**How Much Transmission Do We Need? How Do We Know? And Who Should Pay?
Thinking Twice About Transmission And Its Alternatives**

NEDRI Discussion Memorandum
Richard Cowart Draft 1 - May 28, 2002

(A) Introduction
Electric transmission policies have traditionally been a low-profile topic even among electric utility executives and utility regulators; and environmental professionals rarely had cause to be concerned about them, except in the rare transmission siting case. That world has changed dramatically. Transmission decisions are now critically related to the nature of regional electricity markets, the environmental footprint of the electric industry, and to the future of distributed resources, including demand-side resources. Since the passage of the EPACT in 1992, the FERC has been engaged in a series of complex open-access and regional market initiatives that greatly change the role of transmission in the electric system. Transmission is no longer just an implementation tool for utilities to deliver power within integrated franchises, but is an avenue of commerce to connect multiple generators to multiple load centers, often at great geographic distance.

In its recently-released National Transmission Grid Study (NTGS), the DOE concludes that transmission constraints increase electricity costs and decrease electric system reliability to consumers in many regions of the country. The study identifies a number of policies that could promote investments in new transmission facilities, but also notes that demand-side options can play an equally important role in delaying or avoiding the need for those investments:

> Enabling customers to reduce load on the transmission system through voluntary load reduction or through targeted energy efficiency and reliance on distributed generation are important but currently underutilized approaches that could do much to address transmission bottlenecks today and delay the need for new transmission facilities.[1]

The NTGS includes several recommendations to support demand management, price-responsive load, and energy efficiency programs.[2] Since transmission operations and planning are done on a

[1]NTGS p.41.

[2]Including many of the topics under discussion within NEDRI -- demand-side bidding, price-responsive load, advanced metering, demand-side participation in ancillary service markets, increased support for energy efficiency programs, and regulatory policies to eliminate utility disincentives to efficiency and distributed generation. NTGS

regional basis, the Study points out that "opportunities for customers to reduce their electrical demand voluntarily, and targeted energy-efficiency and distributed generation, should be coordinated within regional markets," and concludes that regional planning processes "must consider *transmission and non-transmission alternatives* when trying to eliminate bottlenecks."[3]

These aspects of the NTGS echo and expand upon the positions announced by FERC in recent RTO orders and reviews. In several recent orders, FERC has made clear its view that transmission planning, transmission adequacy, and transmission pricing are to be the responsibility of the nation's newly-emerging Regional Transmission Organizations[4]. Thus, planning and expansion activities that have historically been conducted within state-regulated franchise utilities are now being taken up by RTOs -- entities with virtually no experience with retail ratemaking, energy efficiency programs, distributed generation, or demand management.

This has created a situation characterized by several serious tensions:

1. **Whose authority?**-- FERC, regional entities, or states? RTOs increasingly are given responsibility to resolve transmission constraints, but the expertise in demand management, pricing, and power line siting lies with retail jurisdictions. How should the planning and expansion process be organized to deal with this mismatch?
2. **What mechanisms?** Private markets, public goods, or both?
3. **What investments?** Wires-side, demand-side, or both?

On the positive side, transmission expansion may enable large regional markets to clear at lower prices and serve load more reliably. On the negative side, there is a mismatch between the operation of ***markets*** for generation and consumption, and the operation of ***monopoly wires systems*** for the delivery function, and both the market effects and the environmental effects of this mismatch may be very large. Transmission planning, pricing, and expansion policies will cast a big shadow in the coming decade.

Many current proposals before Congress, FERC, state PUCs, and regional RTOs and grid operators call for affirmative actions to promote transmission solutions to energy service problems in a variety of ways: creating large RTOs and removing "pancaked" transmission tariffs within them; giving new eminent domain authority to regional and national agencies; awarding incentive rates of return for transmission investments; supporting independent transmission entrepreneurs; granting socialized and rolled-in tariff treatment for new facilities;

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pp 41-45.

[3]NTGS p. xiii (emphasis added).

[4] FERC states that responsibility for transmission adequacy and expansion planning is a required RTO function (Function 7).

and so on. In some instances, of course, transmission investments are needed and pro-transmission policies may be required. However, policymakers and other stakeholders should not conclude that the best answer to high prices, congestion, or reliability challenges will always be more transmission. On the one hand, public policies that lead to *underinvestment in transmission* can raise the cost of power, undermine cost-effective remote resources, and worsen reliability challenges. But public policies that lead to *overbuilt and mispriced transmission* may raise the cost of electric service, undermine cost-effective distributed resources, and worsen system environmental effects. Today's challenge is to find the right principles and procedures to support the appropriate level of investment in the grid, together with the

This memorandum is intended to begin a discussion on transmission expansion policies in today's markets by focusing attention on three topics:

- The different interpretations of "need" facing decision-makers in the transmission realm, particularly the difference between economic congestion and system reliability (Section B);
- The effects of different transmission pricing and cost recovery policies on competitive power markets, especially on the ability of load-center resources to compete on an equal basis with long-distance trades and remote generation assets (Section C); and
- Transmission planning policies, particularly the challenge of comparing transmission to non-transmission alternatives that could solve congestion problems (Section D).

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The memorandum closes with some initial suggestions for transmission policies and practices that should be considered in order to reveal the value of load-center resources, including demand-side responses, to regional power systems.

(B) How Much New Transmission Is Needed?

Any discussion of transmission expansion policies must begin with an honest understanding of the many ways in which "need" can be characterized -- and often, mis-characterized[5].

(1) Transmission is a service, not a final objective

As a starting point, it is important to understand that consumers do not directly consume (or desire) electric transmission any more than they consume or desire telephone poles. The delivery system is just an intermediate service needed to a greater or lesser extent to provide telephony or

[5]The problem is illustrated by the frequent use of highway metaphors to describe transmission systems. See, e.g., NTGS at xii. Aside from the significant physical differences between vehicular and electric transmission congestion, there are at least two major flaws in this analogy. First, demand-side and distributed generation alternatives to transmission are much more numerous, cost-effective, and more viable than the non-vehicular alternatives to highway use. Second, the nation's traditions of socializing highway costs cloud our thinking about transmission tariffs based on cost-causation, and about trade in privately-owned transmission rights.

electric service. Moreover, like telephone land lines, electric transmission is a service with substitutes. Electric load will require more or less transmission support depending on whether it is relying on power from large, remote power plants, or from local, load-center resources (which could include a combination of traditional generation, distributed generation, load management, and/or energy efficiency). Thus, determining "need" for transmission and building transmission facilities are processes with policy consequences at both ends of the wire. Over-investing in transmission will tend to support remote generation and undermine the value of distributed resources. Under-investing in transmission will have the opposite effect. These decisions may greatly affect the environmental profile of the industry and skew the market for electricity services at the same time.

(2) Thinking About Congestion: Economic Signal or Reliability Problem?

Many discussions of the need for transmission begin with observations about congestion, and "bottlenecks," which are said to arise "when there is not enough transmission capability to accommodate all requests to ship power over existing lines and maintain adequate safety margins for reliability."[6] When congestion occurs, system operators must deny some requests for transmission service to protect reliability margins. As the NTGS notes, in recent years the number of congestion events leading to such Transmission Loading Relief (TLR) "calls" has risen sharply.

Although some observers interpret the existence of congestion or TLR calls as proof in and of themselves that transmission expansions are needed, a more careful review is needed.

Particular attention needs to be paid to the meaning of congestion -- is congestion, like peak-period power prices, mainly an economic signal that can and should be addressed through individual market actions, or should congestion be viewed as a reliability problem that must be addressed by RTOs through investment in tariffed assets?

First, consider the situation where concentrated load relies upon remote generation, but cannot always be served fully from those remote resources -- a "load pocket." Many observers will argue that ***the existence of congestion*** demonstrates the need for relief in the form of expanded transmission. But, recognizing that transmission is a service with alternatives, one might with equal logic argue that the existence of congestion is proof that there has been inadequate investment in load-center resources (which could include local generation, load management, energy efficiency, and distributed generation.) How do we know which of these arguments is correct?

Second, proposals aimed at ***eliminating ALL congestion*** fail a simple test of economic efficiency. Trying to create a transmission system that never experiences congestion makes no

[6]NTGS p.6

more sense economically than trying to create an airline system that will never have a sold out flight, or a hotel district where every hotel always has available rooms. No one would suggest that such a system was societally efficient. So what is the ***efficient level of congestion***, and how can system planners know when it has been exceeded?

Third, transmission expansion proposals premised simply on an apparent ***increase in congestion*** may be comparing last year's oranges to this year's grapefruits, and assuming that the oranges have grown. Prior to restructuring and divestiture, vertically integrated utilities self-scheduled generation to meet customer needs, and took historic transmission limitations into account in doing so. Those decisions would not show up as TLR events. In today's more active wholesale markets, with many power plants now in the hands of third parties who do not own the wires, these same events could lead to an attempted trade that triggers a measurable TLR call.

Unfortunately, we must also be wary of calls for transmission enhancements based upon the supposed increase in demands for transmission service from energy marketers active in recent years. How many of these requests were associated with legitimate trades, and how many were associated with illusory trades, strategic gaming or manipulation by marketers? How much transmission congestion was real, and how much resulted from power market manipulation? At the present time, we just do not know.[7]

The distinction between impaired reliability and simple economic congestion is perhaps best illustrated in transmission analyses that take an active trading region and model an across-the-board reduction in load, as might occur in an economic recession, or as a result of widespread energy efficiency investments. Under these circumstances (reduced overall load), customers will see increased reserve margins, lower wholesale prices, and improved reliability. The effects on transmission, however, are likely to be minimal or rather mixed. In some hours and locations, congestion will be reduced, but in others, congestion can actually increase. With decreased sales in the local area, some power plant owners will seek to sell their output to remote markets[8]. Whenever some of these new long-distance transactions cannot be scheduled when desired, economic congestion arises. The system is more reliable, and new potential trades are now possible, but not all of those desired transaction can be scheduled. Is the grid in worse shape? Most people would not think so.

[7]The Enron trading strategies are of course the best-known. But Enron is not alone. Reliant Energy, said to be the nation's fifth largest trader, conceded that 20% of its reported trading volume in 2001 was in "round-trip" trades, intended to make the company's growth appear more dramatic to investors. CMS, Dynegy, and others have also been involved. Traders concede that many of these strategies were expressly organized to create congestion on transmission routes so as to drive up the market price of power in wholesale markets.

[8]This is consistent with the findings of the NTGS that congestion tends to be greatest during a power system's ramping hours, rather than at peak.

(C) Transmission pricing and cost recovery rules can skew economic outcomes

(1) Market effects of transmission decisions: Because transmission is a monopoly service, pricing and cost allocation are governed by regulation. How prices are set and costs are assigned will have very large effects on the market and on the environment -- magnified by the effects they have on decisions at both ends of the wires. Advocates for transmission expansions often argue that, since transmission only comprises about 10% of the total cost of delivered electricity, overinvesting in transmission assets is unlikely to have a major impact on the cost of electricity, and is therefore not a real concern[9]. While the significant sums involved are important in themselves, this observation ignores an even more important point: different transmission investment and pricing strategies will affect the relative market positions of remote generation, load-center generation, and demand-side resources. Transmission expansion and pricing policies will affect the markets *at both ends of the wire*, and thus can have an impact on the market far greater than the dollar cost of the wires involved.

For example, a decision to "socialize" the cost of transmission upgrades that will bring in remote generation will lower the *market cost* (but not the societal cost) of generation in some locations but not others, and will lower the *market value* (but not the societal value) of otherwise cost-effective local generation and efficiency investments. By tipping the balance among different resources and market participants, transmission pricing decisions can have very large impacts on the competitive positions of load-center and customer-based resources versus remote generation facilities. Different transmission policies may have the effect of promoting "coal by wire,"[10] combined cycle gas, or load management to a degree not anticipated by decision-makers. Efficient market outcomes will require careful thinking about transmission pricing and cost recovery rules.

Cost and equity issues are also large. According to EEI and NERC estimates, maintaining transmission adequacy at its current level through the next decade would require an investment of about $56 billion nationwide[11]. In New England, for example, grid planners are considering proposals to socialize about $120 million in transmission upgrades to relieve congestion in the Boston region, (making it easier to export gas-fired power from Maine into Massachusetts), and

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[9]While there is some modest appeal to this observation, at more than $20 Billion per year, the cost of transmission is certainly large enough to be of concern to regulators and other stakeholders. As a test, consider: How many transmission advocates would be persuaded by the parallel observation that since energy efficiency programs are typically even smaller (less than 2% of the cost of service), large increases in DSM spending should be supported even in the absence of cost-effectiveness analyses? How many consumer advocates would be persuaded by the same argument as applied to the return on equity?

[10]Nationwide, developers have announced at least 75 major coal plant proposals totaling more than 50,000 MW in potential new generating capacity, mostly in remote sites that will depend on favorable transmission treatment to get to market.

[11] ISO New England, "Opportunities and Challenges Facing the Electric Power Industry in New England" September 2001 at 7.

to socialize over $500 million of upgrade costs to improve flows into and out of Southwest Connecticut. Tariff and regulatory decisions of this type have rarely been subject to least-cost economic analysis[12], much less a review for their environmental effects.

(2) What investment signals do we want to send? Transmission expansion and support policies are often proposed to solve today's problem. For example, in the case noted above, there is presently a surplus of generation capacity in Maine, and a shortage in Boston -- so it is natural to think that building a transmission line between them is the right solution. And it may be, but it is important to ask "Who will be paying for this transmission? And what signals does this send to investors?"

As ISO-New England reported last September, since 1999 12 new power plants totaling 3600 MW have been built in the region. Up to 16 more plants are planned for the next two or three years, which could add another 7600 MW. As the ISO points out, "(t)hat's enough power to light up a major metropolitan area with 9.5 million homes."[13] However, the same report notes that congestion problems remain serious in both NEMA (Boston region) and Southwest Connecticut. Thus, investors in New England have added, and are adding, enough new generation to serve the congested regions – they are just not adding them IN those regions.

The rules adopted for transmission expansion will send important economic signals to customers and generators making investment decisions throughout the region. It's not a static world -- the rules we adopt will affect the location decisions of the NEXT generation of power plants, the next generation of load management investments, and the next generation of distributed resources. If investors learn that they can build large facilities in remote areas where land and fuel are cheap, and the pool will pay a substantial share of the cost of shipping their product to market, why should they pursue the harder work of locating facilities close to load? And, by contrast, if load-center resources have to bear all of their own costs, they will have a harder time competing against remote generation. In this manner, today's congestion relief policy may, ironically, actually promote future congestion[14].

(D) The Transmission Planning Process -- suggestions to reveal the value of wires, traditional generation, and distributed and demand-side resources

Rapidly-changing electricity markets, FERC and RTO initiatives, reliability concerns, and the

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[12] The RTEP process in New England is among the leaders in the US in approaching these issues. For example, ISO-NE reports note that the costs of congestion due to out-of-merit dispatch are even higher than the costs of transmission upgrades proposed to relieve the constraints. However, without a hard look at the *non-transmission alternatives* that could perhaps also relieve constraints, planners cannot determine if the transmission upgrade is the least-cost means of addressing the problem.
[13] Ibid, at 6.
[14] Perhaps here the highway metaphor is apt. This is how low-cost access to highway interchanges promotes new suburban shopping malls.

interests of generation investors in low-cost access to broad markets are all driving transmission expansion plans. However, the nation has precious little experience in transmission planning outside of the integrated franchise planning process, and a new framework needs to be developed, tested, and presented to decisionmakers. NEDRI participants should consider and discuss the following elements of a balanced regional transmission policy:

<u>(1) Transmission-Level Congestion Pricing</u>: Transmission prices that hide from customers the costs of congestion, and the value of congestion relief, diminish the reliability contribution that could be made cost-effectively by load management, efficiency, and generation in load pockets. FERC, RTOs, state regulators, and other stakeholders should support transmission rate designs that reveal the cost of congestion and the value of congestion relief across different times and locations. Locational Pricing reveals the cost of congestion and the value of congestion relief.

The preceding discussion of transmission systems and costs touches on two important features relevant to the role of demand resources: (a) Congestion on the transmission network can raise very important reliability problems, not just for the load centers directly affected, but potentially for customers across the entire affected network; and (b) Congestion on the transmission grid is not even across the network, and it varies with time. For these reasons, energy efficiency and load management resources may have great value when they reduce load in the particular locations and at the particular times that congestion problems would otherwise arise.

The application of locational pricing is an important step in the development of competitive electricity markets. When congestion costs are assigned to the responsible load, a more accurate price signal is received within the load pocket. Thus, cost-effective means to reduce congestion will have the opportunity to compete to reduce the congestion and improve reliability.[15] Generation, transmission, and load management options will all have the incentive and the opportunity to offer cheaper solutions to customers and load-serving entities within the load pocket. Because locational pricing sets an appropriate "price-to-beat" benchmark, replacing a system in which congestion costs are not revealed to customers, efficiency and load management investments can compete on a fair basis with transmission and generation options to provide reliability services in the load center.

<u>(2) The Efficient Reliability Standard</u>: RTOs, reliability managers, and transmission owners often seek cost recovery in FERC-approved tariffs for investments intended to enhance system reliability. New England should consider a screening tool for such proposals. Before

[15] Particularly if the Efficient Reliability Standard (discussed below) is applied to proposals that would socialize congestion relief and mute the signals sent by locational pricing. Locational pricing and the Efficient Reliability Standard work together to advance the most reliable and lowest cost solutions to congestion problems.

granting recovery that would broadly "socialize" those costs, applicants could be required to show that the benefits are broadly dispersed, and that they have selected the lowest-cost resource, including demand-side resources, reasonably available to meet the need in question.

Resource adequacy and system reliability across electric networks are classic public goods, provided to all interconnected users on essentially the same basis, and not easily withheld from any interconnected user. Efficiently constructed wholesale electricity markets, including adequate demand-side bidding systems, can moderate both the volatility of markets and the degree to which reliability managers must intervene in the market to ensure reliable service. Nevertheless, reliability and power market managers often find it necessary to take administrative actions to promote reliability. And typically, they seek to recover the costs of these administrative actions in broad-based rates charged to all users of the grid. These administrative actions take many forms:

- Requiring the provision of specified ancillary services by market participants by rule; and/or purchasing them on behalf of all market participants (and then imposing a tariff to pay for them);
- Socializing congestion costs, supported through uplift charges, so that customers in load pockets do not pay higher prices for power behind a constrained interface;[16]
- Entering the market directly through an RFP for the provision of reliability services, such as the emergency generators and dispatchable load contracts sought to be deployed in several power pools in recent summers;[17]
- Identifying needed transmission links and supporting their construction through broad-based transmission tariffs or other forms of "uplift" assigned to users throughout the pool;[18]
- There are many other variations on this theme.

[16] This has been the practice in New England for many years, involving quite substantial payments. Between May 1999 and January 2001, for example congestion costs recovered through uplift totaled over $184 million. "NEPOOL Market Uplift – What Is It?" Presentation by Scott Mallory, VELCO, May 7, 2001. No one has calculated how much demand response, distributed generation, or energy efficiency could have been delivered within New England's load pockets for that sum.

[17] There are many examples, involving both demand-side and supply-side resources. For example, in the summers of 1999 and 2000 the New England and California ISOs proposed collecting pool-wide uplift charges to bring in and operate emergency generators on barges anchored in the Connecticut River and San Francisco Bay. Several regions, including New York, PJM, and New England, have launched programs to acquire demand interruptions from customers who will agree to load controls operated directly from the ISO.

[18] In 2000, the New England ISO accepted a recommendation to support the construction of several transmission upgrades throughout the region, as "Pool Transmission Facilities" because they would relieve transmission congestion in certain areas, and improve the resilience of the transmission system. In NE-ISO parlance, the cost of these upgrades will be "socialized" -- that is spread among all users of the regional transmission system through a regional "uplift" charge. The New England 2001 Regional Transmission Expansion Plan calls for a number of transmission enhancements to support the reliability of the region's electric system.

System operators have traditionally focused on supply-side resources in meeting reliability requirements for electric networks, especially in periods of stress. However, for many system needs, there is a demand-side corollary that could perform that same service at lower cost, provided that market rules were defined to include such resources, and broad-based funding were made available to support them on the same basis as the more traditional solutions. Energy efficiency, load management, demand-side bidding, and distributed resources – in addition to traditional generation and transmission resources -- are all potentially cost-effective means of meeting reliability needs identified by system operators and power pool managers.

So long as vertically integrated utilities were basing their investment decisions on the principles of integrated resource planning, many reliability-enhancing decisions were governed by least-cost decision-making and associated regulatory review. With the breakup of the franchise, the demise of IRP, and the assumption of new responsibilities by RTOs and other regional organizations, there are now numerous occasions where broadly-funded interventions may be taken without serious consideration of less expensive and more reliable alternatives based on distributed resources and demand-side alternatives.

For this reason, reliability rules and investment decisions that will, by administrative action, impose costs on consumers and other market participants, could first be tested by the following standard for the efficient provision of reliability (See box below, "The Efficient Reliability Standard"):

The Efficient Reliability Standard

Before "socializing" the costs of a proposed reliability-enhancing investment through tariff, uplift, or other cost-sharing requirement, ISO-NE (and FERC) should require the applicant to demonstrate that:

(1) that the relevant market is fully open to demand-side as well as supply-side resources;
(2) that the proposed investment or standard is the lowest cost, reasonably-available means to correct a remaining market failure; and
(3) that benefits from the investment or standard will be widespread, and thus appropriate for support through broad-based funding.

If this standard were adopted as a screening tool when considering proposed reliability-enhancing rules and investments, it would provide a much-needed discipline in situations where expensive wires and turbines solutions are proposed to address reliability problems, and more robust, less expensive, distributed solutions are overlooked.

Opportunities to adopt and apply this principle arise in numerous circumstances. At the legislative level, Congress and state legislatures have seen many proposals to amend underlying enabling legislation relating to reliability. Statutory revisions in this arena could advance the principle that demand-side and supply-side reliability options should be treated equally in considering how best to address reliability needs.

FERC could also take the initiative on this point. Numerous state PUCs have long understood that least-cost principles should govern utility decisions to make investment decisions that they plan to recover from ratepayers. Increasingly, those decisions are being made today by RTOs, ISOs, Transcos and wholesale power pools, subject to FERC jurisdiction. FERC could require RTOs to ensure that decisions to socialize reliability improvements have been disciplined by a hard look at traditional, distributed, and demand-side alternatives.

Finally, it will be important that reliability and transmission planning processes be fluid enough so that RTO analyses under the Efficient Reliability Standard are updated and revised over time. Transmission planning often takes a long time, while market-driven, economically attractive alternatives may have shorter lead times, and may appear after a "build" decision is reached on the transmission alternative. To support both competitive markets and reliability objectives, the RTO transmission planning process should allow for changes in conditions that may reveal different reliability solutions (whether demand-side resources, distributed generation, or something else). In such cases, FERC's standards for cost recovery should encourage the "later look" and allow for cost recovery of planning and development costs when a project is prudently curtailed in favor of a less costly alternative.

(3) <u>Regional Reliability Charges</u>: NEDRI participants should examine the merits of region-wide investments in demand-side resources that would improve reliability and lower power costs. When supported by cost-effectiveness analysis, ISO-NE could be permitted to recover those investments on the same basis as regional transmission investments, ancillary service costs, or other RTO expenses.

Historically, utility energy efficiency programs were administered at the franchise level. More recently, many states have recognized the value of statewide programs and funding sources. But there is no essential reason to draw the boundaries for efficiency programs at the state line. Power markets today are regional; transmission grids and system operations are regional; and reliability rules and the costs of reliability programs are imposed across franchise and state boundaries. Moreover, the markets and delivery channels for many end-use technologies (such as industrial motors, chillers, and household appliances) are regional in nature. Finally, the economic, environmental, and reliability *benefits* of improved electric efficiency flow to consumers across power pools and transmission grids, and do not stop at the state boundary. For all of these reasons, policy-makers and other stakeholders should consider the merits of broad-based, regional funding for efficiency programs that will benefit regional power markets, regional reliability, and regional transmission systems.

The benefits of regional energy efficiency programs have been recognized by energy professionals and decision-makers in a variety of contexts. The leading example has been the Northwest Power Planning Council, which has sponsored very significant programs throughout the multi-state region served by the Bonneville Power Administration. In recent years, multi-state programs in the BPA region have also been developed and funded through the Northwest Energy Efficiency Alliance, a non-profit corporation governed by a board of utility, government, and other stakeholder representatives. As of 1999 it had an annual budget of $22 million per year.[19] Regional efficiency organizations have also been established in the Northeast and the Midwest.[20]

While the current regional efficiency partnerships offer promise, they are both voluntary and relatively small. What is lacking is a consistent funding mechanism to support delivery of demand-side resources in regional wholesale markets. Some modest load-management resources are now supported at the ISO level (see, e.g., the load-response programs sponsored by the New England, New York, and California ISOs in the summers of 2000 and 2001), but longer-term energy efficiency investments have been left to individual utilities and to state system benefit funds.

This is a missed opportunity for two reasons. First, regional power managers -- RTOs, ISOs, Transcos, and reliability organizations -- are engaged in the process of securing generation, ancillary services, reserves, and transmission projects on a regional basis. Where efficiency investments would meet those system needs at lower cost, the failure to invest in efficiency is driving up the *cost* of regional collection mechanisms, and of reliable power for the region. Second, efficiency investments can provide benefits to consumers across a region by lowering the *price* of power in regional power markets. Evidence from existing regional markets in California, PJM, and New England supports the conclusion that modest regional wires charges supporting regional efficiency programs could be highly cost-effective.[21] Yet, in the absence of a regional, non-bypassable collection mechanism, individual utilities and states will continue to benefit from their neighbors' programs, whether or not they support equivalent programs of their own.

Wholesale markets could be designed to capture large consumer savings through broad-based

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[19] Raab and Peters, "A Comparative Study of the Northwest Energy Efficiency Alliance and the Northeast Energy Efficiency Partnership," (NARUC 1998) at p.13.

[20] The Northeast Energy Efficiency Partnership sponsors about $20 million per year in efficiency programs in the region stretching from Maine to Maryland. It is funded principally by utility contributions, but receives some federal and state agency support as well. Ibid. The youngest of these organizations is the Midwest Energy Efficiency Alliance, also founded in recognition of the regional nature of electricity markets and efficiency benefits.

[21] These points are discussed in earlier NEDRI papers on price-responsive load, reliability, and energy efficiency.

market transformation or energy efficiency programs without much difficulty. With so much money to be saved and so many reliability benefits to be achieved, these questions should probably be high priority issues for FERC, state regulators, and other NEDRI stakeholders.

(4) Resolving the asymmetric risks of non-transmission alternatives -- One of the major flaws in attempts to expose transmission proposals to "all-source" bids is the asymmetry in risks to investors. Transmission investors know that if a line is built in rate base or under an RTO tariff, their costs can be recovered in non-bypassable, tariffed rates. Providers of non-transmission alternatives have no such option, and thus must assume a much higher set of market and investment risks. Research and policy development is needed to address this problem. An important option to consider is an "open season" bidding process to meet system needs, in which all winning bidders are given the same access to the tariff to return their costs.

(E) Conclusion : Topics for Discussion

In a world of competitive generation and emerging retail access, planning and managing the transmission grid – always a critical and complex task -- now pose new and difficult challenges. We are just beginning to understand the roles that distributed and demand-side resources can play in this new environment. NEDRI participants should consider the relationship between demand response and transmission, and the proposals sketched out above in developing a comprehensive view of demand side options for the New England region.