THE EIA SHORT-TERM REGIONAL ELECTRICITY MODEL AND ITS APPLICATION IN POWER SYSTEM ANALYSIS

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Overview

The United States Energy Information Administration (EIA) developed a 13-region short-term electricity model for its monthly projections of electric power generation from fossil fuel power plants. The model has explicit representation of hourly/monthly demand and supply for each region. Data inputs and model parameters are derived from the 2005 data on generation, plant capacity, and sales published by EIA as well as data from power control areas.

The contributions of this paper are: (1) to provide forecasts and (2) to provide simulation results addressing potential impacts on gas market and trade, which have implications on efficiency, reliability, and investment. The modeling framework and model outputs provide insights into the economics of dispatching power from gas plants, trade flows, and the utilization pattern of existing transmission capacity. First, natural gas power plants are important to six of the thirteen regions, especially in peak demand seasons. Simulation results demonstrate that the model can capture the effects of load changes on generation from gas power plants. As a result, gas demand in the power generation sector can be assessed with the rest of the natural gas market and provide a more comprehensive understanding of the overall demand and supply situations. Second, hourly trade flows shed light on hourly utilization rate of transmission lines, which are essential to investment decisions in improving the reliability of the power system. Simulation results also demonstrate the benefits of inter-regional trade in improving overall generation efficiency and supply reliability. Finally, model results on hourly capacity utilization patterns provide indicators to the importance of fuel availability during peak demand hours in regions relying on imported coal, natural gas, and oil. In addition, the implied hourly utilization rate of transmission lines can help decision makers evaluate optimal investment choices in an evolving and complex energy market.

Methods

The EIA short term regional electricity model has 13 regions. They are grouped into three trading blocs: Eastern, Western, and Texas. The Eastern trading bloc has 9 regions, the Western 3 regions, and Texas stands alone. Each region has its representation of demand for, and supply of, power; each has one 24-hour load curve for each month to represent demand pattern of an average day for the month; and each has explicit representation of four fossil fuel supply curves: coal, gas, residual fuel, and diesel fuel. Nuclear, hydro power, and renewable energy are treated as exogenous variables because, in the short run, these technologies are not responsive to changes in demand.

The challenge in modeling dispatching decisions lies in empirically estimating the supply curves of fossil fuel plants. EIA uses a modified cumulative distribution function of plant capacity, sorted by plant utilization rate, as a proxy to supply curve for each fuel in each region. Computation of power plant capacity utilization rates uses two 2005 EIA data sets. The EIA Form 906 collects monthly data on generation and fuel use at the generator or plant level by states. And the EIA Form 860 collects annual generating capacity by technology and fuel at plant level. On the demand side, an average daily 24-hour load curve for each region each month is derived from the EIA

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Form 826, which collects monthly sales data by state and data from power control area. The solution algorithm for the electricity dispatching model is straightforward. For each 24-hour time period, hourly total regional supply in a trading bloc is equated to hourly total regional demand. Hourly generation from coal, gas, diesel fuel, and residual fuel for the trading bloc, as well as for each region, are determined simultaneously.

Results

The model shows three important findings. First, the model can capture historical generation patterns of coal, natural gas, diesel fuel, and residual fuel. For each trading bloc, projected monthly generation from coal and gas matched well with the historical seasonal demand and generation patterns.

Second, most natural gas power plants are used for intermediate load and peak load demand and they fluctuate with the load curve much more than coal power plants. In a tight gas market facing an above normal number of cooling degree days, the model can estimate the potential changes in gas injection into storage, which is closely watched by the commodity market. This can have profound implications on prices in the gas futures market.

Third, model results show that trade flow fluctuates by the hour. The Eastern trading bloc shows that regions such as Florida, New England, and New York import less power during peak demand hours than the off-peak hours. It is contrary to the perception derived from the monthly data, which may imply an importing region imports evenly over a 24 hour period or imports more during peak demand hours. These results may reflect the fact that imported power is cheaper than indigenous power in the early hours of each day. During the peak hour, however, importing regions have to produce more because exporting regions may not have as much to export due to higher indigenous demand. Results from the Western bloc are different; California imports correspond to load and it implies that during the peak demand hour California relies more on imports. Thus, transmission capacity becomes an essential element to its system reliability.

Conclusions

The current U.S. electricity market can be characterized by aging infrastructure, evolving load centers, and heightened links between the power sector and natural gas markets. Many reports discussed investment requirements to improve the reliability of the power system. Solutions to the infrastructure and demand problems, however, are not unique and may vary with regions. Regions such as Florida, New England, and New York, have enough indigenous capacity so each region can meet most of its own demand. However, fuel availability and environmental constraints may limit the use of certain types of power plants. California, on the other hand, faces transmission constraints and may find answers in options such as adding generation capacity near the load center, expanding transmission capacity, adopting DG technologies, or adopting demand-side management. Answers to the questions of where to invest, what to invest in, and how much to invest, lay clearly in empirical data on regional demand, generation capacity, fuel availability, and power flow. Differences in market conditions may require different strategies to ensure reliability. For regions where inter-regional delivery capacity is not binding, the issue may be on fuel supply reliability and intra-regional delivery reliability of electric power. Fuel supply, prices, and storage capacity may be as important as power delivery reliability in these regions. In regions such as California, inter-regional transmission lines are critical and need to be addressed to ensure adequate supply from exporting regions. Intra-regional delivery reliability, which is not analyzed here, can also be examined using the same modeling methodology.

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