The Electric Transmission Network: A Multi-Region Analysis

by
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As competitive electricity markets become more widespread, interregional power trading is likely to increase. Any increase in interregional trading will place additional demands on the electric transmission network. This paper examines the ability of the existing transmission network to respond efficiently to increased trade over four reliability regions in the northeastern United States. A power flow model is used to analyze the potential for expanding electricity trade, given the operational constraints of the transmission system and the availability and cost of generators. Results include impacts on marginal costs of electricity, regional variations in costs, interregional trade levels, and local transmission operations. The study finds that the potential for increased trade, while significant, is limited by congestion on the transmission network, especially with regard to the New York -New England interface. The analysis also suggests that the representation of transmission services in the National Energy Modeling System should include certain congestion constraints.

Background

This paper is a followup effort to a preliminary analysis published in 1998[1] in which the electric transmission system for the New England Power Pool (NEPOOL) was used to determine whether transmission bottlenecks—referred to as congestion—might prevent consumers from receiving the full benefits of competition. In other words, would transmission congestion cause consumers in some areas to pay relatively high prices for power even though lower cost generation was available in other areas? The key result of that study was that there did not appear to be transmission congestion problems within the New England region. As a result, competitive electricity prices would be similar throughout the region. However, the study did find that imports of potentially cheaper power from Canada were limited by NEPOOL's inability to maintain acceptable voltage levels.

A second key finding of the previous study was that, to some extent, the relatively high electricity prices in New England were due to the extensive use of "must run" generators. Generators are usually referred to as "must run" for engineering or system reliability reasons. Among the more common reasons why certain generators are necessary for reliable system operations are the need to maintain adequate voltages, reactive power requirements, reserve requirements, or unit commitment requirements. Occasionally, economics dictates that relatively expensive units are dispatched, for example, as a means of managing congestion. This may be generically referred to as "out-of-order" dispatching.[2] Out-of-order dispatching results in costs which exceed those obtained under a strict merit order dispatch (low to high cost) and which may have significant effects on marginal cost. The necessity of maintaining system reliability and the consequent out-of-order dispatching also illustrate the limited relevance of rated transmission line capacities in calculating actual transmission potential.[3]

This study builds on the earlier work in two ways. First, it considers a much more disaggregated representation of the NEPOOL transmission network than that used in the earlier study. The more detailed analysis is being used to determine whether potential bottlenecks exist that may not be apparent with the higher level of aggregation used in the earlier study. This study includes

[1]Energy Information Administration, "An Exploration of Network Modeling: The Case for NEPOOL," *Issues in Midterm Analysis and Forecasting 1998*, DOE/EIA-0607(98) (Washington, DC, July 1998), web site www.eia.doe.gov/oiaf/issues98/modtech.html.

[2]Strictly, out-of-order dispatching refers to operating a generator whose costs of production exceed those of another idle generator.

[3]As with the events of July 6 and July 19, 1999, in the eastern half of the Pennsylvania-Jersey-Maryland (PJM) interconnection. Voltages were severely reduced because of inadequate incentives for generators to produce reactive power. See U.S. Department of Energy, *Report of the U.S. Department of Energy's Power Outage Study Team* (Washington, DC, March 2000), pp. 5 and 10.

2,117 buses,[4] 468 generators, and 816 load centers, as compared with 148 buses, 85 generators, and 82 load centers used in the previous study. Second, it considers the potential for electricity trade across much of the northeastern United States. The previous study considered only trade with Canada. This study includes four large regions encompassing an area stretching from Maine to Indiana. The increased coverage and detail come at a cost. Unlike the earlier study, where both real and reactive power were explicitly modeled, this study emphasizes a real power solution in finding the lowest cost way to meet demand. This approach was taken because modeling both real and reactive power would be too complex for the large number of buses, generators, and load centers in the regions.[5]

The objectives of this study are twofold. The first objective is to determine whether, under competition, opportunities exist for increased power flow among the regions considered in this analysis and whether competitive trade would be enough to drive down electricity prices across regions. To the extent that these opportunities exist, they would result in power flows among regions and price changes that may need to be represented in the National Energy Modeling System (NEMS) Electricity Marketing Module (EMM).[6] Currently, the EMM specifies limits on power flows using estimates from the North American Electric Reliability Council (NERC).[7] The current study can be viewed as checking whether these limits are valid in a more competitive environment. The EMM accounts for contractual trade across regions and also considers additional "economy trade," which arises from differences in the relative costs of producing power in the various NERC regions, subject to transmission limits.

The second objective is to identify certain transmission constraints, either system stability problems or congestion, which would affect any new trade opportunities and determine their impact on NEMS. Currently the EMM allows all generators in each region modeled to meet load anywhere in that region. In the EMM generating units are usually dispatched based on their merit order—that is, from the lowest to the highest cost—as load requirements increase. However, there are some generators (owned by nonutilities) that are assumed to be "must-run" units in the EMM. Historically, these units have been operated on a regular basis because of contractual agreements or because of system operation requirements, despite their higher costs. This affects both fuel consumption patterns and electricity prices. The power flow cases modeled here provide information on the manner and extent of out-of-order dispatch, especially with regard to congestion patterns.

The paper provides a specification of the model used to analyze the transmission system and a description of the assumptions and data. Four cases are considered: two that model peak demand conditions and two that model "shoulder-level" demand. Marginal costs across the four regions are examined, as well as consequent trade patterns for each case. A comparable NEMS case that examines trade between New York and New England is discussed. An examination of congestion patterns illustrates why imports of electricity into NEPOOL are constrained.

Overview of the Network Model

In order to analyze impacts of opening the transmission system to new participants, the Energy Information Administration (EIA) has developed a detailed representation of the transmission grid for several regions of the United States. These regions include the New England Power Pool (NEPOOL), New York Power Pool (NYPP), Mid-Atlantic Area Council (MAAC), and East Central Area Reliability Coordination Agreement (ECAR) (Figure 1).[8] In the initial effort EIA developed a representation of NEPOOL that included 148 buses with 85 generators and 82 load centers. Peripheral NERC regions and Canada were "equivalenced."[9] The greatly enhanced representation in this model (compared with the model used in the first study) contains 2,117 buses, 468 generators, and 816 load centers for NEPOOL. The network elements for the four regions used in this study (NEPOOL, NYPP, MAAC, and ECAR) are shown in

[4]Buses represent points where major pieces of electrical equipment connect to the grid or where major transmission lines meet. In the model described herein, buses represent any point where power flow equations must be balanced.

[5]The analysis accounts for alternating current indirectly by checking to assure that voltage levels are maintained for the power flow solution. Because of the detailed level of this analysis, it was not possible to include alternating current explicitly due to the computational difficulties that occur when both of the components of alternating current (real and reactive power) are modeled.

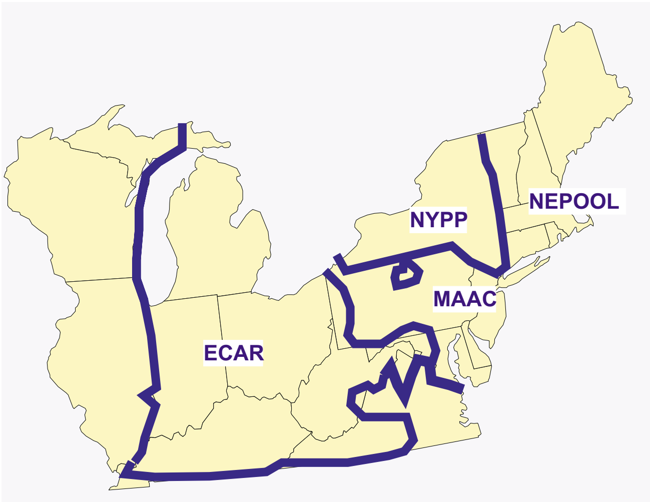
[6]For a description of the EMM see Energy Information Administration, *The Electricity Market Module of the National Energy Modeling System: Model Documentation Report*, DOE/EIA-M068(2000) (Washington, DC, January 2000), web site ftp://ftp.eia.doe.gov/pub/pdf/model.docs/m068(2000).pdf. For an overview of NEMS see Energy Information Administration, *The National Energy Modeling System: An Overview 2000*, DOE/EIA-0581(2000) (Washington, DC, March 2000), web site www.eia.doe.gov/oiaf/aeo/overview/index.html.

[7]Energy Information Administration, *The Electricity Market Module of the National Energy Modeling System: Model Documentation Report*, DOE/EIA-M068(2000) (Washington, DC, January 2000).

[8]The regions used in this analysis are part of the NERC regions that were formed to assure the reliability of the electricity transmission network. One of the NERC regions is the Northeast Power Coordinating Council. NYPP and NEPOOL are subregions of this Council.

[9]"Equivalencing" is a method used to reduce computations when analyzing electrical networks. It involves replacing a network with a simplified representation that has the same electrical properties as the original network.

Figure 1. North American Electric Reliability Council (NERC) Regions in the Northeastern United States



Source: Office of Integrated Analysis and Forecasting.

Table 1.[10] This multi-region transmission network is the framework for determining opportunities to increase interregional electricity trade.

The possibility of increased multi-region trade is of considerable interest because of the potential for economic benefits and environmental impacts. Multi-region electricity trade could result in better utilization of low cost generators in some regions, curtailing usage of higher cost units in other regions and allowing consumers to benefit from lower prices. With increased electricity trade, emissions such as sulfur dioxide and nitrogen oxides could be affected both in the aggregate level released and in their spatial distribution. This possibility has raised concerns in States that could experience higher concentrations of pollutants as a result of power transfers across broad geographic areas.

Assumptions

In order to perform the analysis of the electrical transmission network several assumptions were made. The major assumptions are discussed below.

The demand levels for electricity in this study were estimates for the peak summer hour in 1997 (most recent year for which data were available) that were used for planning purposes by utilities and, as a result, may be different from those actually experienced on the network. Those data were derived from Form FERC 715, "Annual Transmission Planning and Evaluation Report."[11] It was also assumed that customers would require time to adjust their usage of electricity in response to price changes or network conditions. The following fixed demand levels were assumed: 21,350 megawatts for NEPOOL, 25,805 megawatts for NYPP, 47,687 megawatts for MAAC, and 69,754 megawatts for ECAR. NERC regions on the periphery of this area were equivalenced.

Capacity available to NEPOOL from Canada was assumed to be fixed at 2,300 megawatts, representing the maximum transfer capability that could reliably be available at the time of the summer peak.[12] This is an estimate of capacity that would be available during peak periods; higher levels of power transfer are possible.[13]

Generating units have efficiencies that vary depending on the level of their output. Efficiency increases over most of the output range as generators "ramp up" toward their maximum rating level. For this study, the efficiency of generators was assumed to be constant over the full range of output levels.[14] This assumption leads to constant costs per unit of production over the range of output levels for any given generator. Although this simplifying assumption does not account for the reduced efficiency of generators when they are operated at the low or high end of their capabilities, it was used

Table 1. Transmission Network Elements Modeled by NERC Region

Region	Buses	Transmission Line Segments	Load Centers	Generators
NEPOOL	2,117	2,855	816	468
NYPP	1,342	2,022	672	400
MAAC.	1,492	2,338	698	463
ECAR	823	2,013	694	298
Total.	**5,774**	**9,228**	**2,880**	**1,629**

Source: Form FERC 715, "Annual Transmission Planning and Evaluation Report" (1997).

[10]The distribution network, the system of lower voltage lines (usually less than 69 kilovolts) that distribute power locally, is not included because it imposes computational complexity and offers little additional information on the interregional transmission network.

[11]Federal Energy Regulatory Commission, Form FERC 715, "Annual Transmission Planning and Evaluation Report," case nepp97s.raw.

[12]Significant Canadian imports are also delivered to both NYPP and ECAR.

[13]For June 15, 2000, ISO New England reported Canadian capacity deliveries of 2,508 megawatts, in order to meet a peak load of 16,675 megawatts. See web site www.iso-ne.com / power_system / morning_report_external.html.

[14]The assumption of constant fuel costs per unit output between minimum and maximum operating levels is an approximation. Operating costs are U-shaped, that is, they are relatively high at the extremes of the operating range and lower in the region between the extreme points.

because attempts to estimate realistic efficiency curves for the model were not successful.

The study also excluded the variable operations and maintenance (O&M) costs for generators in the dispatch decision. Generally the variable O&M costs are small (ranging from about 0.1 mills per kilowatthour for turbines to 3.3 mills per kilowatthour for coal plants), and dispatching decisions would not be expected to be altered significantly when these costs are not considered.

Unlike the 1998 study, where the aggregation levels permitted explicit analysis of reactive power, this study does not address the tradeoff between real and reactive power directly in finding the lowest operational cost for a region or an entire system. Reactive power is critical to maintaining voltage in an alternating current system and is needed by motors and by electrical devices with motors to function properly. Most of the time, reactive power is produced coincidentally with real power. Consequently, utilities have traditionally billed residential customers for real power only.[15] However, there are times when meeting the demands for reactive power requires generators to reduce production of real power. At those times there is an economic cost associated with meeting the reactive power needs of the system. Generators in a competitive market would be expected to weigh the profit from producing real power against that from producing reactive power before making their output decisions. The model used in this analysis does not simulate that tradeoff. Instead, the model computes the lowest cost of meeting real power demand and then checks voltages to assure that they are adequate (using a power flow model). Thus, the model includes the effects of reactive power in an indirect manner, including the limits on the reactive power that can be produced by electric generators.[16]

Modeling Approach and Data Quality

The analysis was performed using a representation of the electric transmission network for four regions: NEPOOL, NYPP, MAAC, and ECAR. The network was constructed using data from Form FERC 715 for the capacity of transmission lines, the power that would flow at the time of peak demand, and generator characteristics such as real and reactive power levels and voltage information. Minimum-run levels, ostensibly some type of must-run condition, are indicated for some of the units in the original case filing. These minimum requirements were included in all power flow solutions. The reference case models the 1997 summer peak (the most recent year for which data are available). Demand levels in each of the regions are not actual peak loads obtained in 1997, but rather those forecasted for planning purposes before the fact.[17] The modeling software, PowerWorld®, is a power system simulation package that, among other things, contains a power flow solution algorithm.[18]

Cost data for generators were developed by applying three methodologies.[19] The primary approach was to collate the generators described on Form FERC 715 with the detailed operating characteristics available from Form FERC 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities." Because of different naming conventions, matching generators from their physical description on Form FERC 715 with the cost characteristics available from Form FERC 1 could not be easily determined, leading to a degree of uncertainty. For these generators, operating costs were developed by applying average annual heat rates[20] to the delivered

[15]Industrial customers, however, are frequently forced to adhere to strict reactive power constraints and are charged explicitly for their inability to do so.

[16]Some configurations of generator outputs will meet real power demands but fail to provide enough reactive power to deliver useable power: voltages are either too high or too low. The procedure used here weeds out such seemingly feasible solutions. See the 1998 EIA study for a discussion of the consequences of ignoring the effects of reactive power in trade with Canada.

[17]For example, respondents to Form FERC 715 planned on a peak load for MAAC of 47,687 megawatts. Actual peak load for summer 1997, according to the PJM Independent System Operator, was 49,406 megawatts (July 15, hour ending 5 P.M.), which at the time constituted the all-time high demand in the region. Actual peak load was 44,302 megawatts in 1996 and 48,524 megawatts in 1995. See web site www.pjm.com.

[18]See web site www.powerworld.com for more information about the PowerWorld® software.

[19]All data are available on request from Tom Leckey (202-586-9413, thomas.leckey@eia.doe.gov).

[20]Heat rates are the quantities of energy, usually expressed in British thermal units (Btu), needed to produce 1 kilowatthour of electricity. It takes about 3 Btu of energy input to produce 1 Btu of electricity from a typical baseload fossil-fuel unit. In this analysis the heat rate was multiplied by the cost of the fuel to approximate the variable cost of producing electricity. Other costs that contribute to the total generating cost include the O&M costs, which usually are small relative to the fuel costs and were omitted from this analysis.

cost of fuel as reported on Form FERC 1 for 1995.[21] 1995 is the latest year for which complete data could be compiled.

Faced with the difficulty of obtaining power flow solutions in early model runs, it became increasingly important to develop costs for as many generators as possible.[22] Thus, two alternative costing approaches were employed. Form EIA-867, "Annual Nonutility Power Producer Report," collects information on most of the operating characteristics for nonutility generators but does not include fuel costs.[23] For identifiable nonutility combined-cycle units, small gas turbines, and small fossil steam units, average annual heat rates were developed from Form EIA-867 data and applied to State-level average prices for fuel received by electric utilities, as reported on Form FERC 423. Nearly 6 gigawatts of capacity (3 percent of the total) was modeled in this fashion. Units identifiable as hydroelectric or pumped storage, nearly 11 gigawatts, were dispatched using low operating costs on the assumption that they would be applied under any peak scenario. No adjustment was made to account for seasonal variations in hydroelectric generation that may have occurred in either 1995 or 1997.

All the remaining capacity, about 12 gigawatts of generating capacity (6 percent of the 205 gigawatts total) was excluded from the optimal dispatch; instead, it was assumed to be committed to the generation levels reported on Form FERC 715, and their output was fixed. This nondispatchable capacity is of interest because it is a potential distortion to the actual dispatch patterns if these units are inframarginal providers during their hours of operation. Further, one of these withheld units (432 units with an average size of 29 megawatts) could be the marginal unit and, in reality, would set the market price. Because of this possibility, there is increasing uncertainty regarding the calculated marginal cost as more units are excluded from the group of units included in the optimal solution.

Beyond the difficulties associated with collating two distinct data sets, there are other problems that may affect the analysis presented here. First, the fuel costs for 1995 were applied to the network system as described for 1997. This was done because 1995 was the latest year for which consistent cost data could be developed. These data would be expected to change somewhat during the 2-year lag, and to the extent that the positions of the generating units in a merit order dispatch would be misstated, distortions could be introduced. Second, the models executed here are instantaneous energy models, premised on a description of a network operating under hypothetical peak load conditions, whereas the cost data represent average annual costs. To the extent that average annual operating costs differ from those at peak, this approach introduces further uncertainty.

Ultimately, the power flow cases discussed below were constructed to examine significant interregional transfers of power and their effects. Relative differences in regional marginal costs drive the model's efforts to transfer power. Of the capacity for which costs have been supplied, the vast majority is either coal or nuclear baseload, whose operating costs tend to be both relatively inexpensive and stable. The interregional distribution of this baseload capacity is the factor that leads to trade. The calculated marginal costs obtained for the cases described below are instructive, but they are not critical to the analysis.

To check that the model approximates the actual network, it was solved with the configuration of generation and loads reported on Form FERC 715. The historical configuration so reported was a feasible solution for the network. The line flows calculated by the model were very close to those reported to the Federal Energy Regulatory Commission (FERC). Although the absolute percentage errors were as high as 96 percent, all but 60 of the 14,282 lines were within 10 percent. The average absolute percentage error across all lines was 0.1 percent.

Cases Considered

Power transmission depends on generator availability and on the level and location of demand. Except for two nuclear units, the analysis in this paper assumes the generator availability shown in the Form FERC 715 file for the summer of 1997. Two large nuclear units, Millstone 2 and 3, were shut down at that time. They are now in service, and they are operable in this analysis for all cases

[21] The operating cost of a generator is calculated using the general formula $(a + bg + cg^2 + dg^3) \times$ unit fuel cost. The parameter a is a constant, and b represents a fuel use coefficient. In the formula, c and d are the curvature parameters and are assumed to be zero. The quantity in parentheses is the amount of fuel required to generate g kilowatthours of electricity. The product is the fuel cost for producing g kilowatthours of electricity. Capital costs and variable O&M costs are not included in the cost calculation. Capital costs were excluded because they are not expected to be included when generation services are bid into competitive markets. The variable O&M costs were excluded because they are small and it is difficult to obtain data for individual generators. Small fossil units may fall below the reporting threshold of Form FERC 1 and Form EIA-412. All costs are reported in nominal dollars. Because of these simplifying assumptions, especially with regard to the c and d coefficients, costs reported here are, presumably, low estimates.

[22] Ideally, it is desirable to have costs for every generator in the system.

[23] Form EIA-867 has recently been redesignated as Form EIA-860B.

except the FERC base case, representing normal supply conditions for the region.[24]

In order to capture the effects of demand levels, separate sets of cases were prepared. In the peak demand set, the demand levels reported on Form FERC 715 were accepted. A second set, referred to as the "shoulder" demand cases, was run at 80 percent of the peak demand. This pair of cases was designed to simulate reduced load levels that might be common in many off-peak hours. The geographical distribution of demand was not changed from the original Form FERC 715.

The other major variable that was analyzed is interregional trade. Two trade assumptions are contrasted in the reference and "super region" cases. In the reference case, trade is assumed to be fixed at the Form FERC 715 levels and does not respond to price differentials between regions. Within the regions, power flows are "optimized" to achieve a least-cost solution. In the super region cases, all profitable and physically viable trades are permissible as the model is again optimized, this time across all four NERC regions. In essence, these runs give an indication of the impacts of open access to transmission lines, such as changes in the flow of electricity when open access (as in FERC Orders 888 and 889) is assumed for the given configuration of supply and demand. The assumptions are summarized in Table 2.

Peak Demand Cases

Reference

In order to provide a forecast that represents current trading patterns, electricity flow is optimized within the individual regions of the network only (the FERC base and reference cases), and only those transactions specified on Form FERC 715 are permitted. The summer peak demands represent the utilities' estimates of the greatest demand they were likely to face at that time, based on past experience. These estimates are part of the basis for their preparations to avoid supply disruptions and maintain reliability. The trade levels in the FERC file are reasonable estimates of what they would plan to import and export during periods of high system stress. Although they do not represent actual operating data, they are a good basis for determining the price and flow impacts that might be attributed to transmission congestion.

Super Region

This case is intended to show the effects of open access to the transmission network by assuming that generators will be dispatched over broad electricity markets, thus promoting additional interregional trade. A hypothetical aggregation of NEPOOL, NYPP, MAAC, and ECAR is created, referred to as the "super region," as generation resources are dispatched to minimize cost over all four NERC regions. The specifications for this case are the same as those for the reference case, except that interregional trade is not restricted or fixed to the levels in the FERC filing. The power flows are optimized over all the regions simultaneously, yielding an efficient economic solution over the entire group of regions. This case shows the opportunities to reduce aggregate costs for all regions taken together, as well as likely trade patterns, subject to system constraints between and within regions.

Shoulder Demand Cases

Reference

This case is intended to capture market conditions that could exist at other than peak periods. The case represents trade patterns that might be present for a longer duration by portraying conditions that would prevail more frequently than just during the peak hour. In order to simulate those conditions, the demand levels in all four regions were reduced by 20 percent from those modeled in the reference case.[25] This level of demand was selected to be representative of average load levels

Table 2. Summary Description of Cases

		Peak Demand		Shoulder Demand	
Case Conditions	FERC Base Case	Reference	Super Region	Reference	Super Region
Demand Level	100 percent	100 percent	100 percent	80 percent	80 percent
Optimization Boundaries	Within NERC Regions	Within NERC Regions	Across NERC Regions	Within NERC Regions	Across NERC Regions
Trade Conditions	Constrained	Constrained	Free	Constrained	Free
Added Capacity	None	Millstone 2 and 3	Millstone 2 and 3	Millstone 2 and 3	Millstone 2 and 3

Source: Office of Integrated Analysis and Forecasting.

[24]The Millstone units were shut down by the U.S. Nuclear Regulatory Commission in 1996 because of design configuration issues and safety concerns. Units 2 and 3 returned to service in 1998.

[25]The 20-percent reduction results in loads of 38,169 megawatts in MAAC and 17,089 megawatts in NEPOOL. Load duration data reported by the two independent system operators indicate that median (4,380th greatest) hourly load for 1999 was 29,319 megawatts in MAAC and 13,532 megawatts in NEPOOL.

during off-peak periods.[26] As in the reference case, costs are minimized within regions, and only base transactions are permitted across regions.

Super Region

This case is the same as the reference case except that the power flow solution is optimized over the entire group of regions.

Marginal Cost Results

Summary results for the five analysis cases are presented in Table 3.[27] NEPOOL, a high-cost region, reduces its dispatch and imports additional power in both super region cases; these imports increase as demand is reduced. Exchanges of electricity increase among the other regions as well. However, the transmission system limits power flows into the NEPOOL region in both the shoulder demand and peak demand cases. With the introduction of trade, the differences in marginal costs[28] between regions were reduced but not eliminated entirely, indicating the existence of a transmission constraint. The loadings of individual transmission lines change very little across the cases analyzed, as critical lines are already constrained and remain so. Total exchanges of power increase when the dispatch is optimized over the super region area.

In the FERC base case, about 1,100 megawatts of generating capacity at Millstone is not available for dispatch. Power flows were optimized within regions using the scheduled transactions of trade between regions reported on Form FERC 715. As expected, the marginal cost in NEPOOL greatly exceeds that in NYPP (Table 4), because only about 620 megawatts are available for import into NEPOOL, and the cost of generating and transmitting power within the region is higher due to the reliance on relatively expensive oil-fired units. When the Millstone units are included (in the peak demand reference case), costs fall sharply in NEPOOL. In NYPP, however, costs increase slightly as Millstone's significant output causes the 620 megawatts of scheduled transactions to use more costly transmission routes into NEPOOL.

In the peak demand reference case, generation resources in each NERC region, now including Millstone in NEPOOL, are dispatched to serve load within the region. New York has the lowest marginal cost of $25.3 per megawatthour (Table 4), while MAAC has the highest cost of $44.1 per megawatthour. NEPOOL and ECAR, at $29.2 per megawatthour and $31.5 per megawatthour, respectively, occupy the mid-range. The peak hour represents unusually high demand, a condition that would limit the possibility of obtaining relief through the transmission system, no matter how efficient it might be otherwise.

MAAC has very high costs because its generating costs increase rapidly as requirements increase at the time of peak demand, to about 47 gigawatts. This characteristic for MAAC (and cost characteristics for the other regions) is illustrated in the normalized price duration curve, which shows the distribution of generating costs over increasing demand levels (Figure 2). At peak, MAAC demands 46,279 megawatts net, which is roughly 97 percent of its available capacity. Because of its export requirements, ECAR dispatches virtually all its capacity, of which the last unit costs $31.5 per megawatthour; thus, despite very low operating costs over most of the dispatch range, ECAR's costs climb rapidly as the last unit is dispatched. Aided by Canadian imports, both NYPP and NEPOOL avoid the costliest portions of their

Table 3. Summary Results for Five Analysis Cases

Summary Result	FERC Base Case	Peak Demand		Shoulder Demand	
		Reference	Super Region	Reference	Super Region
Hourly System Cost: NEPOOL, NYPP, MAAC, ECAR (Million 1995 Dollars)	2.529	2.529	2.519	1.858	1.856
Total Dispatch (Gigawatts)	165.162	165.174	165.192	131.743	131.817
NEPOOL Dispatch (Megawatts)	18,917	18,893	18,677	14,537	14,173
NEPOOL Imports (Megawatts)	622	622	861	622	995
Gross Interregional Trade (Megawatts)	8,540	8,540	8,737	8,120	11,980

Source: Office of Integrated Analysis and Forecasting, PowerWorld® model runs FERC BASE CASE.D022800, ADMINTRADEWMILL.D022800, FREETRADEWMILL.D041000, REFERENCE80.D042400, and FREETRADEWMILL80. D042400.

[26] Nationally, the average monthly demand in July and August 1997 was 16 percent higher than the average demand in the other months. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(1999/12) (Washington, DC, December 1999), Table 7.1.

[27] The engineering solution was validated by Dr. Tom Overbye, Professor of Electrical Engineering, University of Illinois. A few lines in NYPP exceeded their limits, a result attributed to several small generators that were reported to the FERC as being out of service.

[28] Marginal costs are computed using the average of the marginal costs at the buses in the transmission network. Detailed data are available upon request from Tom Leckey (202-586-9413, thomas.leckey@eia.doe.gov).

Table 4. Marginal and Average Cost, and Standard Deviation by NERC Region in Five Cases
(1995 Dollars per Megawatthour)

Region	FERC Base Case	Peak Demand		Shoulder Demand	
		Reference	Super Region	Reference	Super Region
Marginal Cost					
NEPOOL	37.4	29.2	29.2	24.0	24.0
NYPP	23.8	25.3	30.4	17.3	18.8
MAAC	43.6	44.1	35.5	16.1	15.7
ECAR	31.5	31.5	33.9	15.1	15.3
Super Region . . .	NA	NA	31.8	NA	19.4
Average Cost					
NEPOOL	18.8	17.2	17.1	14.7	12.0
NYPP	15.6	15.8	16.1	14.6	14.7
MAAC	16.8	17.2	16.8	15.9	15.9
ECAR	13.4	13.5	13.5	12.7	12.7
Standard Deviation					
NEPOOL	5.6	3.9	4.0	9.4	10.2
NYPP	6.2	5.6	10.6	3.0	3.2
MAAC	1.0	0.9	2.7	2.3	1.6
ECAR	0.7	0.7	1.6	0.2	0.2
Super Region . . .	NA	NA	6.4	NA	7.4

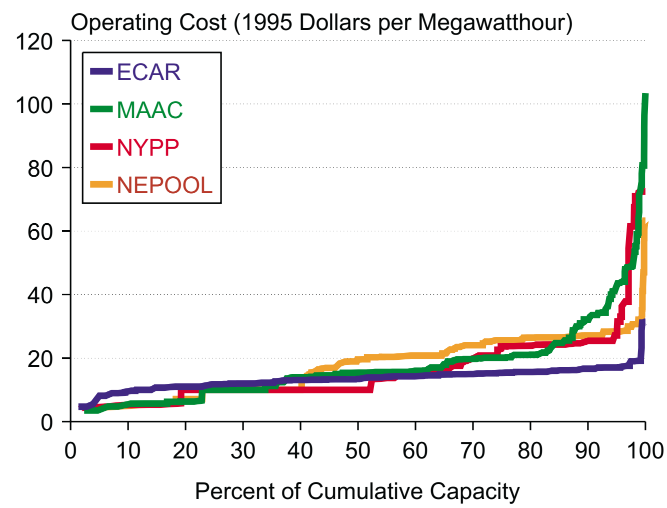
NA = not applicable.

Source: Office of Integrated Analysis and Forecasting, PowerWorld® model runs FERC BASE CASE.D022800, ADMINTRADEWMILL.D022800, FREETRADEWMILL.D041000, REFERENCE80.D042400, and FREETRADEWMILL80.D042400.

respective price duration curves. The variation in bus marginal costs within regions is indicated by the standard deviations in Table 4. Suggesting both the existence and impacts of congestion, higher standard deviation values indicate greater cost differences among the region's buses. Generally, the standard deviation of marginal costs at buses increases in the two super region cases.

These results can be summarized by use of a contour image, where color is used to portray different bus marginal costs over geographic areas. Contouring enables analysis of large amounts of data and shows areas of cost differences, if any, within regions. Figure 3 is a contour that shows the marginal costs for the buses modeled in the reference case.[29] The marginal cost at each bus is associated with a color identified in the legend on the figure. The high-cost areas are shown in red—principally in the MAAC region, where marginal cost runs in excess of $40 per megawatthour—and the lower costs are shown in green (as in NYPP).

Figure 2. Normalized Price Duration Curves in the Peak Demand Reference Case

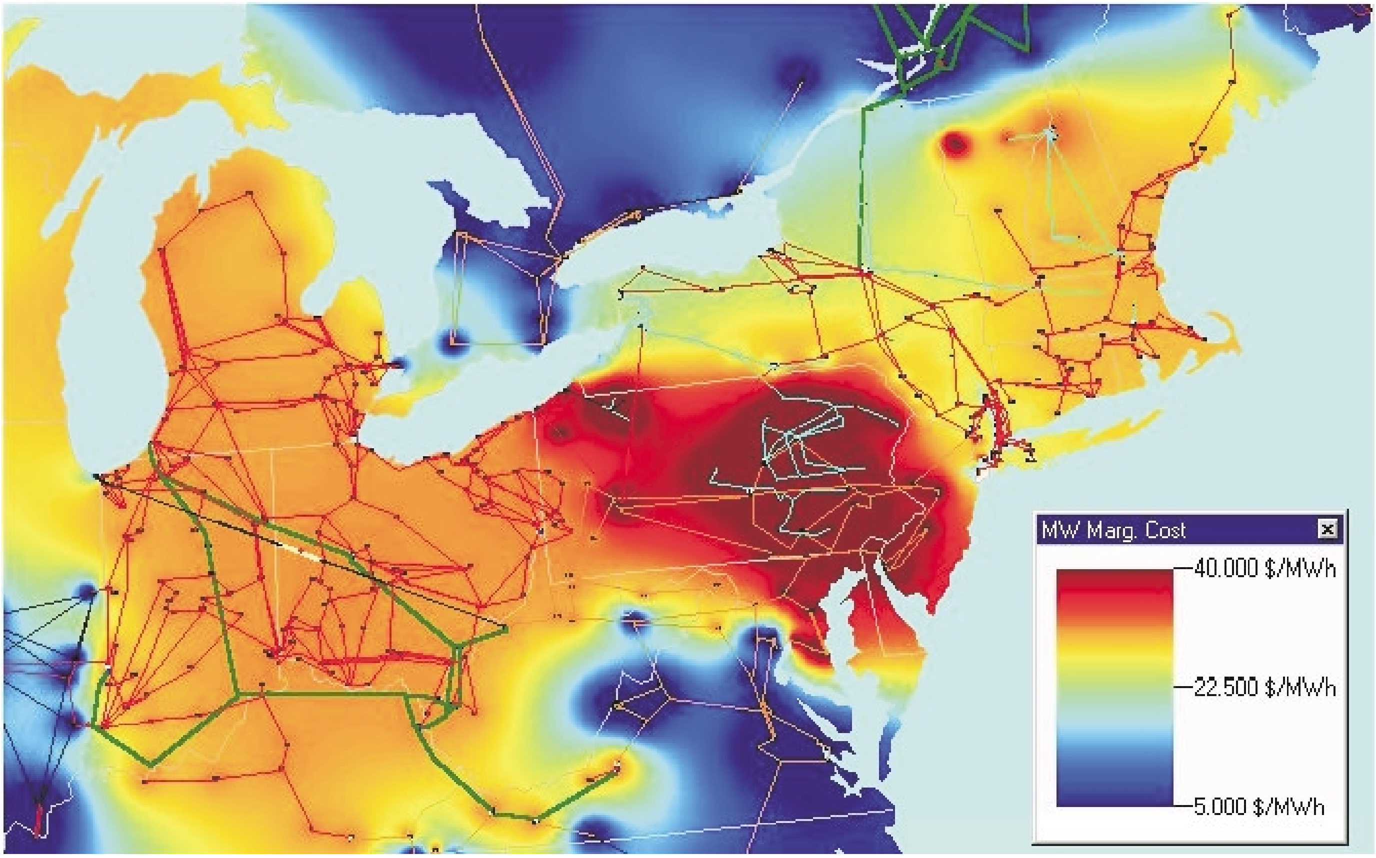


Source: FERC Form 1 and estimates presented in this paper.

The peak demand super region case reduces much of the variation in regional marginal costs and does not change the average costs significantly (Figure 4). The hourly system cost of serving load, which can be viewed as a measure of average costs, drops negligibly, by about 0.4 percent. However, there are larger changes in marginal costs specific to the regions. MAAC realizes the largest cost reduction while remaining the highest cost region at $35.5 per megawatthour (Table 4), and NEPOOL's marginal cost drops only slightly.[30] The marginal cost rises

[29]Some of the lower voltage buses are excluded from the contour.
[30]Marginal cost is reduced $0.05 per megawatthour, too small an increment to show as a reduction in Table 4.

Figure 3. Marginal Electricity Costs in the Peak Demand Reference Case



Source: Office of Integrated Analysis and Forecasting, PowerWorld® model run ADMINTRADEWMILL.D022800.

in both NYPP and ECAR compared with the reference case, as more expensive supply resources in those regions are called on to displace even higher cost units in MAAC. Interestingly, the marginal cost in NYPP exceeds the marginal cost in NEPOOL as a result of the optimization over the super region.

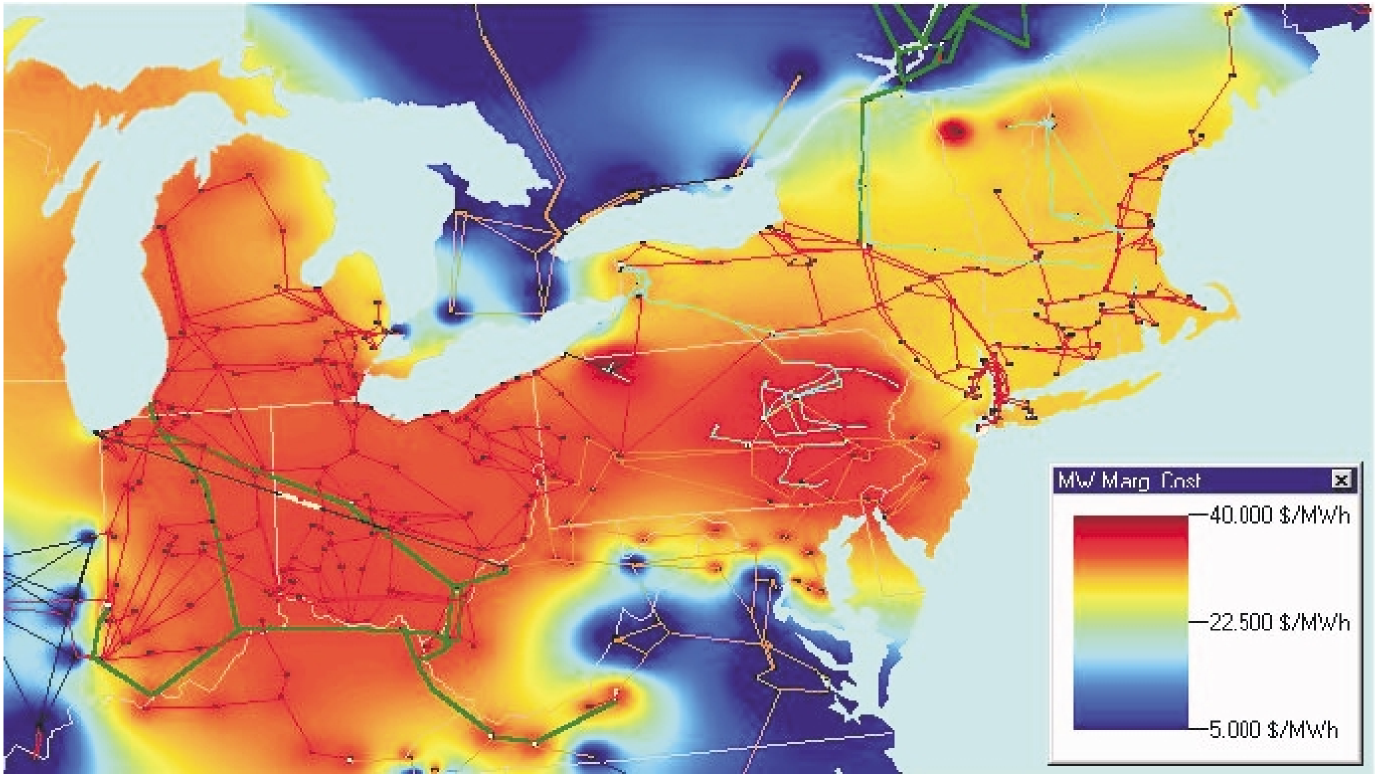
Interregional transfers of power are also different in the peak demand super region case compared with its reference case (Figure 5). ECAR, which is the lowest cost region generally, increases its export levels. In the peak demand super region case, ECAR exports 255 megawatts above the nearly 2,300 megawatts of power exported in the reference case. While both MAAC and NEPOOL import additional power, MAAC realizes greater volumes of imports because of its greater load requirements and its relative proximity to ECAR. NYPP reduces its net imports of power by about 900 megawatts, in part because of increased exports to NEPOOL but primarily because of higher exports to MAAC.

In both shoulder demand cases, costs fall in all four regions compared to the respective peak demand cases. The marginal cost in MAAC falls by nearly two-thirds and the cost in ECAR declines by about one-half compared with the peak demand cases. The benefits, however, are less in both NEPOOL and NYPP, indicating that congestion on the transmission system limits the amount of power that lower cost regions can provide. Marginal costs fall by 18 percent in NEPOOL and by about 32 percent in NYPP from their levels in the peak demand reference case. The difference between the costs in NEPOOL and NYPP increases when the optimization is done over the super region at the lower demand levels. As the marginal cost in NYPP falls nearly 40 percent from $30.4 per megawatthour to $18.8 per megawatthour, the marginal cost in NEPOOL holds steady at $24.0 per megawatthour.[31] However, the total hourly system cost in NEPOOL is reduced by 4 percent when super region trade is assumed.[32] Output from large generators serving the load centers of southern New England is replaced by less costly supply, but at the same time, several higher cost generators in Vermont are dispatched (Figures 4 and 5). This forces NEPOOL's marginal cost to rise even as the load centers in southern New England realize substantial benefits from trade.

[31]Of the four NERC regions at issue, only NEPOOL's marginal cost remains above that of the super region, the hypothetical aggregation of all four regions, which is $19.4 per megawatthour.

[32]The hourly system cost is a measure of all the operating costs of all the generators for a single hour.

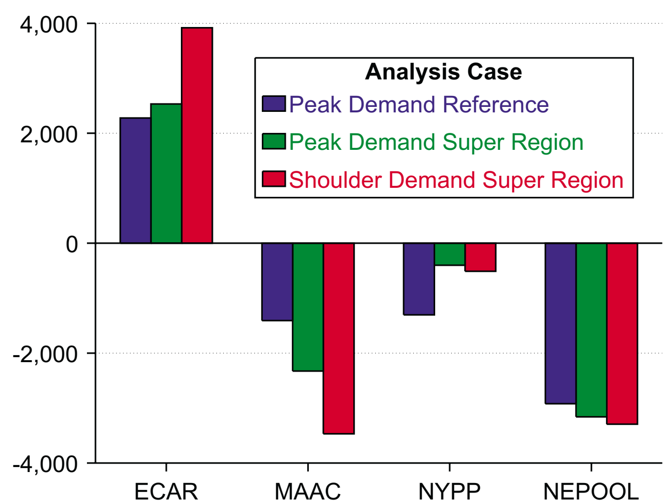
Figure 4. Marginal Electricity Costs in the Peak Demand Super Region Case



Source: Office of Integrated Analysis and Forecasting, PowerWorld® model run FREETRADEWMILL.D041000.

The introduction of trade in the shoulder demand super region case has negligible impacts on the hourly system cost over the entire super region.[33] Marginal costs are unchanged in NEPOOL and decline somewhat in MAAC while they increase in NYPP and ECAR (Table 4). This result indicates that benefits to consumers of interregional trade are relatively small during off-peak periods. Exports from NYPP to NEPOOL and MAAC increase by a total of 813 megawatts, greatly offsetting NYPP's base level imports of 1,304 megawatts.[34] Location in the transmission network allows generators in New York access to markets both north and south. This opportunity, however, comes at the expense of NYPP's own regional marginal cost, which increases in both super region trade cases (Table 4).

Figure 5. Projected Net Interregional Power Exchanges in the Northeast in Three Cases



Source: Office of Integrated Analysis and Forecasting, PowerWorld® model runs ADMINTRADEWMILL.D022800, FREETRADEWMILL.D041000, and FREETRADEWMILL80. D042400.

Tie Lines among Regions

An examination of the transmission tie lines between regions is useful in understanding trade patterns. In this analysis, New York is linked to NEPOOL by eight tie lines and to MAAC by 13 lines. MAAC is linked to ECAR by 21 tie lines.[35] Table 5 reports aggregate power

[33]System cost in the four NERC regions declines by 0.1 percent.

[34]Exports increase even more at the peak, to 936 megawatts. NYPP does not, however, become a net exporter under any of the trade scenarios. There are 800 megawatts of power imported from Hydro Quebec, specified as an exogenous input.

[35]Transactions with Canada are included at a fixed level based on Form FERC 715. In these cases, Canadian generators have no costs assigned and are not dispatched. They play no role in the optimal power flow solution.

Table 5. Interregional Gross and Net Tie Line Transactions
(Megawatts)

Interface	Peak Demand		Shoulder Demand	
	Reference	Super Region	Reference	Super Region
NEPOOL to NYPP	17	27	18	0
NYPP to NEPOOL	639	888	640	995
Net, NYPP to NEPOOL	622	861	622	995
NYPP to MAAC	1,040	1,261	994	1,012
MAAC to NYPP	2,158	1,684	1,997	1,691
Net, MAAC to NYPP	1,118	422	1,003	679
MAAC to ECAR	959	969	1,028	3,443
ECAR to MAAC	3,727	3,908	3,443	4,839
Net, ECAR to MAAC	2,768	2,939	2,415	3,900
Total Gross Transactions, Four NERC Regions	**8,540**	**8,737**	**8,120**	**11,980**

Source: Office of Integrated Analysis and Forecasting, PowerWorld® model runs ADMINTRADEWMILL.D022800, FREETRADEWMILL.D041000, REFERENCE80.D042400, and FREETRADEWMILL80.D042400.

volumes flowing through these interfaces in each of the four cases.

All of NEPOOL's domestic power imports come from NYPP. Imports by NEPOOL increase modestly in the peak demand super region case and more dramatically when there is additional capacity available off peak in the shoulder demand super region case. At the same time, NYPP is importing power from MAAC in all four cases (although imports drop in both super region cases), while MAAC in turn is importing from ECAR. Even small levels of imports from ECAR reduce MAAC's marginal cost dramatically,[36] but at the same time, MAAC exports to NYPP fall. Since NEPOOL's demands on NYPP remain substantial at both demand levels, this trade pattern contributes to the increase in NYPP's marginal cost in both super region cases.

An analysis of the affected tie lines illustrates the details of the transactions between NYPP and its trade partners, NEPOOL and MAAC. Although eight[37] tie lines connect NYPP to NEPOOL, about 62 percent of the imports flow over a single 345-kilovolt line located just north of New York City,[38] emphasizing the difficulty of delivering less expensive power to New England in the peak demand super region case. In the shoulder demand cases, the remaining tie lines into NEPOOL increase their share of power flow, while the 345-kilovolt Pleasant Valley line still carries about 47 percent of the imports in the shoulder demand super region case. Only one of the eight lines is fully loaded (Pleasant Valley is only loaded to 40 percent), as total unused transmission capacity is greater than 50 percent. Clearly, the NYPP-NEPOOL transmission interface itself does not constrain interregional trade.

In all cases, NEPOOL is a net consumer and ECAR is a net supplier of power, but the trade patterns between MAAC and NYPP are more variable. Under constrained trade conditions represented in the peak demand reference case, NYPP seeks cost relief by importing 2,158 megawatts from MAAC. At the same time, NYPP is exporting 1,040 megawatts to MAAC, mostly from two tie lines just west of New York City.[39] When regional trade is introduced in the peak demand super region case, the marginal cost in MAAC falls dramatically for several reasons: increased imports from ECAR; increased imports via the two previously mentioned tie lines with NYPP; and a reduction in net exports over the remaining tie lines with NYPP.

Interregional Power Flows Between NEPOOL and NYPP

The shoulder demand cases provide a means of examining the interregional power flows currently modeled in the EMM and comparing them with the flows modeled in PowerWorld®. The EMM models the NYPP-NEPOOL power flow interface through a single supply

[36]The first 43,000 megawatts of supply in MAAC are available at 33 mills per kilowatthour or less; the next 1,000 megawatts of load raises the cost to nearly 43 mills per kilowatthour.

[37]One of these, Norwalk Harbor 138, is reported as "open" on Form FERC 715 and is not available to the model. Interestingly, when this line is closed, the model indicates that low-cost NEPOOL generators in Southern Connecticut are able to supply NYPP with nearly 250 additional megawatts, thereby reducing the marginal cost in NYPP slightly, increasing the marginal cost in NEPOOL by 4 percent, and increasing the marginal cost over the entire super region from $19.4 to $19.7 per megawatthour. Source: Office of Integrated Analysis and Forecasting, PowerWorld® model run FREE80W8NPTIES.D061500.

[38]Pleasant Valley-Long Mountain 398.

[39]Much of this power comes from the nuclear units James Fitzpatrick and Nine Mile Point in western New York.

"pipeline," with options for six seasonal variations. The maximum capacity of this interface is 1,600 megawatts in all seasons.[40] In the *Annual Energy Outlook 2000* (*AEO2000*) reference case, imports of 11.6 billion kilowatthours in 1998 and 12.1 billion kilowatthours in 1999 flowed into NEPOOL via this supply route, using over 80 percent of the available capacity modeled.[41] EMM also allows imports of over 15 billion kilowatthours from Canada to NEPOOL in both 1998 and 1999.[42]

The super region shoulder demand case discussed earlier suggested that, despite prevailing differences in marginal cost between higher cost NEPOOL and lower cost NYPP, the transmission system was not able to reduce the price disparity between the two regions. Power flows to NEPOOL from NYPP did increase significantly under free trade conditions, from 622 megawatts to 995 megawatts, but the NEPOOL marginal cost remained about 28 percent higher than the NYPP marginal cost. Given this apparent constraint, how would NEMS model results differ under the import constraints implied by the PowerWorld® model runs?

To address this question, NEMS was run using the *AEO2000* reference case assumptions but modified so that NYPP transmission capability was reduced by 37.5 percent to 1,000 megawatts in all seasons, simulating the level of NYPP exports indicated by the shoulder demand super region case.[43] Under these constraints, NYPP exports to NEPOOL fall sharply from 12.1 billion kilowatthours to 8.1 billion kilowatthours (Table 6). Utilization of the supply pipeline increases sharply to over 90 percent. The energy component[44] of the NEPOOL competitive price across all sectors also increases by 2.3 percent in 1999 and by 3.1 percent in 2000. Most of the price components using a rate-of-return calculation show negligible change, because the capital and O&M components remain unchanged. The wholesale power cost component, however, falls by 9 percent, reflecting sharply reduced imports. Total fuel consumption for electricity generation increases by 7 percent, driven by a 12-percent increase in oil consumption. Imports from Canada are fixed at the same level as in the *AEO2000* reference case and remain unchanged.[45]

Data available from the New England independent system operator, ISO New England, Inc., provides another point of reference for both EMM and PowerWorld® simulations.[46] The direct current transmission line from Hydro Quebec, referred to as the "HQ interface," constitutes the primary source of Canadian imports to NEPOOL. Power flows at the HQ interface range between 1,600 megawatts and 2,000 megawatts and are

Table 6. Comparison of NEMS Reference and Restricted Import Cases: NEPOOL

Element (Model Year 1999)	*AEO2000* Reference Case	NEMS Reduced Import Case
Average Cost, All Sectors (1998 Cents per Kilowatthour)	10.1	10.1
Capital Component	4.6	4.6
Fuel Component	1.2	1.2
O&M Component	3.2	3.2
Wholesale Power Cost	1.1	1.0
Competitive Price, Energy Component (1998 Mills per Kilowatthour)		
Residential	37.5	38.4
Commercial	39.0	39.8
Industrial	37.4	38.2
All Sectors	37.9	38.8
Imports from NYPP (Billion Kilowatthours)	12.1	8.1
Total NEPOOL Generation (Billion Kilowatthours)	91.6	96.7
Petroleum-Fired Generation (Billion Kilowatthours)	18.3	21.9

Source: AEO2000 National Energy Modeling System runs AEO2K.D100199A and NENY.D050200C.

[40]The New York ISO reports the same available transmission capability for that interface. See web site http://mis.nyiso.com/public/htm/atc_ttc. NEPOOL ISO reports slightly more capacity.

[41]Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383(2000) (Washington, DC, December 1999), AEO2000 National Energy Modeling System run AEO2K.D100199A (reference case).

[42]The EMM allows for "economy trades" between NEPOOL and Canada, with opportunities for trade arising from cost differences, but the bulk of the imports in EMM are fixed "contract" trades.

[43]Imports in the shoulder demand super region case were 995 megawatts.

[44]The competitive pricing algorithm sums four components: reliability, tax, transmission and distribution, and energy.

[45]Thus simulating PowerWorld®, as NEPOOL turns to regional sources of generation.

[46]See web site www.iso-ne.com.

described as “relatively stable,” meaning there is not much hourly variation. The PowerWorld® cases model 1,600 megawatts of power input from this primary Canadian source,[47] and EMM’s annual Canadian imports of about 15 billion kilowatthours (energy) are basically consistent with the reported power flows.

Power flows from New York, however, behave differently in the *AEO2000* reference case and the PowerWorld® simulations. ISO New England estimates that total transmission capability for the NYPP interface varies between 1,300 megawatts and 2,100 megawatts,[48] putting the EMM’s pipeline capacity of 1,600 megawatts very close to the midpoint of the reported range.[49] ISO New England reports, however, that hourly power flows from NYPP fluctuate much more than the HQ interface, which indicates that actual power flows from NYPP may resemble more closely the power flows modeled in the super region cases and differ from those modeled in the EMM.

The New England ISO reports that for the 12-month period ending April 2000, total net interchange (NYPP and Canada) was 22.1 billion kilowatthours,[50] compared with 27 billion kilowatthours for EMM in 1999. Given the similarity in Canadian imports, the difference in power flows must be attributable to estimates for the NYPP interface. New England ISO does not report explicit historical flows from NYPP; however, using the total transmission capability, rough estimates of the utilization rates for both the Canadian and NYPP interfaces, and data for total net interchanges, an estimate for NYPP imports can be developed.[51] Ranging from 15 percent of total NEPOOL imports in March 2000 to 39 percent in May 1999, the estimated average over the 12-month period May 1999 to April 2000 is 28 percent of NEPOOL’s total annual net interchange. That rate of flow suggests annual energy imports of 6.5 billion kilowatthours from NYPP—about half the imports modeled in the *AEO2000* reference case and even less than the imports of 8.1 billion kilowatthours resulting from the NEMS restricted import case.

EMM transfers relatively large amounts of power from NYPP to NEPOOL, because the marginal cost difference between the two regions would suggest that it is economically beneficial to do so. The super region case modeled in PowerWorld® attempted to reduce total cost across the regions and the marginal cost disparity between NEPOOL and NYPP by increasing imports, just as EMM does. The PowerWorld® optimal solution, the least cost over the super region, supplied only modest power flows to New England, resulting in a higher marginal cost in NEPOOL. The significant cost disparities that persist between NYPP and NEPOOL,[52] coupled with underutilized transmission capability between regions, indicate a substantive intraregional transmission constraint more restrictive than the interregional capacity constraint modeled in EMM. As a result, EMM may forecast a lower competitive price of electricity in NEPOOL[53] and slightly lower oil and natural gas consumption in New England than would be the case if all the transmission constraints were present.

Evidence of Congestion

When optimal power flows are introduced in the super region case, the marginal cost in NYPP increases. This occurs, in part, because of the additional power needed to increase exports to both NEPOOL and MAAC. Some of the cost increase, however, is caused by congestion, the cost of moving power from generation to load through constrained systems. Table 4 shows one aspect of increasing congestion in the peak demand super region case—the increase in standard deviation of marginal cost at buses in NYPP—indicative of greater variation in marginal cost and an increasingly constrained system. This section considers the magnitude of congestion in the shoulder demand super region case and compares the findings with information reported recently by the New York independent system operator.

Table 7 shows the operating characteristics of the NYPP generators that respond to trade conditions by increasing their dispatch in the shoulder demand super region case. Three of these generators are located far to the north of the large load centers near New York City: a combined-cycle plant in Rennsselaer County and two coal facilities, one in Monroe County and another in Erie County near Buffalo. The wide geographic response indicates that the marginal cost of the generator plays a larger role in the dispatch decision than does the network location.

[47]Another 700 megawatts comes from New Brunswick through Maine.

[48]ISO New England, Inc., *Monthly Market Report* (May 1999), p. 20, Figure 17, web site www.iso-ne.com.

[49]See also web site http://mis.nyiso.com/public/pdf/atc_ttc/, where the New York ISO reports transmission capacity of 1,600 megawatts.

[50]See web site www.iso-ne.com/economic_and_load_forecasting/monthly_1999.txt.

[51]Estimated as total monthly net interchange less estimated Canadian monthly imports of 1.8 gigawatthours × 730. This yields an estimate for Canadian imports of 15,811 gigawatthours, basically consistent with the NEMS estimate.

[52]ISO New England, Inc., *Monthly Market Report* (February 2000), p. 6, Figure 3, web site www.iso-ne.com.

[53]Another possibility is that EMM yields a price for NEPOOL that is roughly consistent with power flow models but underestimates the NYPP price. PowerWorld® model runs that raised NYPP exports to 1,377 megawatts (the hourly equivalent of 12,060 gigawatthours of imports in the *AEO2000* reference case) produced negligible marginal cost reductions in NEPOOL but increased the marginal cost in NYPP by nearly 6 percent. Source: Office of Integrated Analysis and Forecasting, PowerWorld® model run REF80-HINYPPIMP.D061500.

The EMM models an unconstrained dispatch, sometimes metaphorically referred to as a “copper sheet,” where power is transmitted to load centers without constraint in a merit order dispatch until load is served.[54] The power flow cases modeled here can be analyzed in a fashion similar to EMM by arranging a merit order by operating costs, and then ascertaining the marginal unit in an unconstrained dispatch. Because unidentifiable units with default operating costs were present in every region, this analysis could not be done over all four NERC regions. In ECAR, virtually all the units were identified and had cost information developed using the primary methodology described earlier. In the peak demand reference case, ECAR serves 69,754 megawatts of native load, and an additional 2,277 megawatts of load outside ECAR, for a total net load of 72,031 megawatts. The optimal power flow solution, constrained by the transmission system, resulted in a marginal cost of $31.50 per megawatthour in ECAR (Table 4). The merit order unit that would serve the last megawatts of demand, however, has an operating cost of only $19.60 per megawatthour. That difference, $11.90 per megawatthour or 38 percent, is one indicator of the cost implications of modeling an unconstrained dispatch.

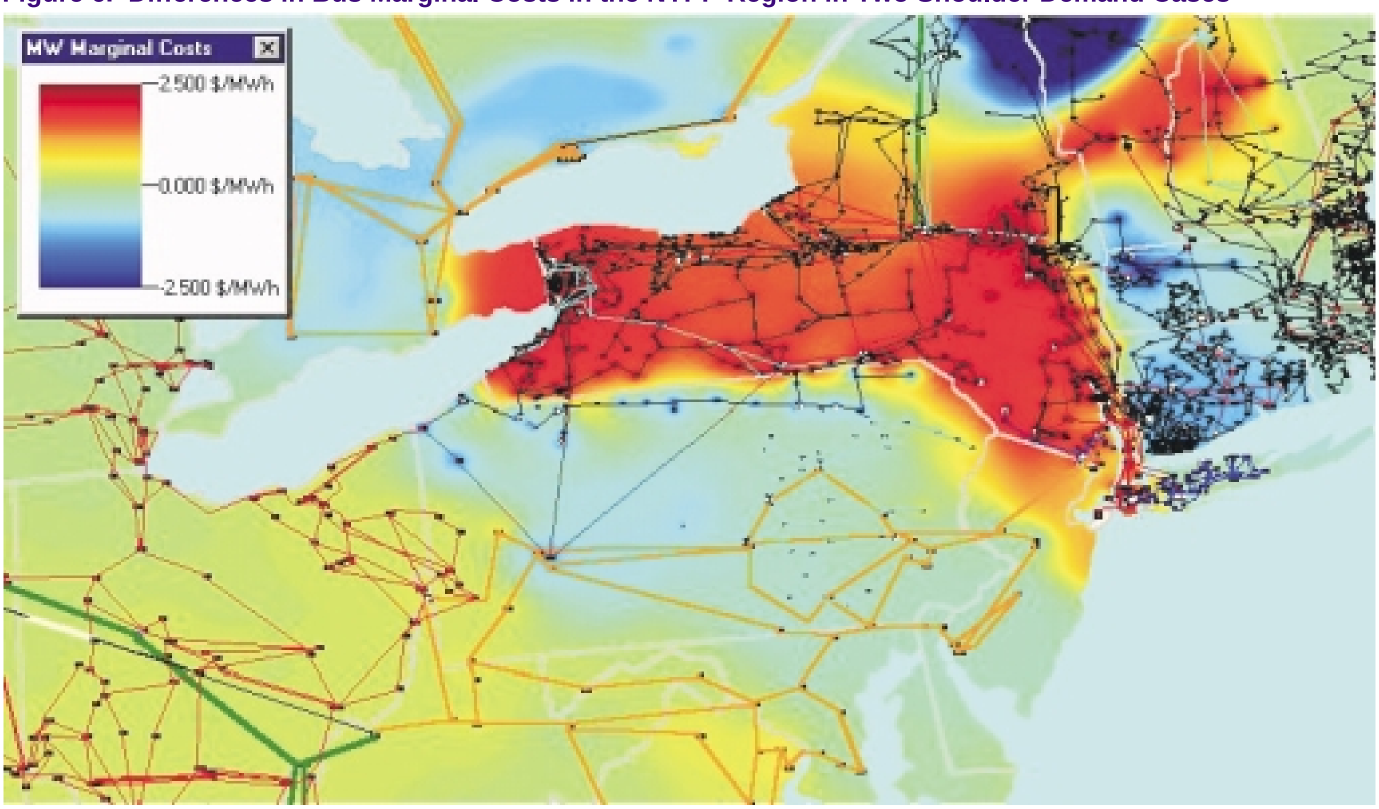
There are several ways to illustrate the impact of congestion. Figure 6 is a contour showing the differences in marginal costs at all 1,342 buses in NYPP for the

Table 7. Detail of Increased Dispatch at NYPP Plants in the Shoulder Demand Cases

Plant Name	County	Marginal Cost (1995 Mills per Kilowatthour)	Capacity (Megawatts)	Reference Case Dispatch (Megawatts)	Super Region Case Dispatch (Megawatts)	Additional Dispatch (Megawatts)	Fuel
Astoria	Queens	20.76	1,075	456	668	212	FO6/NG
LG&E-West	Rennsselaer	19.14	104	0	88	88	FO1/NG
Arthur Kill	Richmond	17.61	826	570	783	213	FO6/NG
C R Huntley	Erie	15.85	710	125	423	298	BIT
Rochester 7	Monroe	15.75	260	30	193	163	BIT

Source: AEO2000 National Energy Modeling System runs AEO2K.D100199A and NENY.D050200C.

Figure 6. Differences in Bus Marginal Costs in the NYPP Region in Two Shoulder Demand Cases



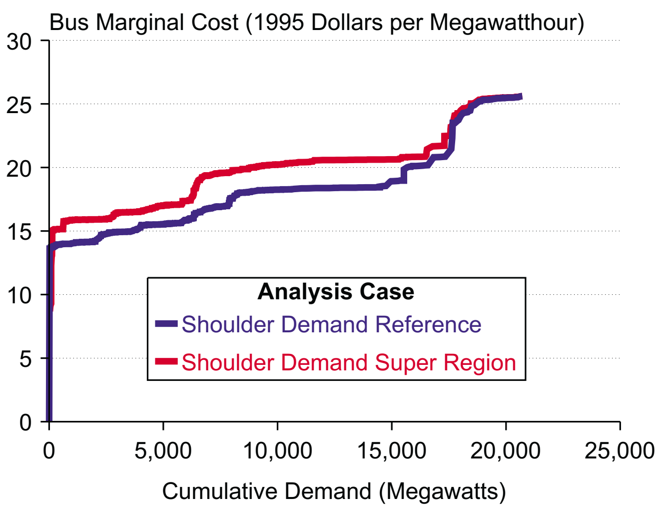
Source: Office of Integrated Analysis and Forecasting, PowerWorld® model runs REFERENCE80.D042400 and FREETRADEWMILL80.D042400.

[54]Losses are reflected as increased generation.

shoulder demand cases. Higher costs, indicated by red and orange shades, are evident at virtually every bus in the NYPP system, despite the fact that optimization requires that only a handful of generators respond with only a small amount of increased generation (Table 7). Reduced marginal costs, depicted by increasingly blue shades, occur in MAAC and Southern New England, while ECAR shows signs of modest congestion. The contour shows that congestion, the increasing cost of transmitting power, is not necessarily associated with the geographic interface at issue but rather accumulates over long distances in the general direction of the higher cost load.

The congestion pattern described in Figure 6 is not adjusted for the amount of load at the buses. Therefore, although congestion in NYPP appears to be widespread, the contour itself does not provide information about the cost impacts. In order to examine the cost effects of this congestion, a load-weighted distribution was constructed for NYPP using the 657 load-bearing buses in the region and comparing marginal costs in the two shoulder demand cases (Figure 7). Cumulative load appears on the *x*-axis. Approximately 20,700 megawatts are dispatched in NYPP in both cases. The far left points on the super region curve, showing some dramatic benefits from trade, bear virtually no load, and these are far outweighed by the significantly higher costs evident through about 18,000 megawatts of dispatch. After about 18,000 megawatts, the cost curves roughly converge, congestion dissipates, and the network imposes little or no additional cost. The net difference in the area between the two curves represents the costs associated with congestion in these cases.

Figure 7. Comparison of Congestion Effects in the NYPP Region in Two Shoulder Demand Cases



Source: Office of Integrated Analysis and Forecasting, PowerWorld® model runs REFERENCE80.D042400 and FREETRADEWMILL80.D042400.

Conclusions and Implications for NEMS

The modeling cases developed in this study indicate that the transmission system is capable of producing modest cost benefits, but that certain bottlenecks prevent all regions from benefiting to the same extent. At peak, the system is already heavily constrained, so that only one NERC region, MAAC, realizes lower costs when the peak case is optimized across all regions by loosening trade constraints. During shoulder demand periods, optimization over the regions indicates significant congestion in NYPP and NEPOOL, preventing New England from receiving power supplies sufficient to reduce the marginal cost there. Unlike the other three NERC regions studied in this analysis, NEPOOL, whose average cost lies in the middle range in the reference peak demand case, shows average costs that are consistently well above the average cost for the super region, even under the most favorable conditions modeled.

In several ways, the interregional electricity trade in this analysis is consistent with that produced by NEMS. In both models, ECAR, with large amounts of coal-fired generation, is a large exporter of power, and MAAC is a large net importer of power. NYPP shifts from a net exporter to a net importer over the years 1997-2000, as the region displays both the supply and the consumption characteristics modeled in the various PowerWorld® cases.

PowerWorld®, however, does not allow NEPOOL to import as much power as NEMS. Constrained by the network configurations specified on Form FERC 715, it is not cost-effective to import power to the extent that NEMS, which is a more aggregated model, does due to its assumption of unimpeded transmission flow within its regions. Moreover, total transmission capability, or a lack thereof, does not appear to be the driving constraint in optimal power flows as it is in NEMS. Even when PowerWorld® increases NEPOOL imports by nearly 60 percent in the shoulder demand super region case, utilization does not exceed 50 percent of the transmission capacity indicated by the Form FERC 715 data, because widespread congestion in the NYPP system prevents greater imports to NEPOOL. The question arises as to whether congestion plays a similar role in other NERC regions not included in this analysis.

Representing congestion and its costs directly within the EMM would be difficult to incorporate from a modeling perspective. The effects of congestion, one of which is restricted interregional trade between NYPP and NEPOOL, could be introduced indirectly into the EMM by incorporating the patterns and magnitude of interregional trade indicated by the PowerWorld® model through calibration. However, additional analysis is needed prior to pursuing the larger issues of representing congestion, voltage requirements, must-run units, and other ancillary products in EMM. The first step is expanding the number of regions in PowerWorld®. Because the regions analyzed in this study are affected by the rest of the Eastern Interconnection, the analysis should be expanded to include the Southeastern Electric Reliability Council (SERC), the Florida Reliability Coordinating Council (FRCC), the Southwest Power Pool (SPP), the Mid-America Interconnected Network, Inc. (MAIN), and the Mid-Continent Area Power Pool (MAPP). The larger area would provide a more complete analysis of the opportunities for electricity trade and the potential benefits to consumers than does the smaller area of coverage currently analyzed. Because this level of regional analysis provides a more comprehensive portrayal of the markets for electric power trade, it would result in findings with higher confidence levels with respect to interregional power flows.