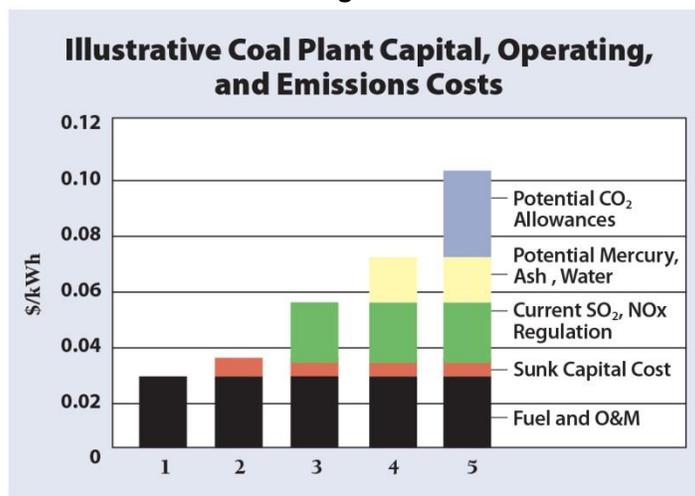
remains cost-effective across a wide range of futures and sensitivity cases that also minimize the adverse environmental consequences associated with its execution.¹⁰

In the context of an investigation into the effects of pending environmental regulations, the ideal position for a state to be in is one in which the state requires the utilities to submit regular resource plans. This is because there are existing stakeholder processes for the review of resource planning inputs, assumptions, and outputs. Approximately thirty-nine states require their utilities to file IRPs.¹¹ In a process to review the potential effects of EPA regulations on a company, a regulator could request that the utilities update their plans to reflect costs associated with, among other things, current market dynamics and likely costs associated with various environmental compliance strategies.

In the absence of a resource planning requirement, planning efforts have to start somewhat from scratch and must be completed in a quicker time frame in order to ensure that utility expenditures—and by extension their requests for retail cost recovery—will be the lowest possible given the circumstances.¹² This approach would consider a full range of feasible supply-side and demand-side options and assess them against a common set of planning objectives and criteria. The key, however, is to have an *integrated* approach that looks at all potentially available choices.

Figure 1 emphasizes the importance of planning in an integrated manner by looking ahead to all likely environmental costs that may be candidates for inclusion in utility rates. The figure compares the cost of power from an existing coal plant without retrofit, with two levels of retrofit, and with carbon costs.

Fig. 1¹³



¹⁰ “Electric Regulation in the US: A Guide,” Jim Lazar, March 2011 at 73.

¹¹ According to “A Brief Survey of State Integrated Resource Planning Rules and Requirements,” by Rachel Wilson and Paul Peterson, April 2011, 39 of 50 states have a rule or requirement for long-term resource planning or procurement.

¹² Economist Paul Chernick has dubbed this approach, “Integrated Environmental-Compliance Planning.” See discussion of Oklahoma process below.

¹³ Incorporating Environmental Costs in Electric Rates Working to Ensure Affordable Compliance with Public Health and Environmental Regulations, by Jim Lazar and David Farnsworth, October 2011 at page 23.

The first bar shows only the operating costs of the plant under existing regulations. The second bar adds the capital recovery of the remaining investment in the plant; most utilities and some regulators would consider these “sunk” costs and not a part of a forward-looking economic analysis. The third bar adds a rough amount for the costs of meeting current SO₂ and NO_x emissions regulations. The fourth bar, likewise, adds a rough amount for the costs of meeting potential mercury, ash, and water regulations. The last bar adds a rough amount for the costs of meeting potential CO₂ regulations. The point of this *illustrative* example is not to assign specific values to each element but to indicate the rough order of magnitude of these costs.

The “fully renovated” power plant in this illustrative example would have costs of about \$0.11/kWh, compared with \$0.03/kWh for the current operating costs and \$0.036 for the current fully allocated costs, including a return on the existing investment. This renovated cost is well above the estimated cost of energy efficiency, wind, and geothermal generation and approaching the cost of solar and nuclear generation. In this example, the utility and the regulator would clearly want to consider whether it is cost-effective to consider plant renovation, given potential future exposure.

Examples of Review Processes

The following discussion looks at models of processes several jurisdictions and one regional organization employed to explore these interconnected environmental, energy, and ratepayer issues. These processes are briefly described with an emphasis on the potential role of utility stakeholders (e.g., utilities, regulators, and consumer advocates) and other participants (e.g., state environmental agencies).¹⁴ This section also looks at opportunities to coordinate with other state agencies. Below, we discuss processes in Colorado, Michigan, Oklahoma, and the Midwest ISO.

Colorado

Colorado, the seventh largest coal producing state in the U.S., passed the “Clean Air Clean Jobs Act” (“the Act”) in April 2010, targeting regional haze and ozone, and establishing a 70-80 percent reduction target for NO_x from 2008 levels. Denver and Colorado’s “Front Range” had been designated under the Clean Air Act as “non-attainment” areas for ground-level ozone, a pollutant created through the interaction of NO_x, VOCs, and sunlight.

¹⁴ There are additional processes that have not been considered here. See, e.g., Iowa Utilities Board Docket NOI-2011-0003, “Utility Coal Plant Planning,” a process designed to gather “Information Related to the Potential Impact of the New EPA Regulations on Iowa Generation Plants,” <https://efs.iowa.gov/efs/ShowDocketSummary.do?docketNumber=NOI-2011-0003>. The comments submitted in Docket NOI-2011-0003 by the Iowa Office of Consumer Advocate (OCA) provide an excellent list of processes including, (1) MISO’s analysis of regional impacts on utility sector; (2) Minnesota’s collaborative and modeling efforts with EPA; (3) the Colorado Clean Air Clean Jobs Act, all of which are discussed here. The OCA comments also discuss models of regulatory compliance considered in Kentucky and Georgia. Iowa OCA comments of December 15, 2011, Section 3, pages 11-19.

In the absence of final federal regulations, the Act anticipated new EPA standards for criteria air pollutants (NO_x, SO₂, and particulates), mercury, and CO₂, and required the utility company¹⁵ to: (a) consult with Colorado Department of Public Health and Environment (DPHE) on its plan to meet current and “reasonably foreseeable EPA clean air rules,” and (b) submit a coordinated multi-pollutant plan to the state Public Utility Commission (PUC).

The Act mandated that DPHE participate in the PUC process, and conditioned PUC action on the DPHE’s review of utility proposals, affirmatively linking the two agencies’ actions. This mandate resulted in the PUC not being able to approve a plan that the DPHE did not agree would meet future Clean Air Act requirements, and the company not being able to build anything without the PUC’s approval and issuance of a certificate of public convenience. The Act also required the DPHE Air Quality Control Commission to incorporate approved plans into Colorado’s State Implementation Plan (SIP) for addressing regional haze for ultimate EPA approval.

Colorado utilities are not required to adopt any particular plan, just one that meets DPHE’s requirements and meets with PUC approval. The Act encourages utilities to enter into long-term contracts for natural gas supplies by providing protection against possible future prudence challenges by stakeholders. It also allows utilities to recover, in rates, costs associated with approved long term contracts, “notwithstanding any change in the market price during the term of the agreement.”

The Act encourages companies to evaluate alternative compliance scenarios, but requires each company to develop and evaluate an “all emissions control” case, (i.e., a scenario calling for installation of pollution controls on the coal fleet, plus an assessment of different ranges of retirements).

In the administrative process, Public Service of Colorado (Xcel) was given four months to report to the PUC with analysis results and a proposed compliance plan. The company divided its analysis into four steps (See Table 1). In Step 1, “data collection,” the company identified: (a) the coal plants for which the company might take “action” (i.e., install controls, retire, or retrofit for fuel switching); (b) emission control options and associated costs; (c) possible generation technologies that would replace retired capacity; and (d) transmission reliability requirements.

Step 2 was “scenario development.” This involves developing combinations of various actions on coal plants, assessing replacement generation (i.e., developing “Capacity Portfolios”), and testing the feasibility of approaches for reducing emissions while maintaining reliable service.

¹⁵ The “Clean Air – Clean Jobs Act,” HB 10-1365, requires “[b]oth of the state’s two rate-regulated utilities, Public Service Company of Colorado (PSCO), and Black Hills/Colorado Electric Utility Company LP, ... to submit an air emissions reduction plan by August 15, 2010, that cover[s] the lesser of 900 megawatts or 50% of the utility’s coal-fired electric generating units.” Legal Memorandum, Office of Legislative Legal Services, March 16, 2011, on H.B. 10-1365 and Regional Haze State Implementation Plan, [http://www.leg.state.co.us/clics/clics2011a/cslFrontPages.nsf/FileAttachVw/SIP/\\$File/SIPMeetingMaterials.pdf](http://www.leg.state.co.us/clics/clics2011a/cslFrontPages.nsf/FileAttachVw/SIP/$File/SIPMeetingMaterials.pdf)

In Step 3, “dispatch modeling of scenarios,” the company used its “dispatch modeling” capability to evaluate the effects of various scenarios (articulated partly by statute, the company, the PUC, and stakeholders) on the company’s entire system.

Step 4 involved the development of sensitivity analyses. At this step, the company performs analyses by varying certain key assumptions to see how the scenarios it developed and modeled under Steps 2 and 3 would perform in different futures.

Table 1. Public Service of Colorado’s Analysis	
1. Data Collection	<ul style="list-style-type: none"> • Identify Candidate Coal Units • Emission Control Options and Costs • Replacement Capacity Options • Transmission Reliability Requirements
2. Scenario Development	<ul style="list-style-type: none"> • Meet NOx Reduction Targets • Feasibility of Emission Controls • Replace Retired Coal MW • Transmission Needs Analysis
3. Dispatch Modeling of Scenarios	<ul style="list-style-type: none"> • Long-term Capacity Expansion Plan • Cost of Transmission Fixes • Coal and Gas Price Forecasts • Customer Load Forecasts
4. Sensitivity Analysis	<ul style="list-style-type: none"> • Construction Costs • Coal and Gas Prices • Emissions Costs (NOx, SO₂, CO₂) • Replacement MW for retirements • Addition of renewable resources

The overall undertaking required cooperation between the regulatory commission and Colorado’s environmental regulator, and significant effort by Public Service of Colorado. The process, including a PUC investigation, company analysis of alternative compliance strategies, issuance of a final order, and subsequent adoption of changes to Colorado’s SIP occurred in less than eight months, demonstrating the feasibility of such a cooperative effort and the ability of decision makers to address the challenges related to maintaining system reliability while responding to (as yet unarticulated) health and environmental regulatory compliance challenges.

On March 12, 2012, the EPA approved Colorado's SIP for addressing regional haze around the state's national parks and wilderness areas. According to E&E Greenwire, “the adoption of Colorado's state

implementation plan -- unlike other states' proposals -- went smoothly in large part because of Colorado's 2010 Clean Air-Clean Jobs Act.”

Process Lessons

It is important to note that the Colorado process:

- Took place in less than one year;
- Went ahead, absent certainty as to precisely what EPA regulations would require; and
- Mandated coordination between environmental and energy regulators, due to the subject matter of the challenges being addressed by the state.

Michigan

Michigan provides a unique model of regulatory coordination. Executive Directive No. 2009 – 2 requires the state environmental regulator, the Michigan Department of Environmental Quality (DEQ), to “conduct analysis of electric generation alternatives prior to issuing an air discharge permit.” As part of this inquiry, the directive also requires the Michigan Public Service Commission (PSC) to provide DEQ with technical assistance.¹⁶

The two agencies entered into a memorandum of understanding in which respective roles were articulated: DEQ would undertake air quality determinations, and the PSC would provide assistance related to determining need for new generation, and analyze alternatives, including options for energy efficiency, renewable energy, and other generation.¹⁷

Process Lessons

Executive Directive No. 2009 – 2, like Colorado’s Clean Air Clean Jobs Act, underscores the value of developing a process that links both environmental and energy regulators to analyze company electric generation choices.

Oklahoma

In June 2011, the Oklahoma Corporation Commission issued a notice of inquiry (“NOI”) in order to examine existing and pending federal regulations and legislation that could impact regulated utilities and their customers in the state of Oklahoma.¹⁸ The Commission is also examining the potential impact of such regulations on the natural gas commodity market in Oklahoma. The primary purpose of the NOI is to determine whether any amendments to the rules of the Commission are necessary.

¹⁶ Executive Directive No. 2009 – 2, “Consideration of Feasible and Prudent Alternatives in the Processing of Air Permit Applications from Coal-Fired Power Plants,” <http://www.michigan.gov/granholm/0,1607,7-168-36898-208125--,00.html>.

¹⁷ “Statutory and Administrative Review of Power Plants in Michigan,” NARUC Task Force Webinar 3, State Case Studies, Greg White, Commissioner, Michigan Public Service Commission, December 17, 2010. <http://efile.mpssc.state.mi.us/efile/docs/15958/0001.pdf>; http://www.naruc.org/Publications/White_%20Michigan%20Coal%20Plant%20Review%20Processes.pdf

¹⁸ Cause No. PUD 201100077, “In Re: Inquiry of the Oklahoma Corporation Commission to Examine Current and Pending Federal Regulations and Legislation Impacting Regulated Utilities in the State of Oklahoma and the Potential Impact of Such Regulations on Natural Gas Commodity Markets and Availability in Oklahoma.”

In its first of a series of questions, the Commission asked:

Are there alternative planning processes other than a regulated utility's Integrated Resource Plan (IRP) as described in OAC 165:35-37 that could be considered in determining the most effective strategy to include a holistic approach to Oklahoma's generation fleet and an analysis of the overall cost impact or benefits to ratepayers as it relates to federal mandates, fuel switching (converting from one fossil fuel to another type of fossil fuel), renewable portfolio standards, fuel diversity, system efficiency improvements, transmission expansions and other upcoming issues? If so, what kind?

In response, one participant, Sierra Club, proposed that the OCC adopt what the NGO called “Integrated Environmental-Compliance Planning.”¹⁹ It is an approach that, in many ways, works like an IRP. It considers supply-side, demand-side, and delivery options in an integrated manner. It focuses, however, more closely on the requirements of forthcoming public health and environmental regulations and the imminent need to take actions such as retiring, retooling, or investing in new resources. Whether a commission employs integrated resource planning or integrated environmental-compliance planning, reviewing investments in an *integrated* manner is the key. According to Sierra Club, this approach will help ensure a greater understanding of all options available that might otherwise be missed with a narrower approach:

Responding to these requirements piecemeal will result in inefficient and unnecessarily expensive decisions. The sheer number and wide coverage of these pending rules mandates that the Commission and the utilities consider their potential impact in a comprehensive, rather than case-by-case basis, for both planning and cost recovery. The Commission should expect to see the anticipated costs and the potential risks of existing and emerging regulations for the whole range of pollutants in utility evaluations of their investment proposals. Given the capital-intensive and long-lived nature of investments in the electric industry, if the final form or timing of a regulation is unknown, the analysis should include both an expected value of the cost of compliance and the range of plausible costs.²⁰

Process Lessons

Oklahoma’s process initially looks much like an NOI that any administrative agency around the country might undertake. However, one key difference is that the OCC asked up-front if its existing planning process is capable of addressing these issues. As noted in the discussion of the Colorado Clean Air Clean Jobs Act, an inquiry such as this opens up the possibility of a state- or region-wide view of alternatives.

¹⁹ Sierra Club, July 18, 2011 at page 5, Oklahoma Corporation Commission. (2011).

²⁰ See Comments of Sierra Club in “In Re: Inquiry of the Oklahoma Corporation Commission to Examine Current and Pending Federal Regulations and Legislation Impacting Regulated Utilities in the State of Oklahoma and the Potential Impact of Such Regulations on Natural Gas Commodity Markets and Availability in Oklahoma,” Cause No. PUD 201100077, July 18, 2011, <http://www.occeweb.com/pu/EPA/Filed%20Comments/2011%2077Sierra%20Club%20NOI%20II%20responses%207%2018%2011.pdf>



Midwest ISO Analysis²¹

The Midwest Independent System Operator (MISO) conducted an analysis of potential effects of EPA regulations on its system. MISO's analysis was broken into three phases. Using the Electric Generation Expansion Analysis System (EGEAS) model, MISO's first step looked at the effects of several EPA regulations on generation in MISO from a regional perspective. Using results from the first phase, MISO's next step focused on energy and congestion impacts in the MISO system, using a production cost model and transmission adequacy model.²² In the third phase, MISO developed compliance and capital cost requirements, and analyzed system adequacy, system reliability, and impacts on customer rates.²³

Process Lessons

The MISO process recognized:

- The role of market dynamics;
- That gas prices relative to coal are a key driver; and
- The importance, for scheduling purposes, of knowing when a plant will need to go offline (whether permanently or for retrofitting), and that this can be modeled but that it also needs to be ascertained plant-by-plant from utility companies.

Conclusions

Each of these processes demonstrates how a “directed” conversation between regulators, companies, and other stakeholders can be useful to regulatory commissions and provide commission staff and others the opportunity to “kick the tires” on modeling assumptions, scenario assumptions, and sensitivities related to company environmental compliance choices. Having one party undertake this work alone could result in not only a lot of work and expenditure on their part, but also an extremely complex collection of data and assumptions that will be less than useful to regulators. Alternatively, a transparent approach that explores assumptions whose attributes are generally agreed-upon can be more valuable in helping decision-makers with their work. This approach also affords commissions and staff the opportunity to make use of the expertise of various stakeholders, thereby making greater use of commission staff time and resources.

This review is designed to help regulatory commissions in their responses to new and pending environmental regulations affecting the utility industry in their states and regions. The topics considered here are likely to arise in any discussion of the effects of environmental regulations on a state's utility sector.

²¹ This discussion is based on a MISO analysis entitled “EPA Impact Analysis Impacts from the EPA Regulations on MISO,” October 2011. <https://www.midwestiso.org/layouts/MISO/ECM/Redirect.aspx?ID>.

²² Respectively, the PROMOD IV production cost model and the PSS/E transmission adequacy model.

²³ In addition to the above mentioned models, in analyzing system adequacy, MISO also used GE-MARS model.