Lower electricity prices depend on transmission capacity as well as deregulation

Competition Requires Transmission Capacity: The Case of the U.S. Northeast

By Douglas R. Hale, Thomas J. Overbye, and Thomas Leckey

Deregulation of electric power generation in the United States was partially motivated by the objective of reducing persistent regional price differences. For example, the average cost of electricity to residences in New York in 1995 was 11.1 cents per kilowatt-hour but was only 6.2 cents in Ohio. For industrial customers the comparison was 5.8 cents in New York and 4.2 cents in Ohio. The cost differences per kilowatt-hour between the adjoining states of Ohio and Kentucky exceeded 2 cents for residences. The difference was 1.3 cents for industrial customers (see the Energy Information Administration report, *The Changing Structure of the Electric Power Industry: An Update*).

State regulators and legislators hypothesized that increased competition would reduce prices in the high-price areas as imports flowed in from relatively low-cost areas. But the assumption that the existing electrical grid can carry power from low-cost generators to currently high-cost regions is just an assumption and one that has received remarkably little scrutiny from policy analysts.

This article examines the ability of the electrical grid to support trade in real power in the northeast U.S. power market. We estimate the effect on prices in New England (NEPOOL) and New York (NYPP) of greater exports from Michigan, Indiana, Kentucky, Ohio, West Virginia, and northern Virginia (ECAR), and most of Pennsylvania, New Jersey, and Maryland (PJM). The article also assesses the prospects for additional short-run price equalization from modifying the grid itself.

In our research we compared electricity flows during peak demand as experienced in summer 1997 under two governing regimes. In the first scenario we modeled use of the transmission system as limited by currently used engineering-based plans for dealing with transmission system constraints, which do not necessarily minimize generation costs. In the second "free trade" scenario, we minimized systemwide costs without the imposition of trading limitations by the Federal Energy Regulatory Commission (FERC) or NEPOOL, but we did include the physical limits of the transmission system.

At peak demand essentially all capacity is committed

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throughout the study region. To simulate the introduction of free trade in the presence of more dramatic price differences, the peak demand in the lower-cost regions, PJM and ECAR, was reduced in increments up to 30 percent. This modeling assumption freed low-cost capacity for potential export to high-cost areas. The impact of the transmission grid on trade was both to facilitate and to constrain the displacement of high-cost suppliers as the supply of low-cost capacity increased.

In our simulation, despite the availability of low-cost capacity in PJM and ECAR, prices near Buffalo and throughout most of New England remained high because transmission constraints prevented low-cost generators from selling power to these areas. To increase actual supply and to reduce further the price differences required changes to the grid itself. We explored two commonplace remedies: an "increase local supply" solution and an "increase import potential" solution. Both had the desired effect of greatly reducing prices. Policies that allow competition only among electric generators without additional changes in the design and regulation of the transmission system will not deliver the dramatic price reductions that motivated policymakers to introduce competition into generation.

THE MODEL

THE MODEL USED IN OUR RESEARCH CONSISTS OF A REPRESENTATION of the electrical grid and demand, the costs of the generators, and an algorithm for finding the least costly ways of meeting demand with and without trade constraints. The network model used was the FERC form 715, *Annual Transmission Planning and Evaluation Report*, for the anticipated 1997 summer peak filed by NEPOOL. This model contains 9,270 buses (points at which electricity is either added to or removed from the transmission grid), 4,601 loads (locations of electricity demand), 2,506 generators, 12 direct-current lines (used to carry large amounts of power short distances), and 14,840 alternating-current lines and transformers. The model has a relatively detailed representation of the transmission grid in NEPOOL and NYPP; less detailed, but still adequate models are included for ECAR, PJM, and parts of Canada. Total load at the summer peak is 356,274 megawatts (MW). The study examined the impact of the transmission system on imports from ECAR and PJM (the "export" areas) into NEPOOL and NYPP (the import areas). Except for the loads in ECAR and PJM, the load is assumed constant throughout the analysis.

The base case models 2,506 generators (1,630 of which are in the four North American Reliability Council [NERC] regions of immediate interest), corresponding to all the generators reported on FERC form 715 for the 1997 summer peak. The FERC 715 requires utilities to file power-flow base cases for transmission systems, including a physical description of the system. The output of generators whose costs could be estimated was assumed to be set by system operators. The output of generators whose costs could not be estimated was set to the level in the FERC 715. That is, such generators were treated as must-run facilities.

We encountered two problems in estimating operating costs of these generators. First, the FERC 715 inventory of generators does not report operating costs. Therefore, generators reported on the FERC 715 must be identified and matched with generators reported on other survey forms such as FERC form I (*Annual Report of Major Electric Utilities, Licensees and Others*) or form EIA-412 (*Annual Report of Public Electric Utilities*) where cost data are collected. Once matched, operating cost data for specific generators can be prepared for the model. Table 1 displays summary results of matching FERC 715 generators to generators reported on other forms. New England and New York contain many nonutility generators, virtually none of which are respondents to FERC form I. Coverage in those two NERC regions is therefore less complete than in PJM and ECAR, where larger utility units are predominant.

Though many units could not be matched for costing purposes, their technology character could be identified. Many of these units were either hydro or pumped storage, and because these units would be expected to have low operating costs, they can be dispatched using generically low costs. Table 2 reports the capacities for which reported costs were available and thus those that were available for dispatch in our model.

In early runs of our model, as significant congestion problems appeared in the NEPOOL network, it became increasingly important to develop costs for as many NEPOOL generators as possible. An alternative methodology was used to develop costs for a few critical genera-

Table 1

Number and Percentage of Generators, Matched and Costed, by NERC Region

	No. of FERC 715 Generators	Generators Matched	Percent
NEPOOL	468	120	26
NYPP	400	147	37
PJM	464	308	66
ECAR	298	267	90
Total	**1630**	**842**	**52**

Table 2

Costed Capacity Using FERC Form I Data, by NERC Region (Megawatts)

	Costed Capacity	Hydro, Pumped Storage	Total	Coverage (%)
NEPOOL	13,039	1,130	18,083	78
NYPP	17,019	4,245	26,675	80
PJM	39,265	2,031	46,187	89
ECAR	71,125	1,872	74,245	98
Total	**140,448**	**9,278**	**165,190**	**91**

tors in NEPOOL. The National Energy Modeling System (NEMS) produces estimates of operating costs for plants that are similar in technology, location, vintage, and type of ownership. Using NEMS output, operating costs were estimated for an additional 170 units in NEPOOL and one large nonutility generator in ECAR. NEMS variable costs by plant group were divided by generation to arrive at a cost of generation for each of the plants modeled in NEPOOL. Then those plants were grouped by technology and a generation-weighted average was determined. Fuel costs were taken from FERC form 423 data at the state level for 1995; dual-fired units were assumed to consume equal shares of oil and gas. Renewable technologies incurred no fuel costs. Table 3 shows the variable costs derived by plant type (exclusive of fuel).

As noted above, many of these additional units were either hydro or pumped storage units, but 62 were fossil units, many of which are small internal combustion units, and the largest of which is a 214-MW coal steam unit in Connecticut. The amount of capacity added to economic dispatch by using this method was relatively small—2,422 MW in NEPOOL and 1,131 MW in ECAR—bringing the total dispatched capacity to more than 144 gigawatts, or 91 percent of the total capacity modeled. Because of the critical location of these units, however, the effects on the transmission network were pronounced.

RESULTS

DETERMINATION OF THE LEAST-COST WAY OF MEETING demand is sensitive to numerous physical constraints imposed on the market by the transmission system. The solution of this problem requires the use of an optimal power flow (OPF) algorithm. The OPF algorithm was first formulated in the early 1960s (J. Carpienter, "Contribution à l'étude de Dispatching Économique," *Bulletin Societé Française Electriciens*) and has been an area of active research ever since. The goal of the OPF is the minimization of total generation costs subject to the physical limits of the grid and generators to produce and transport electricity. Over the years a wide variety of different solution approaches have been proposed. We use linear programming-based methods. The details of our algorithm are presented in our technical paper.

Analysis tools, such as the OPF, yield a wealth of information, but the sheer volume of the information makes it difficult and time consuming to interpret. In order to aid the system analyst in finding patterns in the data, we use the discrete locational marginal-cost data produced by our optimization model to generate a continuous contour representation similar to the display of temperatures on a weather map.

To create a contour map, a technique for drawing the image must be developed because the data only exist at points where a bus is defined. To create the contour image, an imaginary grid is laid across the region, and a *virtual value* is calculated for each point in the grid. These virtual values are then mapped to a color and the resulting contour is drawn. The virtual value is determined by taking a weighted average of the data points throughout the region—that is, data points that are closer to the virtual grid point are weighed more than those farther away. These virtual values are then represented by a color in the grid, and the resulting contour is plotted.

The base case, "regulated trade," supposes that each region imports or exports the amounts specified in the FERC 715 file. That is, ECAR exports a total of 2,277 MW, PJM imports 1,408 MW, NYPP imports 1,304 MW, and NEPOOL imports a total of 2,920 MW, of which 620 MW come from New York. The base case reflects the regulated nature of the industry and the NERC plan for managing peak demand.

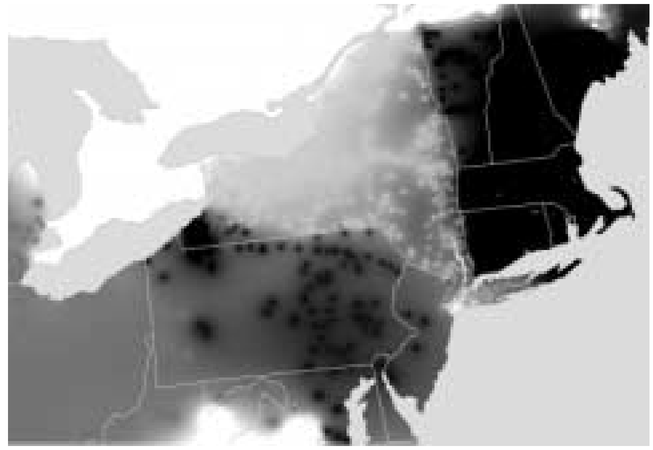
The base case was optimized by using the OPF algorithm with the assumption that the generators in each of the four areas were dispatched to minimize cost given the exports and imports specified in the NERC plan. This resulted in a solution with a total operating cost of

Table 3

Supplemental Operating Costs for NEPOOL Generators (1995 dollars)

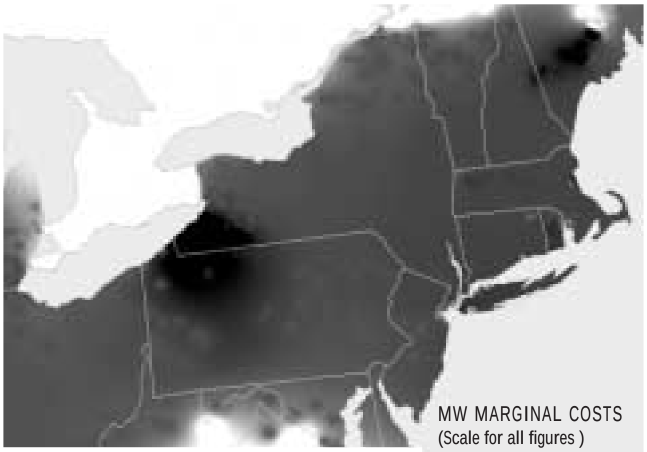
Technology	Variable Operating Costs ($millions/kWh)	Capacity (megawatts)
Old coal	20	34
New coal	20	52
Scrubbed coal	13	181
Oil/gas steam	23	45
Oil turbine	41	1
Gas turbine	16	2
Oil/gas turbine	36	10
Gas combined cycle	18	305
Oil/gas combined cycle	25	186
Biomass	46	195
Municipal solid waste	46	281
Hydro pumped storage	4	1,130

Figure 1



Prices Under "Regulated Trade"

Figure 2



Prices Under "Free Trade"

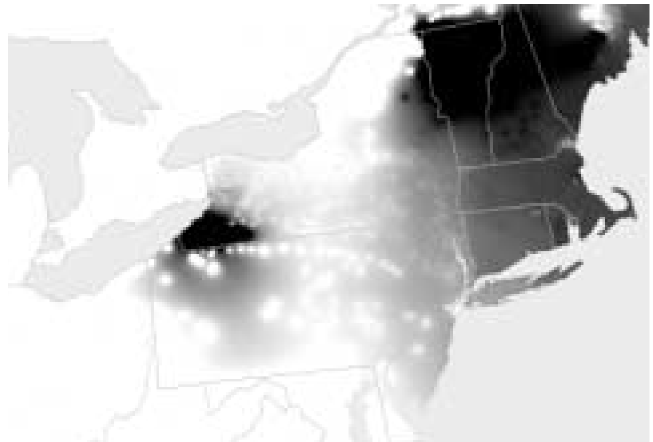
$4,555,491 per hour. Because of congestion the prices in each of the areas were not identical. The average prices for each of the areas are shown in the "Regulated" row of Table 4. Figure 1 displays the regional variation in prices using a gray color scale in which darker corresponds to higher prices. White indicates areas, such as Canada and southern Virginia, for which prices were not determined.

The "free trade" case is defined as the minimum cost of meeting demand without regard for NERC trading limits imposed on the first case. This solution simulates what perfect competition across these four regions would yield at the fixed demand levels specified in the model. The least-cost way of meeting demand resulted in an overall operating cost of $4,537,561 per hour, only 0.4 percent below that of the previous "regulated trade" solution. However, there is more interregional trade in this scenario than in the "regulated" base case. Under "free trade" ECAR exports 2,620 MW, PJM imports 2,372 MW, NYPP exports 44, and NEPOOL imports 3,736 MW.

As shown in the "Free trade" row of Table 4, prices in PJM and NEPOOL are lower under competitive trade than under regulation, but the average price in ECAR and New York is higher. As trade equalizes prices, production in ECAR and NYPP rises, and PJM and NEPOOL enjoy the benefits of increased supplies of cheaper power. Figure 2 displays the regional variation in the prices, using the same color key and scale as Figure 1. Note that there is no longer a significant regional variation, although localized price differences resulting from line congestion are apparent in western New York and central Maine.

Both the "regulated" and "free-trade" cases assume high demand in all regions and thus little additional low-cost generation is available to export. To simulate the possibilities provided by additional low-cost supply and gains to trade from its export, we arbitrarily "decrease" demand in ECAR and PJM to free generation capacity for export to other regions. The results of decreasing the load in ECAR and PJM by 10 percent are shown in Table 5 and Figure 3.

Figure 3



"Free Trade" Prices with 10% Load Reduction in ECAR and PJM

A 10 percent reduction in load frees up 11,744 MW for potential export. Although this amounts to only 3.3 percent of total system load, it is about 25 percent of the load in NYPP and NEPOOL. The immediate effect of lower demand is to reduce the average price in ECAR and PJM by about 50 percent, as shown in the second row of Table 5. The increased supplies also reduce average price in New York by about a third.

Interestingly, New England is almost unaffected by the increase in potential supply from ECAR and PJM. Under the optimal dispatch at peak demand, free trade leads to NEPOOL receiving 1,425 MW from New York. But when demand is reduced 10 percent in ECAR and PJM, NEPOOL's imports from New York decline slightly to 1,400 MW. The calculated prices actually increase by about 8 percent! The reason for these differences is congestion in the transmission system. In the case with the 10 percent load reduction there are actually nine congested lines in NYPP and seven

Table 4

Regulated and Free Trade Average Bus Marginal Prices (Dollars per megawatt-hour)

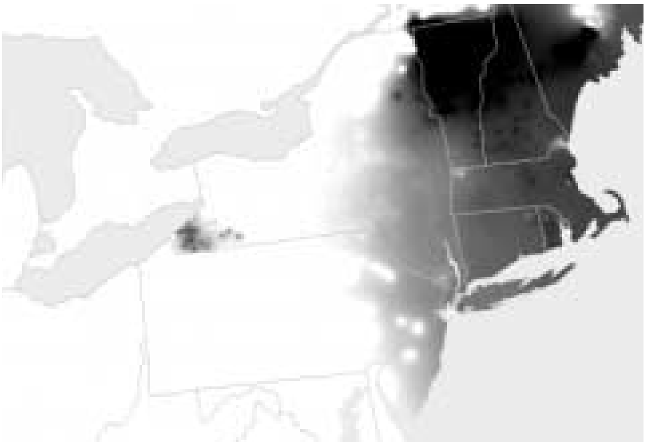
	ECAR	PJM	NYPP	NEPOOL
Regulated	32	44	26	49
Free trade	36	35	38	37

Table 5

Average "Free Trade" Prices with Load Reduction in ECAR and PJM
(Dollars per megawatt-hour)

Megawatts of Load Reduction (%)	ECAR	PJM	NYPP	NEPOOL
0 (0)	36	35	38	37
11,744 (10)	17	19	25	40
23,488 (20)	15	16	24	39

Figure 4



"Free Trade" Prices with 20% Load Reduction in ECAR and PJM

Figure 6

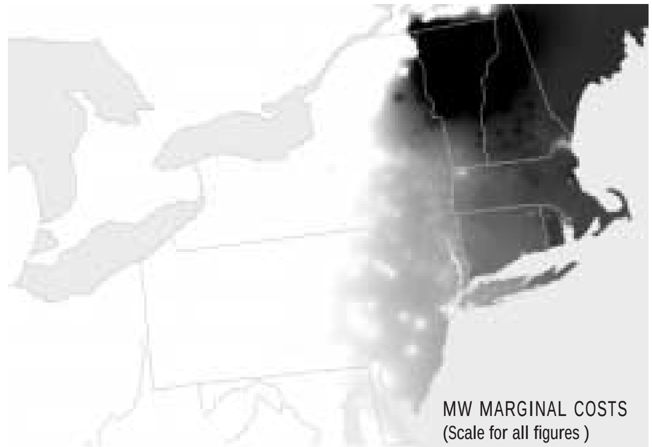
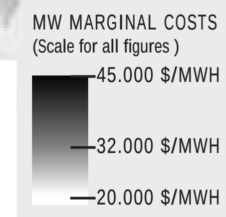


Figure 3 with Generator 6642 Turned On and Modified 115-kV Line Limit in Maine



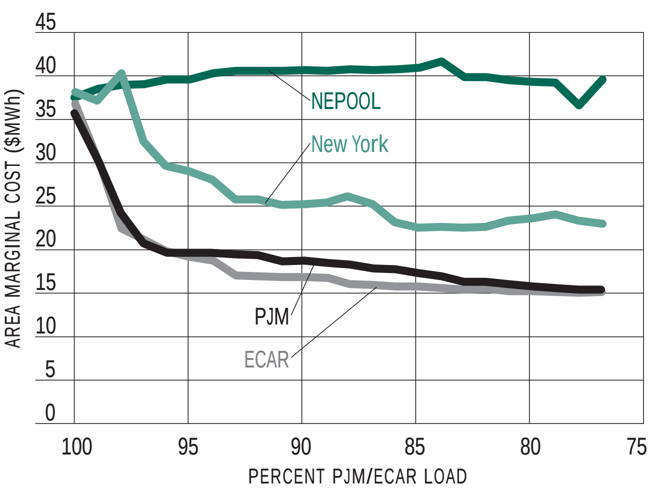
congested lines in NEPOOL. This compares with just four congested lines in NYPP for the peak demand (free trade) case with again seven in NEPOOL. Of course, whether or not congestion occurs its impact is highly dependent on both the underlying line limits and the assumed set of controls available to the OPF.

To determine whether trade alone would be sufficient to reduce the price peaks, demand in ECAR and PJM was sequentially reduced to less than 80 percent of peak. As shown in Figures 4 and 5, an additional 10 percent reduction in demand significantly lowers average price in the supplying regions but only reduces the average price in New York an additional 4 percentage points. Prices in New England were virtually unchanged as a result of additional low-cost capacity outside of New England.

The persistence of high prices in the face of idle low-cost capacity suggests that the only effective way to increase actual supply would be to change the grid. Three areas had particularly high prices in the 10 percent load reduction case: central Maine, extreme western New York near Buffalo, and the high price differentials between northern New York and Vermont.

Figure 5

Variation in Area Average Marginal Costs with Respect to Percentage Base-Case Load in ECAR/PJM



The price differential in central Maine stems from congestion on a single 115-kV line feeding power from a set of generators to the remainder of the system. In the base case the line's limit is 74 megavolt amperes (MVA); changing this limit to 91 MVA removes the congestion and hence the price differentials. The high prices in western New York arise from a combination of high demand, lack of local generation, and congestion on several of the lines supplying power to the region. To eliminate this region of high prices we examined the marginal costs of the off-line generators in the region and then turned on the generator with the lowest marginal cost of those units that were off line, which resulted in a decrease in price in this region from about $115 per megawatt-hour down to $16 per megawatt-hour. As shown in Figure 6, this small change significantly affected prices across a relatively large region.

The last high-price anomaly we considered was near the border between New York and Vermont. In that case the culprit was congestion on a 115-kV line whose base-case limit is 179 MVA. Figures 7 and 8 show how prices change across the Northeast as the limit in that line is increased to 210 MVA and then to 250 MVA, at which point it is no longer binding. Relaxing this limit decreases the prices in northern New England but increases prices across much of New York, and even induces congestion in a line in northern Pennsylvania. As the limit is increased more power from New York can flow into New England, and the interregional flows increase by about 500 MW between the Figure 3 and the Figure 8 cases.

CONCLUSION

OUR RESEARCH EXAMINED THE CONSTRAINTS TO TRADE IN electricity resulting from both regulatory and physical lim-

Figure 7

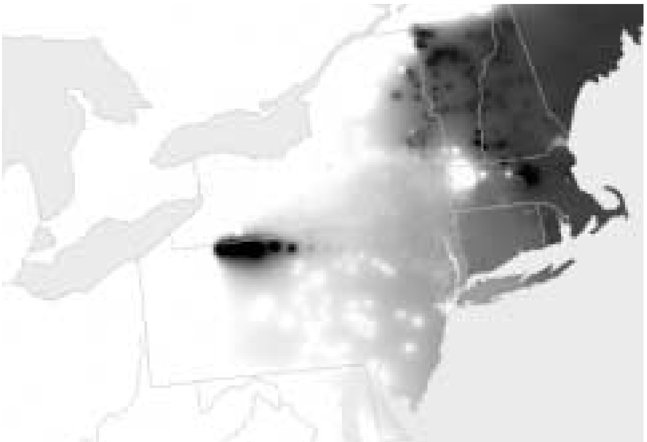


Figure 3 with New York to Vermont Limit Increased to 210 MVA

its in the transmission grid in the northeastern United States. The main results are as follows:

- Average prices in New York are very sensitive to increased supplies from PJM and ECAR. Additional supplies resulting from a 10 percent decrease in demand in PJM and ECAR reduce average price in New York by about a third. An additional 10 percent reduction reduces prices by an additional 4 percentage points.

- New England is almost unaffected by the increase in supply potential from ECAR and PJM because imports through New York are limited to roughly 1,450 MW by physical limits in the grid.

- Prices are extremely sensitive to assumptions about transmission-system limits and generator costs and availability. We demonstrated that a small change in a transmission line limit or the addition of a relatively small generator had large effects on competitive prices across a large region. Although the sensitivity of efficient electricity prices to transmission grid constraints is certainly well known, the high degree of sensitivity found in the case study of the northeastern United States is surprising.

These results should be understood for what they are. Our investigation of the interaction of generator competition with the nature of the grid is more illustrative than predictive. Our assumptions probably deviate from reality: intraregional costs are not being minimized under current regulations; our model does not capture the potential for strategic manipulation by deregulated generators; and the restructuring of regulation of generators is unlikely to lead to perfect competition as implied by our systemwide cost-minimization algorithm.

Nevertheless, our analysis shows that free trade and competition could greatly reduce wholesale prices in New York. Free trade and competition alone are not enough to significantly reduce prices in New England: generators in NEPOOL may have substantial protection from distant competitors. But even in the case of New England, a limited number of investments in the electrical grid could significantly reduce prices.

Figure 8

Figure 3 With New York to Vermont Limit Increased to 250 MVA

readings

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