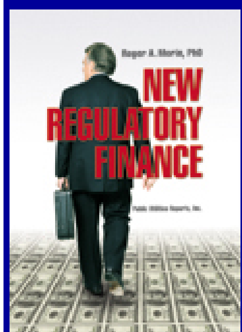

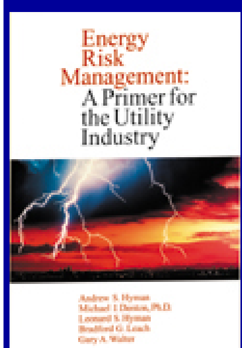

Transmission Planning: Weighing Effects on Congestion Costs

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Planners should focus on more than just meeting NERC reliability standards.

The Federal Energy Regulatory Commission (FERC) envisions a future U. S. electricity industry that will include large organizations to plan and expand regional transmission systems on a broad scale. This shift - from individual utilities seeking to meet the needs of their customers, to regional transmission organizations (RTOs) planning to meets the needs of markets - raises important issues:

1. The Planning Objective (reliability vs. commerce)
2. Alternative Investments (adding local generation or reducing load).
3. Effects on Land Use.
4. New Technology (new solid-state technologies permit operation of transmission systems closer to thermal limits).
5. Elusive Data (uncertainty over future load growth and power plant construction makes it difficult to estimate costs and benefits).
6. Congestion Costs (their role in deciding which projects to build).

At the same time, however, transmission expansion has failed to keep pace with changes in electric markets. The historical record shows a clear and long-term decline in United States transmission adequacy.[1] Specifically, the amounts of new transmission added during the past two decades have consistently lagged growth in peak demand. To make matters worse, projections for the next five and ten years show continued declines in adequacy.

Consider this: transmission owners and independent system operators are receiving so many requests for generator interconnections that they have little time for true planning. Instead, they focus primarily on preparing the system-impact and facility studies required for these new interconnections. Many transmission plans today are little more than compilations of individual generator-interconnection studies.

To make matters worse, little information is being developed on how the cost and location of grid congestion affects energy markets. Yet such information clearly is useful. In competitive electricity markets, with generation separated from transmission and system control, congestion pricing can offer valuable information on the potential benefits of new transmission investment. It can help potential investors decide where to locate new power plant units. It also can help load-serving entities decide what kinds of dynamic pricing and load-reduction programs to offer customers in different locations.

As Harvard University professor William Hogan has said, "In the long-run, investment in the grid is undertaken when customers find it economic to reduce these congestion costs and the cost of losses. In this sense, evolution of the grid would be determined by the market. ... [S]ecurity in the long-run is priced and provided through the market for long-run investments to increase generation and transmission adequacy.".[2]

This process occurred naturally under traditional regulation, when vertically integrated utilities coordinated their transmission and generation planning and operations and recognized any changes in costs for generation redispatch that occurred in real-time operations as part of the process of mitigating congestion.

By contrast, the FERC in its Order 2000 has emphasized that RTOs should conduct transmission planning, and that the process should "rely upon market signals and market solutions in assessing all feasible options (e.g., construction of new generation, redispatch of existing generation, as well as expansion of the transmission grid) to assure that the least costly option is pursued.".[3]

Some data are available on congestion cost. For example, Gale, Graves, and Clapp estimate year-2000 congestion costs at $800 million for the transmission customers in New England, New York, PJM, and California..[4] Congestion costs on California's Path 15 alone were as much as $169 million for the last four months of 2000..[5]

Nevertheless, the decision on whether to build new transmission remains complicated because of uncertainty over future costs and market conditions. These uncertainties relate to load growth, the price responsiveness of load, fuel costs and therefore electricity prices, additions and retirements of generating capacity, and the locations of those generators.

It is true that transmission investment totals only about 10 percent of generation investment. Transmission operating costs also run far below the magnitude of generation operating costs. Yet it would be far too expensive to build a transmission system that never was congested.

These facts lead naturally to basic questions: Do historical costs of grid congestion form a suitable basis for deciding on transmission investments? Further, should planners rely on costs reflected both in short-term nodal or zonal congestion prices, as well as long-term firm transmission rights?

An Example: Expanding Grid Links Between Regions

We developed a simple hypothetical example to explore these issues and their complexities and interactions. It consists of two regions connected by a single transmission line. In reality, transmission networks contain many lines and nodes; generators and loads are distributed throughout the network at many nodes. Nevertheless, this example illustrates important points about the role of congestion costs in transmission planning.

This example involves two regions, A and B, separated by 200 miles. Region

A contains 31 gigawatts (GW) of generating capacity and no load. Region B contains 32 GW of generating capacity and 50 GW of load. Both regions contain a wide range of generating capacity, with running costs (or bids) that vary from zero to almost $160/MWh. (Top of Fig. 1) The load in Region B ranges from 20 to 50 GW, with a load factor of 63 percent. (Bottom of Fig. 1) Loads exceed 45 GW only 1 percent of the time.

We calculated the cost of congestion as the difference between (1) the cost of generation (including generators in both regions) to serve the load in Region B when transmission capacity between the two regions is limited, and (2) the cost of generation when capacity between the two regions is infinite. The generation costs in both cases are calculated for every hour of the year using the load-duration curve shown in Fig. 1.

Fig. 2 shows the cost of congestion as a function of the amount of transmission capacity connecting the two regions. With 21 GW of transmission capacity (the baseline in this example), electricity consumers in Region B pay $87 million a year because of congestion. As the amount of transmission capacity increases, the cost of congestion declines because the number of hours that congestion occurs and the price differences between A and B decline. However, as shown in Fig. 2, this decline is highly nonlinear, with each increment of transmission capacity providing less and less economic benefit. Expanding transmission capacity from 20 to 21 GW lowers the cost of congestion $99 million/year, expanding capacity from 21 to 22 GW saves $44 million, and expanding capacity from 22 to 23 GW cuts costs by only $29 million.

How much would it cost to build additional transmission lines between regions A and B to reduce the costs of congestion? The cost of new transmission lines, including the necessary substations, increases with increasing voltage. (Table 1). However, the cost per GW-mile of new capacity declines, demonstrating substantial economies of scale.

Although it is cheaper to build larger lines, the lumpiness of transmission investments (e.g., one can build a 345-kV line or a 500-kV line, but not a 410-kV line) complicates decisions on whether, and by how much, to expand capacity. As a consequence, the relationship between the benefits of adding transmission capacity (reduction in congestion costs) and the costs of doing so are highly nonlinear (Fig. 3). (We assume a fixed-charge rate of 15 percent to convert initial costs to annual costs.) For this example, if the goal is to increase capacity by 0.5 GW, it makes sense to build either two 230-kV lines or one 345-KV line, but not a 500-kV line. On the other hand, it is most cost effective to use 500-kV lines when expanding capacity by 1 GW or more. Indeed, the benefit/cost ratio for 230-kV lines increases in going from an addition of 0.5 to 1.0 GW, but then declines as more capacity is added. On the other hand, the benefit/cost ratio is more than two for the addition of a 500-kV line to expand capacity by 1.5 or 2.0 GW.

The Complications: Allowing for Market Growth

What happens to these costs and benefits if additional generating capacity is built in Region B, close to the load center? Adding 0.5 GW of capacity, with a running cost of $30/MWh, reduces congestion costs by $19 million/year. Adding 2 GW of such capacity reduces congestion costs by $59 million/year. If the new generating capacity added to Region B had a running cost of $57/MWh, its congestion-reduction benefits would be only $14 and $35 million/year for 0.5- and 2-GW additions, respectively. These benefits are about two-thirds of those that would occur with new capacity at $30/MWh. Clearly, building new generation in Region B would undermine the economics of adding transmission capacity between regions A and B. And, the cheaper the new generators in Region B are, the greater their effect will be on lowering congestion costs.

In addition, the congestion-reduction benefits of each additional MW of generating capacity are less than the benefits of earlier additions (Fig. 4). This effect especially is pronounced as the bid prices of the new units increase. For the more expensive of the two units shown in Fig. 4, there is no benefit from adding more than 1.5 GW of generating capacity in Region B because other generators are less expensive. Once again, the results are highly nonlinear.

What if loads increase in region B? If loads grow at 2 percent a year, the annual cost of congestion (assuming no additions to either generating or transmission capacity) increases from $87 million in the initial year to $125, $162, and $250 million in the second, third, and fourth years. Such increases in load make transmission investments substantially more cost-effective.

If loads respond to prices, so that loads are higher at low prices and lower at high prices, congestion costs would be reduced. In this example, as the price elasticity of demand increases from 0 to 0.02, 0.04, and 0.08, congestion costs are reduced from $87 million to $48 million, $25 million, and $7 million a year. Figure 5 summarizes the effects of changes in load and load shape (induced by customer responses to price changes) on annual congestion costs. For the ranges considered here, congestion costs vary tremendously, from $7 million to $250 million a year, when the amount of transmission capacity between the two regions is 21 GW. Making decisions on how much money to invest in equipment with lifetimes of several decades is difficult in the face of such uncertainties about future load growth; customer response to dynamic pricing; and the amounts, locations, and running costs of new generating units.

Consider the situation in which 500 MW of $30/MWh generation has been added in Region B and consumers respond to price changes with an elasticity of 0.01. In this case, the annual cost of congestion when transmission capacity between A and B is 21 GW is $41 million, less than half the basecase value. The benefit/cost ratios shown in Fig. 3 are all cut by more than 50 percent. The only cost-effective project under these conditions is the construction of a single 500-kV line to provide an additional 2 GW of transmission capacity. Thus, changes in generation and load can affect the value of transmission, increasing risks to transmission owners.

The discussion so far has focused on the benefits of reducing congestion. But not all market participants benefit when additional transmission is built to relieve congestion. In particular, loads on the low-cost side of the constraint and generators on the high-cost side of the constraint lose money when congestion is reduced. For example, a generator in Region B with a bid price of $42/MWh would earn $6.9/kW-year when the transmission capacity between regions A and B is 20 GW. Expanding transmission capacity to 21 or 22 GW would reduce that generator's earnings to $4.6 and $3.7/kW-year, reductions of 33 percent and 46 percent, respectively. Such large prospective losses likely would engender substantial opposition to efforts, either transmission or nontransmission, to reduce congestion. If Region A had loads that enjoyed the benefits of Region A's low-cost generation, those loads also would oppose efforts to reduce congestion.

Finally, investors considering additional generation in Region B may worry that future construction of a new transmission line between A and B would undercut the value of their new generation.

What the Data Implies: Some Suggestions for Planning

Transmission planning today may be too narrowly focused on planning standards developed by the North American Electric Reliability Council (NERC). That is, transmission planning may pay insufficient attention to the benefits new transmission investments might offer competitive energy markets, in particular, broader geographic scope of these markets and a reduction in the opportunities for individual generators to exercise market power. As NERC has noted, "A robust, reliable transmission system is needed to develop a competitive market and to achieve its full benefits.".[7] Although some plans consider congestion (either congestion costs or curtailments and denial of service), such considerations are more implicit than explicit. As discussed here, congestion costs can provide valuable information on where and what to build.

The example developed here shows that:

- Congestion costs are a complicated function of the amounts, costs, and locations of generation; the time-varying patterns and locations of electrical loads; and the configuration of the transmission system.
- Congestion costs can be reduced by adding transmission facilities, by suitably locating new generating units, or by modifying electricity demand at the right times and places.
- These congestion-cost-reduction strategies all show diminishing marginal returns. That is, the incremental benefits of additional generation, transmission, or load reduction decline.
- In addition, these congestion-cost-reduction strategies interact with each other. Adding generation on the "downstream" side of a constrained interface reduces the benefits associated with transmission expansion or load-reduction programs. Similarly, building new transmission facilities or implementing load-management programs reduces the benefits of building generation close to load centers.
- Not all market participants benefit from reductions in congestion costs. In particular, loads on the upstream side and generators on the downstream side of a congested interface will lose money if congestion is relieved.

These results complicate the use of historical data on congestion costs in planning new transmission facilities. Nevertheless, such historical data provide valuable information on the potential benefits of new transmission projects and should be used more extensively in transmission planning.

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