

Goodbye Gridlock 2:

How to End the Shortage in
Transmission Investment
that Led to the
Northeast Blackout



Goodbye Gridlock (2): How To End the Shortage In Trans- mission Investment that Led to the Northeast Blackout

An ESAI White Paper

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Goodbye Gridlock (2): How To End the Shortage In Transmission Investment that Led to the Northeast Blackout

Abstract

Despite the urgent need for new transmission infrastructure, investment has been extremely slow to materialize. The Northeast Blackout of August 14, 2003 puts transmission back on the front page. The problem will now be *where* and *how* to invest intelligently in transmission.

The following pages propose that the Blackout will empower Regional Transmission Organizations to intensify their development of transmission reliability projects that make such events even more uncommon. RTOs will also find, however, that tackling *economic* transmission projects will consume vast amounts of resources and political risk.

New independent *economic* transmission development – which is required if the grid is to be thoroughly modernized -- will occur only if some of the regulatory and financial risks now in place are mitigated. We suggest some reforms in this paper, including the adoption of locational capacity requirements in most control areas and “locational capacity reduction payment rights” to provide transmission projects with a form of baseload revenues.

We may need some tax incentives in the short run to make skittish capital commit to independent transmission development. If so, it should be designed as a “pump-priming” activity and retired as soon as possible, because the essence of power market reform in the last ten years has been to empower this industry to *transcend* its historic fully-regulated status. The Blackout is a reminder that electricity’s reliability requirements are critical and require an intelligent synthesis of regulation and respect for market forces.

Introduction

The Northeast Blackout of August 2003 has done the impossible: it has made electricity transmission a sexy topic. Much of the recent talk on cable news has concluded that the nation has ignored the power grid for too long, and that this neglect was the culprit in the blackout. The federal government, the pundits seem to agree, has to pass an energy bill that prevents this from ever happening again.

The Blackout has also polarized political positions on electricity reform that were already pretty stark. At one pole are the re-regulators, who see the Blackout as related to the decade-old federal effort at electricity market reform. They were pointing to Enron

and California as proof that electric markets don't work; now they add the Blackout to their list. At the other pole are the die-hard deregulators, who see the slow and haphazard pace of electricity restructuring at the heart of the problems that led to the blackout.

Most expert opinion is, as usual, between these extremes. It sees the Blackout as largely technical in nature, precisely the sort of "one in ten year" event to which the complex electrical system is engineered. Blackouts are not the result of deregulation: they also occurred when markets were comprehensively regulated. The system could be engineered to break down "one in twenty years" but that would cost lots of money: the cost curve to get from 99 to 99.9 percent efficient is asymptotic, but we have certainly learned (again) that the cost of that one-day interruption is huge.

Even before the massive blackout that rolled over northeastern North America on August 14, 2003, it was widely agreed that hundreds of billions of dollars needed to be invested in the transmission sector.¹ The Federal Energy Regulatory Commission (FERC) made it abundantly clear in word and in deed that it wanted to encourage private capital to make this investment voluntarily, instead of relying on mandatory payments from the captive ratepayers of the utilities. FERC's hope for private investment was an historic change in policy. For a century, transmission wires were strung on poles, buried into trenches and laid under water as a public service. Starting with its federal restructuring orders of the mid 1990s, FERC proposed that many of the major new transmission links within and between the three major electric transmission systems that emerged from a century of regulation – the eastern intertie, the western intertie and the Texas grid – be developed as unregulated investments. No longer would a utility have a monopoly over where and when to build transmission lines.

FERC's goals have not been accomplished. Transmission development, whether by existing utilities, or by the kinds of specialized independent and merchant development that overhauled the generation sector by adding thousands of megawatts of new ca-

¹ From the U.S. Department of Energy's *National Transmission Grid Study*: "There is growing evidence that the U.S. transmission system is in urgent need of modernization. The system has become congested because growth in electricity demand and investment in new generation facilities have not been matched by investment in new transmission facilities. Transmission problems have been compounded by the incomplete transition to fair and efficient competitive wholesale electricity markets. Because the existing transmission system was not designed to meet present demand, daily transmission constraints or "bottlenecks" increase electricity costs to consumers and increase the risk of blackouts."

capacity since 1995, has not been forthcoming. Instead, investors and developers concentrated on generation investment, and in the process created surpluses in many areas that only highlighted the need for transmission investment. That generation surplus was so significant that by the time the blackout occurred most of the most aggressive investors in electricity – not just pseudo-investors like Enron but also those who put real dollars at risk – found themselves shunned by Wall Street, the rating agencies, and investors.

The question, therefore, is *how* to modernize the system given the current state of federal and regional transmission policy and investors' aversion to all things electric. The FERC program to restructure the electricity business (a work in progress since the early days of the Clinton Administration) has had bipartisan support – and bipartisan opposition. The debate is now being framed as a question of whether the Blackout pushes us towards more directed investment in transmission, or towards market-oriented investment.

The answer has to be a hybrid of the two.

The Blackout

The Northeast Blackout of 2003 will change everything. Initial responses to the blackout have centered on the need to “update the antiquated grid”, to develop a “21st century transmission system” for the high tech North American economy. The Congress has been urged to “take on” transmission in the long-debated comprehensive energy bill. To the extent it does so, and truly does mobilize transmission investment, the Blackout will have profound effects. What follows the blackout could be changes in transmission that would be a powerful new step in the evolution of a competitive U.S. power market. In the process, the electric system will be fundamentally overhauled. The current corporate landscape of electric utilities – already much changed since the mid-1990s – will change even more as companies finally develop transmission strategies.

In spite of the horrible mess in the power market of California, the last ten years of development of power markets in Pennsylvania, New Jersey, Maryland, Delaware and Washington, D.C. (the PJM market), New England, and New York has been relatively successful. The Blackout was by no means a consequence of the development of these markets. To the contrary, the regional markets that have developed are increasingly effec-

tive transmission operating and planning entities. Blackouts will be less likely – not more likely – when the power market principles and regional transmission planning practices currently employed in PJM and New England are also applied in the Midwest (where the events causing the Blackout originated).

The power market principles used in the Northeast are straightforward: the price of electricity is determined by supply and demand at each node of the grid. The price emerges from an ongoing bidding process by generators and consumers. The bidding is conducted under strict rules that have successfully maintained a competitive environment. The pattern of these prices – high here, low there – presents useful information directing placement of new generation and transmission facilities.

All in all, the new power market of the Northeast – while complex because there are so many nodes in the grid – is similar to that of many other industries. The principle of *detailed pricing* reflecting local conditions is the norm in the American economy, and a centerpiece for attracting efficient investment. The main difference in the power market is that an RTO is needed to run the inherently interconnected system and oversee its transactions.

So why has there been so little investment in transmission in this new regime?

The Chain of Risks

Transmission investments aimed at enhancing system reliability are being made in the Northeast. The RTOs have developed processes that identify needs, provide the market with some time to offer solutions, and if these are not forthcoming, direct that the investment be made by utilities. The problem is that these processes have only recently developed. RTOs were initially more focused on setting up the other parts of their markets, to the detriment of developing clear regimes on transmission investment.

Meanwhile, there were several billion dollars of independent transmission proposals that have slogged their way through a very dense regulatory thicket. These projects have borne extremely high development costs (\$10 to \$20 million per project), years of regulatory reviews, and some opposition from incumbent market participants. One such project has been completed, and others are in advanced stages of the permitting process and could be in place within a year or two.

There are, in other words, two kinds of transmission investments that are being made: projects primarily aimed at stabilizing the grid, whose costs will be spread across all the customers of an RTO's area; and projects aimed at taking power from areas where it is cheap to areas where it is dear, which will be financed by those who benefit from the increased flow of power.

It is the “economic” investments in transmission that will truly and comprehensively modernize the grid. A few billion well-placed dollars will solve the reliability problem; it will take tens of billions of dollars to thoroughly modernize and optimize the grid.

These projects have had to contend with the ups and downs of the energy markets over the past few years. As one crisis – from California to Enron to the natural gas bubble to the Blackout – have roiled this sector, investors are understandable leery of committing hundreds of millions to individual transmission projects. That is why pure merchant transmission development – while a possibility a few years ago – is no longer viable. It will take years for investor confidence to return to the power sector.

That does not mean, however, that transmission needs to be centrally planned. The new electricity markets contain the information needed to direct market participants to where economic transmission is needed. What is needed is a hybrid of regulated and unregulated returns to make the chain of risks in transmission investment palatable, to avoid both the excesses of the pure merchant approaches of the Enron era and the pure utility approaches of the regulated era.

There are plenty of good ideas to get started: the Blackout provides the reason to give a number of them a chance to modernize the grid.

Location, Location, Location

The lesson of the Blackout is not that the transmission system “needs to be replaced” or comprehensively repaired. The first step in wisdom about transmission is that it is all about *location*. In 90 percent of the landscape of the United States, it is challenging, but possible, to establish a mix of generation and transmission assets that constitute an efficient power infrastructure. In the other 10 percent, it is extremely difficult to do so, and over time these areas have evolved into “load pockets.” These are typically densely

populated areas where generation facilities were built decades ago, are difficult to refurbish (and thus highly polluting) and where transmission grids are similarly dated and compressed.

The majority of the people in this country live in that 10 percent of the landscape. Thus, the central interest in transmission *policy* should be – but seldom is – in the 10 percent of the landscape that contains the load pockets of the power markets. The load pockets include most of the major American cities, and so *to a significant degree transmission policy should focus on how to bring power to the people who live in urban areas.*

The second step in re-thinking the transmission *business* is to define what its product is. If we are going to invest in transmission, we have to do so knowing that not all transmission lines serve the same purpose. Few new lines accomplish the original mission: bringing power to people who don't have power. Virtually all transmission investment these days has two different but interrelated purposes: to increase reliability of the overall system, and to increase the flow of energy from one point to another. The cost of reliability investments is typically spread across all the customers in a utility or larger control area. The cost of investments that increase the flow of energy from one point to another should be borne, according to both common sense and federal energy policy, by the beneficiary. These are the so-called “economic transmission investments.”

Most transmission projects have both reliability and economic implications, and one of the reasons for transmission investment gridlock in the past twenty years is that the rules for how to pay for economic transmission projects have been under development. We will show in this report how FERC's efforts to change the transmission investment paradigm have been unsuccessful thus far, and how they could be made more successful by making some additional changes to the new (and in some places controversial) power market rules called its “location-based marginal pricing” (LMP).

We believe lots of – perhaps too many! -- reliability investments will be made in response to the Northeast Blackout of 2003. But breaking the investment gridlock in economic transmission investments requires a deeper understanding of the product of such investments. In a direct-current (DC) project, the product will be a “transmission scheduling right” that entitles the owner to sell energy, capacity services, and other (“ancillary”) services from the source market to the sink market. Since DC lines are typically able to

carry power both ways, these services can be sold both ways: The sink can become the source.

The product on conventional AC lines is more subtle. Since these lines exist within a network of power lines and are typically not controllable as separate delivery entities, the effect of a new AC line is to increase indirectly the transfer capacity between source and sink. As a result, in markets such as the Pennsylvania-New Jersey-Maryland (PJM) Interconnection where “locational pricing” exists, the product of a new AC line so far has been measured as the difference in prices between the source and sink markets multiplied by the capacity of the new line. But beyond that truism, the industry and its regulators have been stymied by the following conundrum: Building a new transmission line erodes the very spread that the line was intended to capture.

In early 2003, however, FERC’s approval of changes to the PJM Tariff and proposals to change the New York ISO Tariff are useful modifications to its Standard Market Design (SMD) that – with additional tweaking -- could stimulate transmission investment. These are described in more detail later in this Report and can be summarized here as capitalizing on the establishment of specific capacity requirements for load pockets (the so-called “locational capacity requirements”) and the effective re-regulation of capacity markets (the so-called “capacity demand curves”).

With such modifications to the SMD, the future should see a variety of transmission investment models, both DC and AC, materialize in those parts of the United States and Canada governed by the SMD.²

² While we use the term “SMD” throughout this report, we understand and agree with the emphasis FERC placed in its [date] White Paper that opposition to SMD in many states required significant regional variation in market design. Hence, it replaced its “SMD” acronym with “Wholesale Market Platform.” We have seen little reference to “WMP”, however, and continue to believe that “SMD” is a more useful concept and will continue to employ it here, acknowledging that there will and should be significant regional variations to the design.

Transmission Has Been Neglected ...

U.S. High-Voltage Transmission System	
Voltage	Miles of Transmission Line
AC	
230 kV	76,762
345 kV	49,250
500 kV	26,038
765 kV	2,453
Total AC	154,503
DC	
250-300 kV	930
400 kV	852
450 kV	192
500 kV	1,333
Total DC	3,307
Total AC & DC	157,810

The U.S. electricity transmission system consists of over 150,000 miles of high-voltage transmission lines.

Source: NERC.

Source: U.S. Department of Energy, *National Transmission Grid Study*, 2002, p. 3

Utilities became accustomed to using captive ratepayer funds to build their local transmission networks and to make incremental and continuous local system improvements. As shown in the table nearby, a few utilities ventured long distances to get their power, creating some 300,000 miles of high-voltage transmission assets. Some of those were part of federal efforts to electrify rural areas or exploit what were once deemed to be “natural” sources of cheap energy, such as the Columbia River or hydro projects in Canada. More typically, however, transmission

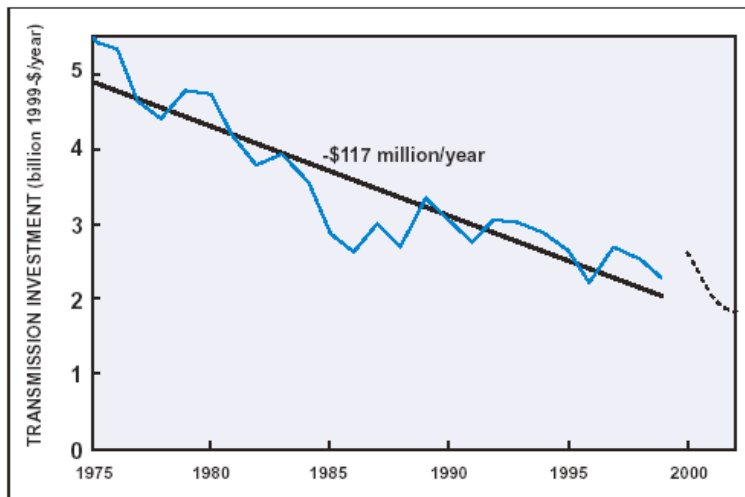
systems emerged over the decades, town by town and city by city, in small, tight, web-like and mostly self-sufficient clusters.

In some large cities, such as New York, the transmission infrastructure needed to light and cool and heat and power millions of homes and business became entangled with other infrastructure, evolving into elaborate subterranean honeycombs. Major additions or changes to such systems are as difficult as building superhighways through cities, projects that easily run into the hundreds of millions of dollars.

Overlaying the utility efforts to augment gradually what is now a century-old electric transmission infrastructure is a series of regional electric reliability councils, consisting of transmission specialists whose overarching mission is not efficiency but reliability. These North American Electricity Reliability Councils are not only advisory bodies; their verdict on whether a new line enhances or degrades electric reliability can make or break a new project.

Thus in the past, transmission investments have not been subject to the discipline of competition. Over the years, this has led to the emergence of variable regional transmission endowments ranging from some oversupplied rural areas to woefully underserved load pockets.

The traditional, regulated, utility-oriented system failed to develop the transmission network on a sufficient scale to reach 21st-century economic efficiencies. Put another way, it has been said that we have a 19th-century grid trying to power a 21st-century economy.



Investment in new transmission facilities has declined steadily for the last 25 years.

Source: E. Hirst and B. Kirby, 2001. *Transmission Planning for a Restructured U.S. Electricity Industry*. Edison Electric Institute.

Source: U.S. Department of Energy, *National Transmission Grid Study*, 2002, p. 7.

For the past decade, FERC has been engaged in a quest to modernize this most hide-bound of industries. It has encouraged state regulators and regional power market organizations to develop rules facilitating the activity that is the (usually misunderstood) centerpiece of any market:

trading. Thanks to Enron, trading is an activity that has fallen into disrepute, but it remains essential in a free society like the United States.

The basic idea behind trading could not be simpler: In its primitive form (to paraphrase R.H. Coase), it is the exchange of nuts for fruits at the edge of the forest; or, in its electricity form, the sale of power across distance. Over time, as the sources of electric power found their natural habitats, electricity trading has taken on the meaning of the sale of power over longer distances, rather than the traditional delineation of utility service boundaries. FERC's goal is to make these traditional service boundary delineations a thing of the past. If peaches grown in Georgia can be consumed in New York; then so can power generated in New Jersey.

... And the Recent Problems in Power Markets Do Little to Stimulate Interest in Transmission

Along the way towards this simple goal, the development of power markets hit two enormous road bumps. First, power trading got wrapped around the axel of overly aggressive financial institutions that took the basic principle of leverage and applied it – ultimately unsuccessfully – to the electric industry. The result was the rise and fall of Enron and Enron wannabes, a process that has generated so much fog that it is difficult for investors to see the way.

The second road bump was the development of power-market rules in California that simply did not work. The unfortuitous combination of aggressive traders and bad rules resulted in turmoil that virtually bankrupted several of the largest utilities in the state and generated enough legal work to enrich lawyers and expert witnesses for a decade to come. At the same time, however, and much less noticed by the press and the policy community, was the successful development of power markets in other areas, notably by the people at the PJM Interconnection. Initially, PJM rules were developed for the power grid serving Pennsylvania, New Jersey, Maryland, Delaware and Washington, D.C. Over time, however, its success has attracted other market areas, and PJM is growing to the west and is in the process of engineering a common market that proposes to stretch from Delaware to South Dakota, from Manitoba to parts of Louisiana³.

PJM's market principles are straightforward: The price of electricity will be determined by supply and demand at each node of the grid. The price emerges from an ongoing bidding process by generators and consumers. The bidding is conducted under strict rules that have successfully maintained a competitive environment. Market-clearing prices for each of the thousands of nodes have emerged since the system was imposed in the late 1990s. The pattern of these prices – high here, low there – presents useful information directing investors' placement of new generation and transmission facilities.

All in all, PJM's system – while complex because there are so many nodes in the grid – is similar to that of many other industries. In the oil business, for example, there

³ For an assessment of the benefits of this expansion, see Energy Security Analysis, Inc., *Impact of the Creation of a Single MISO-PJM-SPP Power Market*, available at http://www.miso-pjm-spp.com/information/general_documents/study_final_july29.pdf

are thousands of pricing points across the country where gasoline prices vary according to local conditions (differences in the cost of leasing a service station site, local taxes and so forth) and competitive circumstances. This principle of detailed pricing reflecting local conditions is the norm in the American economy, and a centerpiece for attracting competitive (i.e., non-subsidized) investment from the private sector.

FERC's Standard Market Design

On July 31, 2002, FERC capitalized on PJM's success by proposing to order that PJM's paradigm be applied to the U.S. market as a whole. This proposal has received a decidedly mixed reaction. Within the small community of power market advocates, FERC's proposal is seen as the only way to go. But in the broader community of stakeholders, traditional utility executives, state regulators, and federal politicians, there are many who oppose FERC's plan.

Their opposition is based on an array of arguments that boils down to the following: *Market forces do not work in electricity*. The upshot of this argument is that electricity should remain (along with agriculture and a few other select industries) outside of the mainstream of competitive enterprises in the U.S. economy.

FERC is seeking to impose its vision as quickly as possible, recognizing that prolonged uncertainty about the rules of the game will only defer the investment in transmission it hopes to encourage. As the period of time lengthens between the initial orders mandating the establishment of RTOs and the imposition of the standard market design, the likelihood grows that the U.S. electric market will be balkanized into PJM-style "markets that work" and a loose confederacy of more regulated markets. With each passing month, it is increasingly clear that FERC's vision of a few RTOs (three or four nationally) will not materialize. Even in the Northeast, where PJM, New York, and New England should have merged into a single market, it is now clear that they will remain separate entities.

Increasingly, it is clear that PJM is expanding south and west and will constitute the dominant power market where membership includes market-oriented utilities (and regulatory areas) with relatively low-cost (coal and nuclear) baseload units, a relatively (compared to urban and suburban Boston and New York) easier permitting climate and

for all those reasons a vibrant and efficient power market. New York, New England, and California constitute a looser confederacy of isolated, highly politicized and perhaps ultimately higher-cost power markets. Most of the South and the Midwest constitutes a different grouping, with marked aversion to the very idea of “SMD” and a determination to forestall FERC’s program.

In our own assessment of the situation, we are on FERC’s side: Electric markets can work, and PJM is a good “starting model” of how to structure an effective power market. But it is an incomplete model, and much will depend on how PJM’s current deficiencies are resolved in the years ahead.

The major deficiencies in the PJM model are its approaches to the “capacity issue,” which in turn has limited interest in transmission investment. This is the result of the fact that PJM itself is a relatively tight-knit grid. New York, New England and most of the rest of the country is not as well knit together from an electricity standpoint.

Tries to Lay Out A Uniform Capacity and Transmission Policy

The “capacity issue” is unique to electricity: How should we design a set of market rules that encourage people to maintain more electric generation facilities than are needed? We will return to this issue later, because it affects everything in the power markets including the primary topic of this report, which is transmission investment.

The transmission investment issue is also unique to electricity. Any review of transmission as a business has to begin by noting that the incumbents in the transmission industry will spend a lot of time and effort in the next few years on the transfer of existing assets to new, for-profit independent transmission companies (ITCs). Some transactions have already occurred, and more are underway. The *new* transmission capacity coming out of this transfer so far, as best we can tell, is close to zero.

Our focus here will be on transmission investments that *add* to transmission capacity. Specifically, we will evaluate transmission expansion projects in two contexts: those designed primarily to enhance the reliability of the system and those that take advantage of economic opportunities arising from a mismatch between where power is and where it is needed. The “reliability” of the grid is a public good. We have not figured out how to practically implement a “for-profit” reliability standard that would motivate en-

trepreneurs to make transmission investments. Therefore, reliability-related investments will continue to be financed largely by the network as a whole as part of the generic “network access charge” to the grid.

Economic transmission projects are a different animal altogether. Here, FERC would like to encourage entrepreneurs to build transmission projects that are paid for by “those who benefit.”⁴ As we shall show later in these pages, the purest form of economic transmission projects are dedicated direct-current (DC) lines between two different market systems. Examples of such projects are the recently completed Cross Sound Cable between Connecticut and Long Island and the proposed Neptune Phase 1 system between New Jersey and New York City and Long Island. Because DC lines are controllable and separable from the AC system, they lend themselves well to the requirements of project finance: an identifiable product (i.e., Neptune’s “transmission scheduling right,” or TSR), and a discrete price (the \$/MWh price of a TSR either in the original TSR contract between Neptune and the buyer or the price obtained in the secondary market).

We believe these “separable” DC transmission projects can be financed by the forward sale of TSRs. A load-serving entity could buy TSRs to move its energy and capacity purchasing points from its “home” area to a more distant and economically attractive (i.e., cheaper) area. A generator could buy TSRs to have a reliable, point-to-point pathway to a market it would otherwise not have access to. In either case, if the TSR buyer is a credit-worthy entity (a moveable designation these days), the long-term commitment to buy TSRs would form the basis of its financing in the classic merchant finance mode.

We will discuss the specifics of merchant transmission project finance later. All we want to do here is to introduce FERC’s reasoning on who pays for transmission expansion. FERC’s notice of proposed rule-making (NOPR) states that it “believes that a more precise matching of beneficiaries and cost recovery responsibility would encourage greater regional cooperation to get needed facilities sited and built. Our preference is to allow recovery of the costs of expansion through participant funding, i.e., those who

⁴ “Our preference is to allow recovery of the costs of expansion through participant funding, i.e., those who benefit from a particular project (such as a generator building to export power or load building to reduce congestion) pay for it.” FERC SMD at para 197.

benefit from a particular project (such as a generator building to export power or load building to reduce congestion) pay for it...”⁵

FERC then goes on to say investment in transmission is urgently needed but that it recognizes that many areas will not have SMD in place for years. As a result, it proposes an interim policy that distinguishes between areas with and without a functional ISO. Where there is not a functional ISO/RTO/ITP⁶, there is also not a truly independent entity developing region-wide transmission planning. Nevertheless, since FERC wants to encourage investments, it proposes a “default policy” in which FERC would allow a “roll-in on a region-wide basis [of] all high voltage network upgrades of 138 kV and above.”

This begs several questions that we must discuss next. If there are to be both “rolled-in” and merchant transmission projects, with the rolled-in ones financed by rate-payers and the merchant ones financed by what FERC calls “beneficiaries”, who decides what project ideas can go forward?

Transmission Plans to be Made By ITPs ...

FERC places great reliance on ITPs (i.e., ISOs and RTOs) to plan the future of transmission expansions in their market areas.⁷ The central planning role of the ITPs, along with the central investment role of the LSEs, are themes that will recur in the pages that follow. Following practices already in place in PJM, the New York ISO and the New England ISO, FERC would require the ITPs to “forecast the future demand for its area, facilitate determination of an adequate level of future regional resources by a Regional State Advisory Committee and assign each load-serving entity in its area a share of the needed future resources based on the ratio of its load to the regional load.”⁸ This process would lead to a regional “resource plan” in which the LSEs carry the bulk of the obligation to ensure that the reserve requirements can be met.

⁵ FERC NOPR at paragraph 199.

⁶ Independent System Operator, Regional Transmission Operator, Independent Transmission Provider

⁷ FERC defines an ITP as “any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, that administers the day-ahead and real-time energy and ancillary services markets in connection with its provision of transmission services pursuant to the SMD Tariff and that is independent (i.e., has no financial interest, either directly or through an affiliate, in any market participant in the region in which it provides transmission services or in neighboring regions).”

⁸ NOPR at para 474

Where is the independent merchant generation or transmission developer in this planning cycle? Clearly, developers have to be savvy about the ITP's plans. They have to make their project location decisions on the basis of the existing assets in place, the new facilities that are under development and the facilities that are in the ITPs project queue but which are not yet under construction.

FERC's SMD endorses the PJM and NY-ISO three-tier model of project development: a feasibility assessment, a system impact assessment, and a facilities design assessment. By the time a proposed project has successfully steered through these assessments, the developers will have spent several million dollars, making project development in the SMD's world a place for serious people with serious money.

Perhaps the most serious issue about the ITP's role in transmission planning is what the objective of the planning process will be. Is the ITP's transmission objective just to maintain a *reliable grid*, or is the objective also to minimize regional pricing disparities? If the former, there will be lots of room for merchant transmission investment; if the latter, merchant transmission projects will not develop further because there is no way investors can compete with socialized transmission projects.⁹

... Which Also Have a Role as Backstop Transmission Developer ...

FERC wants the ITP to "provide a backstop process for ensuring that needed transmission construction is undertaken."¹⁰ There is not much more information in the NOPR on this issue, but it will obviously be important to transmission developers. Most merchant transmission projects will be aimed at profiting from the congestion that makes the price in one area higher than another. A merchant transmission developer will invest several hundreds of millions of dollars of capital – not to eliminate the price difference between regions but to make money on what he thinks is an enduring difference.

Assume the merchant transmission line connects source area A to load area B and that before the project the price in A was \$10/MWh and in B was \$20/MWh. Suppose it

⁹ It is a challenge to make the private financing paradigm work for transmission, where assets are often 50-year properties, while project finance in generation typically works in 15- to 20-year cycles. If a private developer has to amortize a 50-year asset in 20 years while a regulated investment can do so over 50 years, the transmission charge of the private line will inevitably be higher than that of the socialized line.

¹⁰ NOPR at para 112

costs \$5/MWh to build a merchant transmission line from A to B. It pays for a generator in area A to buy that transmission right for \$5, add that to its cost and sell power in area B for more than \$15/MWh. In this scenario, the increase in capacity between A and B may lower prices in A from \$20/MWh but presumably not below \$15/MWh.

In this case, the investment in transmission lowered the price difference between A and B from \$10 to \$5/MWh. Will the ITP see that \$5/MWh as unwanted congestion that it must take steps to remove? Is that what FERC means by “backstop?” If so, the very existence of that backstop will throw cold water on the merchant transmission sector.

The backstop role of any particular ITP will create important distinctions between intra-ITP investments – where the ITP would have exclusive planning and project approval jurisdiction – and inter-ITP investments. The backstop power will have its most telling and chilling effect on the intra-ITP transmission projects: Merchant developers are likely to be concerned that anything they build may ultimately be trumped by ITP-favored projects that may look like reliability enhancers but effectively destroy the economics of a private investment.¹¹

Inter-ITP transmission investments will be less vulnerable. If it makes economic sense to build a transmission line between PJM and New York City (and it does, as discussed later), a merchant developer is more likely to build it than either the PJM or the NY-ISO.

The August 2003 Blackout was an “inter-RTO” phenomenon, and will certainly focus attention on how to control flows across seams better. Transmission projects that can provide it should be rewarded for enhancing controllability across RTO seams, but there are presently no specific financial mechanisms to provide such rewards.

¹¹ PJM’s musings on this subject – visible in the presentations it posts on its website – are informative. In the presentation given to the Transmission Expansion Advisory Committee Meeting on Feb. 26, 2003, PJM notes that the RTEP “will be reviewed with the state commissions in order to develop consensus around the need for the transmission upgrades that will affect each state . . . Operational performance analyses are a sub-set of economic performance analyses, except that, in addition to economic congestion considerations, it is determined to be desirable to improve some aspect of system operation performance. . . .” There then follow numerous observations about when and how operational (as opposed to reliability) upgrades could be implemented.

... While FERC, the States and ITPs Design the Permitting Processes

Transmission projects are as popular as root canals. Most community activists bridle at the thought of new swaths being cut across their areas for the purpose of erecting ugly towers that carry high-voltage power lines that are perceived to carry a health hazard in the form of EMFs. New gas pipelines can rely on FERC's powers of eminent domain; FERC has no such powers in the electric transmission area and is unlikely to get it.

In populated areas, therefore, it is unlikely that any major new transmission corridors will be established. As a result, a merchant transmission developer can route new projects either on existing power (or other) rights of way (like railroad beds) or lay the cable under water. The existing DC merchant proposals are submarine projects.

Once the proposed pathway is established, a merchant transmission project has to overcome regulatory hurdles at the federal, state and local levels. At the federal level, the relevant regulatory agencies are likely to be FERC and the Securities and Exchange Commission.

FERC controls how a new transmission company is allowed sell its product to its customers. Its authority over an incipient project is absolute, even though there is a widespread impression that deregulation has freed up the power asset development business. Even so, FERC is clearly anxious to stimulate transmission investment and – after taking almost a year to approve the first merchant transmission project (the Cross Sound Cable) – approved Neptune's proposed project in only three months. Filing for FERC permission to develop a power project, naturally, is not something one can "try at home." It requires engaging a law firm with specialized FERC experience.

In addition, the transmission developer must also apply for regional and state-level permits without which the project cannot be initiated. Where there is an independent system operator, one of the absolutely critical filings is with the ISO. In the Mid-Atlantic (PJM), New York and New England areas, the ISOs have developed the previously mentioned three-stage process of studies that gradually reveal the interconnections implications and costs of the proposed project. This process was developed for merchant generation projects and is being applied to merchant transmission proposals as well.

The three stages are (1) the feasibility study, (2) the system impact study and (3) the facilities study. At the feasibility stage, very preliminary estimates of the cost of in-

terconnecting the new facility to the regional grid are developed. If the developer chooses to continue, it must pay for the system impact study, which provides more definitive estimates of interconnection costs. Typically, all new project proposals are assigned to a “class year” and, to the extent possible, costs of accommodating all the new projects into the grid are allocated to each of the participants. At this stage, when the costs are prohibitive, projects are withdrawn. In the facilities stage, the projects that have survived the gauntlet of the system impact studies are given final and definitive interconnection costs, which then must be rolled into the projects own cost structure.

In PJM, New York and New England, there is now considerable experience with the project development paradigm. The primary issue between the developers of new facilities and the managers of the existing system is who pays for transmission grid enhancements and expansions. At the risk of caricaturing a complex process, we can say that developers often complain about their project having to finance a transmission enhancement that should instead be built and financed by the transmission provider. The “TOs,” in turn, often complain that generators are trying to get “free rides” from the regulated electric ratepayers.

The extent of the challenge of successfully navigating state-level permitting programs depends on the state. In some states, siting a new power facility is considerably easier than in others. We must reserve a special place for states like New York, California, Texas and Florida, which are a distinct group because their electric markets are more or less coterminous with their state political boundaries. As such, state public utility commissions have great say over all matters electrical, and there is often a tug and pull between state and FERC jurisdictional issues.

The other states are typically part of regional ISOs or RTOs. In these cases, state electrical jurisdiction is centered on siting issues. The process of siting a new generator varies from difficult to impossible, invariably takes years instead of months and typically takes twice as long as developers initially planned. There is no reason to believe the process of siting new transmission projects will take any less time and lots of reasons to believe it will typically take longer. Electric assets, after all, have to contend with the siting issues in the space defined by their footprint. A generator’s footprint is a rectangular plot of some 20 to 100 acres. A transmission line’s footprint can be miles long even though it

is only yards wide. If the transmission line goes underwater, there will also be coastal zones management permitting issues, federal environmental issues and boating and safety issues, all of which require marine surveys and subsequent plans to minimize disturbance and mitigate impacts.

Under the best of circumstances, the development process described thus far takes years and costs millions of dollars. Because this process may well turn up fatal constraints, the dollars spent on this activity are best seen as venture capital. In the generator development world, three or four projects (perhaps more) are launched for every one that is ultimately completed. In the merchant transmission world, given the even higher cost of the initial development processes, that ratio has to be better: Transmission developers will need to “score” a high hit rate if they are to maintain access to development capital.

Financing the development phase of generation projects was much easier in the 1990s than it is today, for obvious reasons. Developers and their financiers backed many projects that turned out to be located in the wrong places. Merchant transmission projects will not be able to make such mistakes, not only because the mistakes of the generation sector have run through all of the “stupid money” but also because merchant transmission projects will be entirely about location. Only the projects with obvious and enduring arbitrage value will get financed.

At the same time that they are checking off these federal and state regulatory punch lists, transmission developers also need to consider the ultimate structure of the entity that owns the line, because the Securities and Exchange Commission has reserved a special category of rules and regulations under the Public Utility Company Holding Act for companies that own electric facilities in more than one state. In the power sector, PUCHA defines a “public-utility company” as one that owns or operates facilities used for the generation, transmission or distribution of electric energy for sale. It generally subjects PUCHA company financing transactions to SEC review and approval and imposes restrictions on the corporate structure of the holding company that are likely to interfere with its ability to enter into other business. This is not exactly the kind of designation that would encourage most companies – which sell their shareholders on the portfolio benefits of diversifications – to enter into the merchant transmission business. As a result, companies are likely to go through substantial efforts to set up corporate structures

that impose PUCHA restrictions very deliberately. In most quarters, to be “PUCAHD” is regarded with as much relish as having a kidney stone removed.

There is more to be said about the regulatory hurdles that merchant transmission projects will undergo, but this is sufficient to drive home the point that all in all, developing a merchant transmission project is one of the more difficult undertakings in the American economy. The economic prospects better be good.

Locational Capacity Requirements Are The Key to Merchant Transmission Development

Of all the issues confronting FERC in its efforts to reform the U.S. power market, perhaps none is as difficult as a policy on reserve margins and capacity markets. With the suspension of investment in new generation, one can see looming capacity issues, especially in urban areas that missed out on the generation boom. Transmission expansion could be a critical part of the solution to this problem.

To outsiders, it seems at first odd that the federal or state governments have to deal with whether or not there is enough electricity generation capacity. After all, there is no particular requirement for capacity in petroleum refining or even natural gas supply. Deregulation in these industries was essentially a matter of trust, based on the premise that market forces would sort out the amount of capacity that would be required. When the capacity has been inadequate, business has found ways either to expand capacity in the market area or bring in supplies from more distant areas.

As those in the power business know, however, two factors mitigate against such a *laissez-faire* approach in electricity. First, modern society relies on electricity for provision of basic services that cannot be replaced by other services, at least in the short run. A disruption in electricity services, therefore, has consequences far beyond the loss of revenues to the immediate power buyer and seller. Second, all electric assets in the three primary U.S. electric “interties” are essentially parts of a single, enormous machine. The integrity and reliability of that machine cannot be put into jeopardy. Part of these machines’ requirement is a reserve margin to ensure that periodic failures of its component parts (generators, groups of generators, and transmission facilities) do not bring the entire machine to a halt.

The reasons for requiring reserve margins are obvious. If the reasons for requiring reserve margins are obvious, how best to ensure that these margins are maintained is not. Early in the deregulation process, the notion that one could employ the “market” paradigm to this particular requirement was widely held. Nepool, PJM, and New York ISOs all experimented with capacity markets. Five years later, these markets are widely believed to be ineffective.

It is important to evaluate the capacity *market* experience carefully because this remains one of the most problematic aspects of FERC’s SMD proposal. Essentially, the SMD rules stipulate that load-serving entities will be responsible for ensuring that there is enough capacity to meet their projected peak loads plus the designated reserve margin. This makes the LSEs the locomotive of electric asset development. There will be stiff penalties imposed on LSEs that do not meet their obligations.

In today’s functioning ISOs, LSEs can meet this capacity requirement either by contracting for it in bilateral transactions or by purchasing the capacity in the ISO-administered capacity markets. These markets are typically organized to offer capacity in various time frames – multi-month, monthly, weekly or daily. These capacity markets were never designed to handle all of the capacity transactions. To the contrary, they were contemplated as classic “spot” marketplaces, complementing larger and longer-term bilateral transactions between principals.

Locational Capacity Requirements in Load Pockets ...

The capacity parts of FERC’s SMD proposal envision that the RTO/ISO/ITPs would continuously study their respective power markets, forecasting both load and new generation and transmission projects, identify areas where investment is needed in either generation or investment, encourage the placement of that investment and, if the investment is not forthcoming, identify a “backstop” process whereby the needed investment would be made anyway but presumably financed by the ITP using rate-payer (as opposed to investor) money.

This process will rely heavily on the planning acumen of the ITPs. This is likely to have both good and bad effects. On the good side, organizations like PJM – running as they do real-time power markets with tremendous computational complexity – develop

unrivaled perspectives on the strengths and weaknesses of their systems. They release enormous amounts of data on the state of the market, ranging from real-time prices in thousands of buses to (six months after the fact) bidding data from market participants.

In addition, the planning process of the ITPs will probably hew to well-established protocols, yielding information “cases” that the analytical community will evaluate in the various widely used power-flow models and the associated economic and financial assessments. In that process, ITPs are obliged to include in their cases all of the actively pursued generation and transmission projects.¹² It is up to the prospective investor to cull these projects to get a more accurate representation of the most likely future state of affairs.

This may be loosely compared to a Defense Department procurement program, in which DOD assesses the threat and then issues RFPs to which its contractors respond. It is not the freewheeling, wide-open investment climate of real markets, and it will have many of the well-documented drawbacks of centralized decision-making. Nevertheless, this is the direction the power market is going. The free marketers have had their chance at turning electricity into a truly free market, and they botched it.

FERC’s SMD document notes that ITPs in some areas may want to take special measures to deal with load pockets. Indeed, the essence of the regulatory challenge may be said to be in these areas of the market. As noted earlier, since FERC’s initial moves to deregulate the power market, there has been a boom in generation development but not in transmission development. Generators typically picked the sites for their plants with an eye towards siting convenience and access to input fuels. Thus, there are many new power plants in rural areas and very few new plants in urban areas. Generators may have believed that if they built the plant, someone else (the ITP, the LSE) would build transmission to take the power to market.

As a result of the disparity in generation endowment, there are load pockets of varying degrees of pocket depth all over the country. Some are severely isolated and require enormous investments in transmission to join the market areas. To illustrate, look at New York and PJM. Both pools require that every load-serving entity have adequate

¹² There are differences in interpretation from ITP to ITP as to what entails active pursuit. There are many idle projects in the queues.

electric capacity, either owned or under contract, to serve its load and to meet a reserve requirement. In both pools, the generator that sells capacity in the capacity or bilateral markets must bid its energy into the day-ahead market every day.

In New York more than in PJM, the existence of load pockets has been recognized as a special problem requiring some adjustments in market rules. In New York, the needs of the load pockets have been addressed, in part, by a requirement that a minimum percentage of the constrained area's load be met by local generation. For example, 80 percent of the New York City peak load is supposed to be served by generating capacity located within the City load pocket. In Long Island, there is a requirement that 93 percent of the Island's peak load be served by generating capacity located on the Island.

Transmission investments can reduce these local requirements. In the case of New York City, for example, a 1996 study by Stone and Webster notes that the "in-city capacity requirement is a function of transmission cable import capability into the City relative to in-City load." Since the existing AC cable transmission system can only satisfy 50 percent of New York City's load, the minimum in-city generation requirement has to be 50 percent. Stone and Webster's study then goes through a logical progression of events that affect the reliability of either the in-city generators or the AC cables into the City to arrive at the view that reliability concerns require that New York City have an 80 percent "locational generation capacity requirement".¹³

This same logic indicates that as transmission capacity into the constrained market is expanded, the locational generation capacity requirement can be relaxed. While New York City has not yet had a merchant transmission project completed, Long Island has, and the new 330-MW DC transmission line into from Connecticut to Long Island market will reduce the locational requirement in that market from 93 to 87 percent.¹⁴

... Which Lead to "Capacity Spreads"

The Long Island case illustrates the effects of singling out load pockets for special capacity treatment. To ensure that electricity service remains reliable, the regulators impose a locational generation requirement. Because the load pocket is a heavily populated

¹³ Stone & Webster Management Consultants, Inc., "In-City Capacity Requirements Study," submitted to Consolidated Edison in November 1996

¹⁴ See Long Island Power Authority, *LIPA Energy 2002-2011*, page 7-24.

and developed area, building a generator there is likely to cost much more than in the countryside. Thus, it is widely accepted that a New York City or a Long Island power plant is likely to cost well over \$1,000 per KW of capacity, while the same facility located outside the urban or suburban area – Westchester County is not necessarily a cheap place to build! – is likely to cost under \$500 per KW.

The urban load-serving entity, however, should evaluate its long-term support on three different cost comparisons. The first is the comparative cost of qualifying capacity (i.e., capacity that counts towards satisfying its locational capacity requirement).

The New York ISO has already adopted the regulation that allows the locational capacity obligation to be satisfied either by generation located in the city or by a controllable DC line connected to committed generation capacity outside the city (or even outside the NY control area). The urban/rural cost difference is essentially a “capacity spread.” From a project development standpoint, this difference of \$500 per KW in capital cost sets a target for an acceptable cost of a transmission line. In other words, the combined transmission and rural generation capacity cost should ideally be no greater than the in-city generation capital cost for the merchant transmission project to make economic and business sense. The urban load-serving entity with the obligation to procure capacity should be indifferent between these two alternatives, except to the degree that the rural-generator-via-cable alternative provides environmental benefits such as lower noise and cleaner air.

Responding to the completion of the very first DC merchant transmission project – the Cross Sound Cable between Long Island and Connecticut – the NY-ISO has held that the locational reserve capacity requirements in New York may be satisfied via the specialized capabilities of DC transmission lines.¹⁵ Load-serving entities can satisfy both their locational and their pool-level capacity requirement via capacity contracts with generators in other areas, within the same ISO or in different ISOs, as long as they are connected by the controllable DC line.

Thus, a New York LSE could obtain capacity commitments in PJM via a DC line to PJM. To qualify for New York ICAP payments, that generator would have to be certi-

¹⁵ See New York Independent System Operator, *FERC Electric Tariff*, 2.194a1, Unforced Capacity Deliverability Rights.

fied as a New York capacity resource, and it would have to bid into the New York ISO's day-ahead market.¹⁶ The generator would have to be certified as a NY capacity resource to ensure that capacity is not double-counted and is dispatchable by NYISO if required¹⁷.

What if an LSE in a load pocket fails to take the necessary steps to comply with capacity requirements? The SMD and existing RTO rules impose heavy fines on the LSEs. In New York, the deficiency charge for 2002-03 has been pegged by NYISO at \$17.20/MWh for Long Island.

Which Could Lead to “Locational Capacity Reduction Rights”

The second criterion the LSE should use to pick between in-city generation and out-of-city-transmission-plus-generation is the energy price. If the transmission line connects the city to another expensive market (arguably the case with the Cross Sound Cable, which connects Long Island to a constrained Southwest Connecticut market), that comparison may favor the in-city generator. Ideally, the DC transmission line would connect the city to a low-energy-cost area.

The third criterion the LSE should use is the effect of the competing projects on its locational capacity requirement (if any). In principle, an AC or a DC transmission

¹⁶ One of the key issues in using DC lines for these purposes is the kind of interconnection – firm or non-firm – that will be required to satisfy the pool requirements for capacity resources. In this area, different pools have different definitions or approaches to “firm capacity.” As FERC noted in its SMD description, power regions have a variety of approaches to this issue, and it is apparently willing to continue to allow these differences “as long as the minimum level is the arithmetic equivalent of a 12 percent reserve margin” that it is proposing as the standard in the SMD. FERC goes on to cite some examples: “many [regions] use capacity margin, which is the ratio of the reserves to the amount of resources expected to be available during the period, expressed as a percentage. A capacity margin of 10.7 percent is the same as a reserve margin of 12 percent. Some may measure adequacy with a loss-of-load probability, called LOLP, which is a statistical measure of the expected total time during a period that generation will be unable to meet load. The common U.S. standard is one day in 10 years, which means that the sum of the hours (or fractions of hours) during a 10-year period when generation is expected to be short is 24 hours. Reserve margin cannot be translated directly into LOLP without studying a particular system. For example, an area served by a few large generators is more vulnerable to a shortage caused by an outage of one or two large generators than a similar area served by many smaller generators. The area with a few large generators may need a larger reserve margin to achieve the same LOLP. A general rule-of-thumb for a large U.S. utility system is that an LOLP of one-day-in-10-years is achieved with a reserve margin of about 18 percent.” Federal Energy Regulatory Commission, *Notice of Proposed Rulemaking*, July 31, 2002, p. 266.

¹⁷ An entity with multiple generators could certify some combination of units as ICAP providers and the combination could change from month to month. For example, if it had five 200-MW generators totaling 1,000 MW of generation capacity, it could declare 60 percent of each generator as a NY capacity resource. Alternatively, it could select Gens 1, 2 & 3 one month and Gens 3,4 & 5 the next month.

connection should result in some reduction in the locational capacity requirement.¹⁸ To be sure, this must be subjected to the usual (in the case of New York) one-day-in-10-year criterion known as the “Loss of Load Expectation.” Technical circumstances in the load pocket and how the ISO interprets these requirements will determine the extent to which the new tie line reduces the locational requirement.

Once the number of megawatts of relief is established, however, the value of that relief is essentially the number of megawatts of locational capacity reductions times the difference in locational capacity cost over the life of the project. For transmission developers, however, there is presently no way to monetize this service. There is as yet no “locational capacity reduction payment” in any of the ISO regulations, or in the SMD. We will propose at the end of this report that precisely such a payment be implemented in markets that have locational capacity requirements.

For LSEs in load pockets, however, a transmission project can be evaluated in terms of these three economic factors:

- 1) *The capacity spread*: The combined cost of the transmission project plus the cost of a capacity commitment in the unconstrained area compared with the capacity cost of an in-city baseload power plant with transmission interconnections into the same bus that the merchant transmission project would reach.
- 2) *The energy spread*: The energy price in the source market of the merchant transmission line compared with the energy price in the constrained market.¹⁹ That spread will be influenced by a wide variety of factors, including differences in fuels costs (urban gas can cost up to \$0.50/MMBtu more than suburban gas) and bidding behavior. An in-city CCGT would also be vulnerable to disruptions in the urban (and therefore somewhat volatile) in-city gas market, while a DC cable could tap into a baseload market with a variety of fuel choices for generation.
- 3) *The Locational Capacity Reduction Effect*: Using the criterion of 1 MW of relief of the locational requirement for every 1 MW of transfer capacity installed, and assuming the spread between locational capacity and “generic” capacity is \$10/MWh, the effect of a 600MW transmission project would be to reduce the locational capacity requirement by \$50 million per year. Most projects would not qualify for such a one-for-one payment, but this illustration makes the point that the economic effects of providing such a service can be substantial.

¹⁸ At present, whether the next DC transmission line into the City or into Long Island will in fact lead to such a reduction is unclear. The New York ISO is not required to implement such a reduction, although it did so in the case of the Cross Sound Cable.

¹⁹ For example, a line connecting New York City to the Jersey Central area would arbitrage a day-ahead market energy spread that has averaged \$15/MWh since the inception of the day-ahead markets in 2000. Forward price quotations at the time this was written (April 2003) for calendar year 2004 indicate a \$20/MWh energy spread.

The size and extent of each of these transmission values will vary, of course, from place to place. But this example illustrates that transmission solutions to the load pocket capacity problem may be able to compete effectively with generation solutions. Generation solutions have until recently had well-financed sponsors in the form of the dozens of power-marketing organizations that emerged in the 1990s. That era is now over, and we are beginning to see the first glimmers of transmission developers in the Cross Sound Cable and Neptune projects. The capital markets, however, have been traumatized by their losses in generation and are extremely reluctant to venture into merchant transmission without some assurances that the beneficiaries of the transmission investment will be willing to offset some of the risk of the projects with long-term commitments to use the services of the new tie lines.

Who will step up to the plate to do that?

From Policy to Practice

As a practical matter, the physical electric market is divided into an Eastern intertie, a Western intertie, and a large chunk of Texas (called “ERCOT”). Each can be seen as a continuously running, massive machine to which tens of thousands of generators, buses and lines of transmission cables are connected. Any addition or subtraction from that machine is an event to be noted, regulated, and ultimately subjected to market forces.

As noted earlier, the guardians of the physical integrity of the system are the existing transmission owners, the existing ISOs, and the relevant regional reliability council. These entities also have day-to-day control over operations and control over the permitting process whereby the newcomers – merchant transmission entities – would impose themselves into this system.

From the standpoint of developing new electricity assets, the interconnection protocols and policies of the ISOs, their predecessors, and their successor RTOs are at the absolute center of events. It is the ISOs that determine whether the interconnecting project will have to pay a little or a lot to hook into the grid. If the ISO determines that the cost will be in the tens of millions of dollars, that finding and that cost may well make or break the finances of the new project.

A new merchant generation or transmission project must run an expensive and time-consuming gauntlet to obtain permission to interconnect. The traditional American business model – that anyone can open a business on the corner of Maple and Main – could not be more remote than it is in electricity. The cost of developing a new merchant generation or transmission project is in the millions of dollars.

The costs begin when the developer identifies a site (in the case of generation) or sites (in the case of transmission). In addition to securing access to the sites and launching the state and federal regulatory processes already described, the developer has to manage the three-phase process in the ISO. From a practical standpoint, the ISOs have to study the evolution of the grid as if all of the proposed projects still in the system impact study stage will be completed. When there were scores of new projects in the queues, this inevitably led to an unrealistic portrayal of the future of the particular grid being assessed. In reality, many of the projects were withdrawn once the system impact studies revealed the likely costs of interconnection.

Within the PJM and New York ISO frameworks, the magnitude of these costs was supposed to be revealed to each “class year” of projects, and the costs of expanding the transmission capabilities of the grid were to be allocated fairly among the competing projects. As those projects were in fact developed, the ISO could point to several types of transmission investments: those made by TOs on their own initiative, those made and financed by the RTO on behalf of the grid as a whole and those financed by merchant generators as part of their development projects.

In the course of time, these processes allowed ISOs like PJM and New York to claim that their framework facilitated the evolution of several hundreds of millions of dollars of transmission infrastructure investment. Almost none of that investment, however, was intended to facilitate the movement of electricity from one zone to another (for example, from Rhode Island to Connecticut or from New Jersey to Delaware). Instead, most of the investment was aimed at a smaller geographic problem: taking power from a new generator into the nearest major substation of the grid.

This process raises a number of challenges to would-be transmission developers. First of all, it presents a complicated picture for an investment analysis. That’s nothing new to seasoned developers, but the complexity was clearly too much for some of the

early generation participants, who placed plants with little regard for their transmission realities. The manner in which the ISOs release information – in the form of power “cases” in which all proposed plants are assumed to be included – also guarantees that the first and simplest technical image of a region’s power future will be inaccurate because it is so indiscriminating. The seasoned developer will extract the projects that – in his judgment – are not likely to survive the permitting and financing gauntlet. These are difficult judgments, which have to continuously adapt to remain useful.

Existing ISOs/RTOs and TOs can exercise various forms of influence – some subtle, some not so subtle, to make it more or less difficult for merchant transmission developers to survive this process. By definition, under the FERC open-access rules, ISOs and TOs cannot discriminate between their own interests – including development of their own merchant transmission projects – and those of others. But a TO’s ability to remain even-handed in the granting of favorable interconnection locations has already been questioned in a variety of cases. As proposed merchant transmission projects become more numerous, TOs will be challenged as never before to maintain the “Chinese walls” between their own merchant transmission development interests (if any) and those of competitors.

The TO’s lukewarm embrace of merchant transmission developers is evident in examples such as the ISO’s inability to grant merchant transmission developers any kind of status in their roster of stakeholders. Thus, even a developer who has spent millions of dollars on an interconnection can participate in ISO proceedings only as a non-voting “guest.”

PJM presents a somewhat different and perhaps unintended case of regulatory hurdles that affect competition in transmission investment. Organizations that are “transmission providers” can develop merchant transmission plans outside the view of PJM’s public web site. They can prepare feasibility studies and system impact studies on their own (as long as they comply with PJM’s technical standards). Their competitors will not see their plans as long as these studies are underway. Organizations that are not PJM “transmission providers” (such as independent transmission project developers) must contract with PJM to conduct these studies. The results are publicly posted soon after the

studies are completed. And so there is a visible trail of their intentions, while the trail of competing projects from “transmission providers” can remain hidden.

This disparity in the visibility of the study processes between a transmission developer and a recognized incumbent transmission provider can have adverse competitive effects on the former. There are few suitable sites for transmission development, and the ability of one party to bring a project to maturity stealthily while another must divulge all of its plans to its competitors is obviously not conducive to the emergence of a specialized merchant transmission development sector.

Merchant Transmission Developers Have Rights Too: SMDs’ Planning Protocols

Congestion Revenue Rights (CRRs²⁰) will be central to the economics of merchant AC transmission projects. Many DC projects will not entail significant upgrades to the AC system and thus will not incur significant CRRs. When a DC project does entail significant AC upgrades, however, CRRs will be an important albeit secondary source of revenues to the project.

A project developer only discovers the extent of upgrades for a proposed interconnection towards the end of the “system impact study” process that is administered by the RTO. One of the difficulties of all electric investments is that the developer’s first ideas about the desirability of an investment may or may not be borne out by the subsequent “definitive” studies by the RTO. Even then, there may be a significant re-allocation of costs among the participants in a “class year” of projects if some of the members of that particular yearly cohort of projects drop out of the class. There is, in other words, a kind of circularity (perhaps unavoidable) in this process as a series of studies is launched assuming all projects will remain in the class, the results of which then force some of the projects to be cancelled, requiring a reallocation of costs among the surviving projects, which in turn may force more of them to drop out, and so forth.

The CRRs associated with a particular merchant transmission project will therefore remain an uncertain revenue item for some time during the project’s initial life. If

²⁰ Also known in PJM as a financial transmission right (FTR) and in New York as a transmission congestion right (TCC).

one assumes a project idea is born in month 1, by the time the SRIS results are available, the project may be in month 12. Presumably, to keep the development process going, the developer will have filed with the states for their permits, perhaps made options payment on sites, worked on the always-difficult issue of transmission line siting and so forth. In other words, the developer is likely to have to spend \$5-10 million in project costs before obtaining detailed information on the project's interconnection costs and its CRR entitlements, if any.

Once the studies are finished, the RTO will issue CRR entitlements, if any, to the merchant transmission project. Congestion revenue rights, like PJM's Fixed Transmission Rights, involve payments defined by charges "attributable to the increased cost of energy [in the day-ahead market] delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions."

FERC's NOPR stipulates: "The Independent Transmission Provider shall award to all Market Participants that fund additions to the transmission system Congestion Revenue Rights to equal the capability created by the expansion."²¹ Later in the NOPR, FERC observes: "Most likely, the beneficiary(ies) of the economic expansion of the network would pay for the cost of the new facilities in return for any Congestion Revenue Rights created by an increase in transfer capability, and will continue to pay the access charge to receive Network Access Service. Otherwise, all network expansions would be rolled in either regionally or to a license plate zone and, therefore, all newly created Congestion Revenue Rights would be auctioned."²²

These NOPR clauses indicate that the investor in "economic" (as opposed to reliability) expansions in transmission will receive CRRs, which he will then auction to the

²¹ NOPR at page 77. It further goes on to say that "the Congestion Revenue Rights awarded in combination with all other awarded Congestion Revenue Rights, must be Simultaneously Feasible as described in Section D.5.8 in light of the Total Transfer Capability available under normal operating conditions. Such Market Participants shall be allowed to choose any set of Receipt Point-to-Delivery Point Obligation Rights that meet the requirements for Simultaneously[sic] Feasibility. Such Market Participants shall also be allowed to choose any set of Receipt Point-to-Delivery Point Option Rights and Flowgate Rights that meet the requirements for Simultaneous Feasibility, as soon as it is it is feasible to issue such rights. Such Market Participants may elect to receive no Congestion Revenue Rights if, but only if, all outstanding Congestion Revenue Rights are Simultaneously Feasible in light of the Total Transfer Capability available after the additions under normal operating conditions. [The Independent Transmission Provider file a Commission-approved, nondiscriminatory methodology for allocating Congestion Revenue Rights among multiple Market Participants that fund any single transmission capability addition.]"

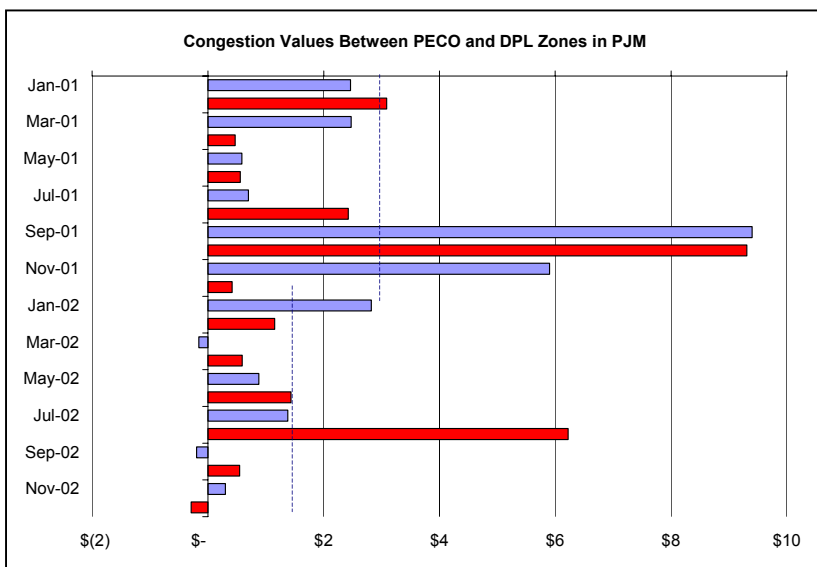
²² NOPR at page 8.

beneficiaries of the transmission expansion. For example, if a DC transmission project increases the transfer capacity from a variety of nodes into its source node from 600 MW to 1,200 MW, its developers will own the CRRs.

From a financing perspective, what are these CRRs worth?

Create CRRs That Have Value ...

The value of Congestion Revenue Rights is defined by the prices in the day-ahead market between the various zones in a given market. Over a long period of time, the value of any given pathway's CRR is a function of the growth in load, the generation capacity added or retired,



changes in the transmission network as a whole and in the vicinity of the path and the market behavior of participants, in each of the interconnected zones. Within a short period of time, the CRRs may be quite volatile; over a

longer period of time, they should reflect the fundamentals of electric supply, demand and transmission.

Yet the industry has been stymied by the conundrum that building a new transmission line erodes the very spread that the line was intended to capture. This concern can be summarized as follows. Assume a merchant transmission developer had an interest in expanding the transfer capacity between the PECO and the DPL zones of the PJM market. Congestion between these zones averaged \$3.15/MWh in 2001 and then declined to \$1.22/MWh in 2002. If augmenting AC transfer capacity between these zones by 300 MW eliminates the congestion, the CRRs would be worth nothing. So the developer would have to size the project quite precisely – and conservatively – to avoid destroying its own spread.

Thus, the CRR is affected by many moving parts that make both the quantity and the quality diffuse. All in all, this is not the kind of “product” that is likely to easily attract investor interest. In addition, as of 2003, there is still significant uncertainty about FERC’s ability to sell its Standard Market Design to the country beyond the east coast, the only place it exists and is deemed to be effective. To the best of our knowledge, no transmission or generation projects have yet been financed based on their CRR rights²³.

But looking just at PJM’s CRR auction market, there are indications that the auction process is working and that the volume of MWs is steadily increasing. In addition, our analysis of the prices paid for CRRs, compared with the subsequent actual price differences between the nodes and/or zones, indicates an overall rational process of valuation by the PJM market participants.

As a result, transmission project developers should have some confidence that the CRRs obtained from a significant investment in upgrading part of the transmission system have a market. The ISO rules allow CRRs to be sold in bilateral markets, and the only question for the merchant transmission developer is whether it can recover sufficient revenue over a sufficiently long period of time from this sale to meet its financing requirements. At present, CRRs may last for decades, but they are sold in relatively short (from a financing standpoint) increments of several years. It is not clear in FERC’s SMD proposal whether long-term bilateral sales of CRRs can be part of the kind of 20-year contract structure with credit-worthy parties that is required for developing transmission in a project-finance mode. The merchant transmission developer will need to have contractual flexibility to complete the chain of transactions needed between generators and load-serving entities within or between ISO/RTO/ITP areas.

Finally, we reiterate our view that CRRs will not be an adequate mechanism for financing significant AC transmission expansions. They understate the true value of transmission projects to load-serving entities, especially in those markets that have *de factor* or *de jure* locational capacity markets. For that reason, ESAI’s proposed “locational capacity reduction rights” (see separate chapter later in this report) constitute a better “base load” or “firm” revenue stream for financing the debt portion of merchant trans-

²³ In order to manage the profusion of acronyms, we will refer in this section only to CRRs, and not to PJM’s FTRs or New York’s TCCs.

transmission projects. CRRs would then be relegated to a more proper role of “variable” revenues stream more appropriate for the equity portion of the financing of a merchant transmission project.

... But CRR Values Are Not Financible

The CRR, in a nutshell, “entitle[s] the holder to receive specified congestion revenues in the day-ahead market. To the extent that a customer's real-time schedule coincides with its day-ahead schedule and its Congestion Revenue Rights, these rights offer complete protection against uncertain congestion charges.”²⁴ In this formulation, the day-ahead market and the hour-ahead market play crucial roles.

Anyone who would buy or sell power faces financial risk. In power, that risk can be confined to changes in the price within a given area. Thus, a generator located in PJM’s PenElec zone may choose, if it so desires, to sell power only within that zone. In that case, its power price risk can be largely defined as stemming from the dynamics of supply, demand, imports and exports within that zone.

Under PJM’s existing rules, and under the SMD, that same generator may also choose to sell its power to a load-serving entity or a trading company in another, more distant zone. By participating in an SMD market, the generator has the right to make such a sale, subject to the condition that it do so according to SMD protocols for such sales. In essence, that protocol is designed to maximize the value of the existing transmission lines by assigning the rights to capacity on those lines, and then establishing a market whereby those rights can be bought and sold. These CRRs are “financial contracts that entitle the holder to a stream of revenues (or charges) based on the [day-ahead market] hourly energy price differences across the path”.²⁵

Thus, any company that owns a CRR on a given path has a stake in the relative day-ahead market economics of the points on either side of the line. Assume that a generator in the PenElec zone in Pennsylvania contracts to sell energy to a load-serving entity in the PSEG zone in New Jersey via a one-year bilateral contract. Based on average 2001 price information, the PenElec price might be expected to be \$30.46/MW and the

²⁴ NOPR at para 136.

²⁵ From PJM, *PJM and LMP Refresher Course*, available on www.PJM.com

PSE&G price \$33.04/MW. Neither party, of course, can be certain that this same \$2.58/MW price difference will prevail during the contract term of their new transaction. The FTR between the two points is at the stipulated price for delivery to the PSE&G location.

The seller is responsible for shipment from injection point to withdrawal point and is responsible for the congestion costs, the delta between the LMPs. This is a financial contract, and thus the buyer or the seller in this transaction should be willing – if they believed the future prices would be exactly like the past – to pay up to \$2.58 for the FTR.

In the bilateral part of this transaction, the buyer will make a payment to the seller at the stipulated price. As this particular transaction is executed in the PJM-administered market, the seller will obtain whatever the LMP price is in PenElec, the buyer pays whatever the LMP price is in PSEG, and whichever owns the CRR/FTR will get the payment (or pay the charge) equivalent to the price difference between the sink and the source.

The possibility of such a transaction should make buyer and the seller aware of the world outside of each company's immediate utility zone. It brings attention to the transmission constraints that prevent them from dealing directly with one another. And over time, the price differences between the zones should motivate investors to either build generation or transmission to capitalize on the differences.

So much for how the CRR/FTR is supposed to work. Experience in PJM to date indicates that some traders understand it and are willing and able to utilize FTR auctions as part of their business programs. That cannot be said, however, for transmission developers. To date, there has not been a single transmission project developed on the basis of CRRs or FTRs. To understand why, we have to go into the world of merchant transmission project finance.

Investors' Perceptions Are the Eye of the Transmission Investment Needle

In FERC's vision of how the U.S. power market will work, transmission projects will be made either by the merchant sector – defined as the cohort of project developers and merchant affiliates of existing power companies that specialize in power – or by the

existing transmission organizations on the basis of the principle that “the beneficiary pays.”

In the past 10 years, investors have massively favored merchant generation over transmission assets. Much of this investment has been made under what might be called “Field of Dreams” assumptions: If we build generation, no matter where, customers will come.

We at ESAI have been involved in generation plant valuations since 1997. Early in this process, we consistently – and often to the disappointment of our clients – failed to come up with the “winning” valuation that would have secured the plant purchase for our clients. We developed our basic paradigm for electricity prices from the petroleum-refining sector, from which we learned that large processing spreads are ephemeral and that good companies build good plants in good locations and manage the hell out of them to be successful. As a result, “spreads” between finished petroleum products and the raw material are, in the long run, mean reverting.

In power, companies that applied that paradigm to the plants available for sale from 1995 to 2001 would not have bought any – which turns out, of course, to have been a good outcome. We recall a conversation with a shrewd investment banker who noted that there would be a period of 10 years of “dumb money” flowing into generation, inflating its value to the point where, at the end, there would be fire sales. That comment turned out to be on the money, except that it took only five years for the bubble to burst.

Several hundred billion dollars were invested in new generation facilities under the Field of Dreams assumptions. This is germane to the future of transmission investment for the following reason: *A decade of over-investment in generation has led to widespread asymmetries in the availability of power, especially between urban, suburban, and rural areas.* Most power generation developers did not concern themselves much about the location of their facilities. Sites were chosen more on the basis of project development criteria – cost of the site, proximity to fuels, water, and local tax regimes – than on the basis of the location of the plant in the grid or proximity to load centers. The result: lots of power outside and not enough inside the urban areas.

The consequences are now being visited on the generators. Electric prices in the overbuilt areas have done what they do in any industry: They have collapsed (at least in

terms of the margins earned over input fuels prices). Meanwhile, prices in the under-served areas have remained high and in some cases increased in relation to the prices in the overbuilt areas.

Many, if not most, of the new power facilities were built under very special financial and contractual provisions. Facilities in other energy industries – for example, coal mines, gas fields or petroleum refineries – are typically built with the capital of the developing company, with a minority role for banks and debt issuers. For that reason, energy has traditionally been regarded as among the most capital-intensive industries in an advanced economy.

In electricity, in contrast, a practice developed to finance power plants with a minimum of equity and a maximum of debt. The intensive use of debt typically required that projects be financed by the bank market during their development phase and then be “flipped” into the bond and permanent equity markets when completed.²⁶

The worst-case scenario for banks has now arisen: There is a wave of new power plant refinancing due in 2003 (estimates of up to \$80 billion) that the sponsors are in no position to complete. Banks will either have to roll over much of this debt or force their customers to put up the required equity to move the plants off the banks’ books. The trouble is, the customers do not have the equity and if pushed too far will slide into bankruptcy protection. We have called this process a slow-moving avalanche; it began even before Enron’s insolvency and has gathered steam ever since.

Some will argue that the situation is not so dire, that in the process of qualifying for non-recourse debt for specific projects or groups of projects, the debt issuers typically required that the output of the facilities be sold to credit-worthy entities via long-term power purchase agreements. Where that power was sold to existing and still credit-worthy load-serving entities (e.g., the Con Edisons of the industry), that commitment might well save the day. Where the power was sold to large trading companies (e.g., the Enrons and Williamses of the industry) the credit quality of that commitment has fallen, in some cases to untenable standards.

²⁶ For a useful description of these financing practices, see Benjamin Esty and Michael Kane, “Calpine Corporation: The Evolution from Project to Corporate Finance,” Harvard Business School, 9-201-098, January 22, 2002 (revised).

The “project finance” development and financing structure was extremely successful in terms of stimulating the development of more than 100,000 MW of new, mostly gas-fired power-generation capacity in the United States (and to a lesser extent abroad). These programs allowed investors to get enormous bang for their equity buck and provided what appeared to be attractive vehicles for the debt market as well.

All of the air, however, has been let out of this balloon and many of the sponsors of these structures are noodling over how to survive the next couple of years. They are, for all practical purposes, not in the energy project finance business anymore.

In evaluating the causes and consequence of this state of affairs, it is important not to throw the baby out with the bathwater. The prime mover of the bubble in generation was bad judgment. Many, if not most, of the new plants are good business assets. They were financed on assumptions that *for the moment* are considered untenable. As a result, the cash flows are not what the over-leveraged sponsor/owners need to meet their requirement. As these entities slide into oblivion in a classic Schumpeterian example of destructive competition, the plants will be sold at fractions of their cost, and those sales will better align the capital value with the market conditions. All in all, the U.S. economy will be significantly better off with these efficient new facilities.

Part of the realignment of the capital values of these new plants (and of old plants as well) is a greater awareness by the new owners that, in electricity much more than in other energy businesses, *location matters*. We have already done a number of due diligence studies on these sales where we adjusted our assessment of the plant value because of transmission constraints. Our clients submitted conservative bids that were initially rejected, only to have the sellers return later, reluctantly willing to lower their asking price to meet the new, and more reasonable, bids.

So the project finance paradigm is not dead; rather, it is being recalibrated. Instead of 80/20 debt equity ratios, we will see 60/40 or 50/50 ratios. Instead of ignoring transmission realities, the market is now transfixed by them, and with that will come investor awareness of and willingness to invest in merchant and neo-regulated transmission projects.

Can Merchant Transmission Be Project Financed?

That is not to say transmission investment will be easy. It will be extremely demanding. It will not have the cookie-cutter characteristics that facilitated merchant generation investment. It is doubtful the dumb money will flow into this sector as it did into generation. An important part of the difficulty will be that the transmission sector overall will remain a tale of two coexisting systems: the network services that will remain socialized to the extent that investment is needed to maintain reliability and the merchant services aimed at specific economic opportunities.

Thus far, the merchant transmission business is limited to a small group of developers, utility affiliates, and investors. Among them are utilities and investors that were not burned by the bursting of the generator bubble and indeed see opportunities in it.

The driving force of merchant transmission projects is *spreads*. In essence, merchant transmission projects will be investments in *durable energy and capacity market spreads*. For the purpose of investment, differences in power prices in a given natural market (for example, the northeastern United States) can be divided into durable and transitory spreads. Transitory spreads are spreads that can be closed by the relatively easy construction of a new generator in the high-priced area, or, under the rules FERC is imposing, relatively small, incremental upgrades to the existing AC transmission grid.

Durable spreads arise because (1) it is literally impossible or prohibitively expensive to build a power plant in the high priced area and (2) incremental upgrades to the existing grid cannot be made or are not adequate to the task. Where large, durable spreads exist, we can expect to see economic or merchant transmission projects.

First and Second Images of Merchant Transmission

FERC has issued several pivotal orders on merchant transmission, particularly DC projects.²⁷ The first of these broke the ice and got the industry and investors thinking about the issue. Subsequent orders laid down a more complete pattern of rules and regu-

²⁷ See Federal Energy Regulatory Commission, "Order Approving Proposal Subject to Conditions: Neptune Regional Transmission System," Docket Number ER01-2099-000. See also the Transenergie ruling, 91 FERC at 61,838.

lations governing how the services of merchant transmission lines would have to be made available, how the lines could be financed and the tariffs they could charge.

FERC and the traditional transmission sector's first image of merchant transmission borrowed extensively from how FERC treated gas pipelines 10 years earlier. The Commission asked merchant transmission entities to sell their services in "open seasons" – essentially blind auctions aimed at ensuring that all potential customers would have "equal access" to the new lines. It prohibited transmission entities from selling their services to affiliates, essentially precluding major energy trading companies from investing in projects that they might also want to use for trading purposes. It ordered that the transmission assets be run by the existing regional transmission organizations, rather than be managed as separate electrical trading platforms. And it indicated that merchant transmission owners had to put in place procedures that would assure that none of the capacity was withheld, even if the service had to be sold at a loss.

Not surprisingly, these rules have turned out to be too cumbersome to encourage new entrants. Three years after the initial Transenergie filing and two years after the initial Neptune order – both perceived by industry participants as positive steps in the evolution of merchant transmission – there are still few entities developing merchant transmission projects in the United States and Canada.

Among the flaws of the pipeline model is the requirement to conduct an open season for the sale of transmission capacity. Once the open season has been held and a winner chosen, the balance of power between buyer and seller shifts radically in favor of the buyer. Once chosen, it is in the interest of the buyer to game the inevitable negotiations to finalize a contract in order to drive a better and better deal from the developer for whom the time value of money is almost certain to be higher than for the user.

Another set of rules for merchant transmission is those established by the ISO (or RTO or ITP), where there is one. In the spring of 2002, PJM launched an initiative to revise its Open Access Tariff via a process of discussion of draft changes in the OATT with its stakeholders and merchant transmission providers. By the fall of 2002, these discussions had led to a short list of merchant transmission rights, as well as a process for studying merchant transmission project proposals.

FERC approved PJM's Tariff changes to accommodate merchant transmission in March 2003. That approval introduced a new set of acronyms into the electric lexicon. Specifically, PJM has identified the following rights (and obligations) for those who would invest in the transmission system it has the responsibility of operating. For transmission projects connecting PJM to another control area:

- Transmission Withdrawal Rights (TWRs). Firm TWRs would allow a generator in PJM to offer capacity services to the control area at the other end of the line, assuming that "PJM firm" would be compliant with the definition of firm in the sink area. Non-firm TWRs would allow a generator in PJM to sell energy (and perhaps some ancillary services) to the sink area.
- Transmission Injection Rights (TIRs) are the mirror image – rights to bring capacity and/or energy services into PJM from another control area.
- For AC transmission projects within PJM, the pivotal concept is Incremental Deliverability Rights (IDRs). Essentially, this is the measurement of the increase in the amount of generation that can be injected at a location as a result of an AC transmission project.

With these changes, FERC, PJM, and the merchant transmission developers are helping to define a second image of merchant transmission, one in which the developers and financiers have more flexibility to arrange for customers, to hedge their investments, to sell what Neptune calls "Transmission Scheduling Rights" with a variety of durations, to sell options to those rights if it so chooses and to engage in other creative forms of product development that were the reason for FERC's decision to transform the sector from a regulated to a competitive model in the first place.

The Capacity Demand Curve in New York

FERC's SMD plan notes that ITPs in some areas may want to take special measures to deal with load pockets. As noted earlier, New York, more than PJM, has recognized the existence of load pockets as a special problem requiring some adjustments in market rules. In New York, the needs of the load pockets have been addressed, in part, by a requirement that a minimum percentage of the constrained area's load be met by local generation. For example, 80 percent of the New York City peak load is supposed to be served by generating capacity located within the City load pocket. In Long Island, there is a requirement that 93 percent of the Island's peak load be served by generating capacity located on the Island.

Since these local requirements stem from the fact that load growth has outstripped transmission investment in the first place, it stands to reason that new transmission lines should reduce the local generation requirement. In the case of New York City, for example, a 1996 study by Stone and Webster noted that the “in-city capacity requirement is a function of transmission cable import capability into the City relative to in-City load.” Since the existing AC cable transmission system can only satisfy 50 percent of New York City’s load, the minimum in-city generation requirement has to be 50 percent. Stone and Webster’s study then goes through a logical progression of events that affect the reliability of either the in-city generators or the AC cables into the City to arrive at the view that reliability concerns require that New York City have an 80 percent “locational generation capacity requirement”.

Thus, as new transmission capacity is built into the constrained market, the locational generation capacity requirement can be relaxed. While New York City has not yet had a merchant transmission project completed, Long Island has, and the new 330-MW DC transmission line into from Connecticut to Long Island market will reduce the locational requirement in that market from 93 to 87 percent²⁸.

That reduction has real value for the load-serving entity. How much value depends on the size of the “spread” between the cost of capacity in the constrained zone and the cost of capacity in the unconstrained zone. If workable and competitive capacity markets existed, it would be easy to take this measure. But in New York as elsewhere, capacity markets are not functioning well. As a result, in New York, much thought has been given to effectively re-regulating the capacity market via a mechanism known as the “capacity demand curve.”

The Board of New York ISO agreed in March 2003 to implement (subject to FERC approval) a “capacity demand curve” policy that entails a payment schedule by LSEs to generation whose size depends on the overall adequacy of generation in relation to requirements. If implemented, it would prevent capacity payments from “falling off the cliff” during periods of surplus in exchange for preventing them from “going to the moon” in periods of deficit. In its filing to FERC, the NY-ISO acknowledges that a “ca-

²⁸ See Long Island Power Authority, *LIPA Energy 2002-2011*, page 7-24.

capacity spread” exists between the cost of generation in New York City (\$159/kW of Installed Capacity per Capability Year) and the rest of the state (\$85/kW).

Therefore, a transmission project that reduces the New York City locational capacity requirement would save the City’s load-serving entities \$74/kW per year in capacity payments.

Under FERC’s SMD, there is a principle that those who create such benefits should be paid for them. But under current practice, the only payment that a merchant transmission investor would obtain is the payment for transmission services. In the case of an AC project, as already noted, that payment would be denominated in terms of CRRs or FTRs or TCCs. In the case of a DC project, it should be possible to sell capacity services across the line as well, significantly enhancing the value of the project to a load-serving entity in a load pocket.

Given these facts, in a power market like New York’s where locational capacity requirements and “capacity demand curves” (or their functional equivalents) exist, merchant transmission projects that reduce such requirements should also be awarded “Locational Capacity Reduction Payment Rights,” equivalent to the magnitude of the reduction in megawatts times the spread between the cost of capacity in the load pocket and in the rest of the market.

We will return to this proposal (first issued by ESAI in March 2003) later in this report. But first, we have to review the issue that has led to yet more redefinition of how merchant transmission facilities will be built.

The Third Image of Merchant Transmission: LSE or Other Sponsorship

The question now is whether the refinement of the merchant transmission model – what we have been calling the second image – will suffice to stimulate new projects quickly. Ideally, merchant projects would sprout like mushrooms once the issues involved in developing the first and second images of merchant transmission are resolved.

Initial indications are that more is needed, that we need to move towards a third image. The events of the last five years have left investors with a high awareness of two factors that will strongly inhibit investment: regulatory risk and liquidity risk. Regulatory risk is an enormous and variable problem. It runs the gamut from concern that any profits

made from merchant assets will be under the cloud of suspicion created by the continuing aftermath of the California debacle to the “no good deed goes unpunished” syndrome, where load-serving entities find it difficult to make any financial commitment to secure new supply for fear of being punished by their public service commissions some time in the future.

For these reasons, early investors are likely to want an industry participant to sponsor at least in part the merchant transmission line by signing up for its transmission services for some considerable number of years. The ideal case is supply-push, where a supplier has such a competitive cost advantage that it is willing to pay for the cost of transmitting its power into markets it otherwise could not reach. That is, after all, the classical model whereby Hydro Québec financed all of the very significant DC transmission infrastructure that takes power from Quebec to New England and New York.

The mirror image of the supply-push deal is demand-pull, where a load-serving entity committed to an urban market makes the commitment to enough of the transmission line to make it possible to finance its debt portion, leaving the rest of the risk to be borne by equity investors. The capacity of the Transenergie Cross Sound Cable, for example, was purchased entirely by the Long Island Power Authority (LIPA), a government-backed load-serving entity.

There are very few LIPAs, however. In many areas, there is a vacuum in the market created by the demise of the marketing companies. They served, as we have noted in another place, *in loco parentis* for consumers. Because so many load-serving entities decided they were not willing to participate in the marketing of power to end users, preferring instead to remain regulated “T&D” companies, it was the Enrons, Williamses, and Dynegies that were willing to make the long-term commitments that enabled power plants to be built in the project-finance mode. *Now these entities are gone, (or at least absent from the investment arena) and the load-serving entities are likely to remain default service providers indefinitely.* Few of these reluctant LSEs, however, are willing to make long-term commitments to new projects.

Yet under the proposed requirements of FERC’s standard market design, LSEs will have a clear obligation to arrange for sufficient capacity to meet their load. The trouble with this formulation is that many load-serving entities are serving under protest, so

to speak, while waiting for new, merchant, retail entities to emerge to serve load, as promised by the early advocates of deregulation.

Very little progress has been made in this area. In some places, electric customers continue to get their power under a variety of standard offer arrangements or default service obligations. In other areas, load-serving entities choose to satisfy their capacity obligations by means of relatively short-term contracts, even as it becomes evident that investor's appetite for building new generation or transmission capacity without *some* long-term commitments from customers is weak at best.²⁹

There is, in other words, an impasse: investors unwilling to finance power plants or transmission projects without some form of long-term power or capacity purchase agreements from credit-worthy sponsors and (with the exception of a few special cases) the only remaining sponsors (LSEs) unwilling to make that commitment because they had planned to exit the energy procurement business. As long as this impasse lasts, the pace of new merchant transmission development is unlikely to accelerate.

Because of this impasse, a search for merchant transmission projects to be completed in 2002 or 2003 or 2004 or 2005 yields very little. Compared with thousands of megawatts of generation, there are new transmission projects amounting to only some 200 miles, a drop in the bucket of what is required.³⁰

Déjà Vu for the LSE: No Good Deed Goes Unpunished

The first step in answering that question is addressing who is responsible for meeting the energy needs in the load pocket. In many urban markets, meaningful retail competition is developing very, very slowly, which means that if the incumbent load-serving entities do not take responsibility for promoting the development of adequate generation or transmission capacity, it may not get done. This illustrates one of the key concerns with FERC's emphasis on LSEs to ensure adequate resource capacity. The

²⁹ It is in this context that the power market will miss the major marketers the most. From 1995 to 2001, these are the firms that acted, in a sense, as the consumer's agent by virtue of their willingness to sign long-term power purchase deals with power plant developers. Those deals are now under review and attack, but because they were marked to market against phony forward curves, they are deemed to have little value. That is, of course, a mistake: They have little value in today's market because there are no buyers. They will have huge value in the future because today's buyers will buy them at a significant discount.

³⁰ Using numbers from the North America Electric Reliability Council *2001/2002 Winter Assessment* as a guide

country is full of reluctant LSEs, entities that are trying to figure out their future given the regulatory uncertainty and that are therefore extremely reluctant to sign the 20-year power purchase agreements necessary to finance new power projects. This is, to be sure, a transition problem, but the transition in this case may take 10 years.

During this awkward interim period, the “default” LSEs will be living under what is called the “no good deed goes unpunished” syndrome. If they make capacity commitments for 20 years that look ill advised a few years later, they may not get approval to pass those costs on to their customers. In this worst-case scenario, the continuing regulations on retail rates will cap the returns on the capital committed to the transmission project, but the potential losses to shareholders will not be capped if, one day, the Public Service Commission deems the commitment to have been imprudent.

Yet, without a significant commitment from an LSE, it is doubtful any significant new merchant transmission or generation investment will be made. The days when a Williams or Mirant or Duke would build a power plant (or sign a long-term tolling agreement) “on spec” or sign a 20-year transmission deal are over. Many of these companies have paid huge penalties for their daring and will now become models of conservative behavior.

In sum, the effects of this restrictive financing environment will be most significant in solving the capacity problem in areas – such as the load pockets of New York – that missed out on the generation construction boom of the 1990s and early 2000s. For these areas, the LSEs will have to *cause* generation and or transmission facilities to be built by making long-term financial commitments that the developers can take into a skeptical and selective financing market.

The general malaise in the financing community and uncertainty over when and how FERC’s SMD initiative is implemented will cripple private investment in generation for years, to the detriment of maintaining adequate reserve margins, especially in load pockets. Private generation investment, in short, will not solve the load pocket capacity issue.

This puts LSEs – and those who regulate them – back in the drivers seat, whether they want to be there or not. Moreover, it puts them in a position to pick winners and losers: DC transmission, wind power, local CCGTs, demand management. This is unques-

tionably a retreat from the world that might have been had the vision of the Enrons, Williams and Dukes come to fruition. But it has not.

In summary, to live in this halfway regulated, halfway unregulated world safely and reliably, some LSEs – mostly those in load pockets – need to make some long-term commitments. As they do so (and many will have no choice but to do so), they will implicitly and automatically build a bridge between the regulated world and a future, more market-oriented world that we all realize now will take a decade to develop.

Providing Baseload Merchant Transmission Revenue Streams

So far, this discussion has taken the principles of the PJM/SMD policy, added some New York capacity market features and asked whether and how merchant transmission projects could be developed. We have argued that such projects will not be developed only from CRRs, nor are we likely to see the kind of indiscriminating investment from the power marketing companies in transmission that we saw in generation. As a result, we believe load-serving entities will need to play a role in providing some “base load” revenues for merchant transmission projects.

We have identified the ingredients for the successful stimulation of merchant transmission projects, at least into load pockets. We need to combine (1) an enduring energy spread between a load pocket and “nearby” (from a transmission standpoint) well-supplied areas, (b) a “capacity spread” between the same markets, and (c) a locational capacity requirement defined in such a way that a new transmission line reduces it with (d) a load-serving entity that is certain enough of its place in the market and its responsibility to its customers to write a 10- or 15-year contract for either the capacity benefit or the locational capacity reduction benefit or both. It would certainly help if that LSE had at its side a Public Service Commission that understood the need to provide a degree of base revenues to the merchant transmission project. Finally, fair and balanced treatment of the merchant transmission project by the ISO/RTO/IPT is essential, and is a steady and brave FERC.

To put a final and business-like conclusion to this review, we will ask the key question for financing: What are the firm and variable revenue streams of a merchant transmission line? It depends in the first instance on whether it is DC or AC. A DC line

provides a controllable flow of energy and capacity services; an AC line that is part of a network provides transfer capacity between connected nodes whose quantum is determined by many other variable factors on that network. Thus, a DC transmission line can sell firm point-to-point service (assuming it has a firm connection to the AC system); an AC line cannot sell firm point-to-point service.

For that reason, the revenue streams of a DC project will include the sale of energy (the value of which will be influenced by the prevailing and forecast energy market spread between the interconnected areas), capacity services (again, influenced by the size of the capacity market spread), and the ancillary services (also influenced by the spreads in ancillary service markets), to the extent the rules of the markets allow those spreads to be captured. In addition, if a DC project incurs interconnection costs in the AC system, such investments may increase the transfer capacity into the export bus, which may generate FTRs/CRRs that also have some financial value. Finally, to the extent a DC project improves overall system reliability (defined as decreasing the probability and scope of interruptions like the Northeast Blackout), it should receive some payment for that service.³¹

There are a number of unresolved questions here that will impede investment, and one of the key ones is *what are the revenues associated with the CRRs?* The project's *pro formas* will need to have at least a ballpark estimate of the number of revenue dollars that this added investment would generate. But the developer will not get the "official" ITP estimate of CRRs until the end of the system impact study process. Once the developer knows how many megawatts of CRRs the interconnection investment will generate, he may be in a position to estimate the number of dollars the CRRs will generate over time.

The assessment of the value of a CRR revenue stream will be difficult. That is, of course, a statement that should be applied to any investment. But there is a real concern that investors – already spooked by the meltdown in the generation sector – will find the

³¹ "If an entity pays to construct new generation or transmission facilities that add transfer capability, and the costs of the upgrade are not rolled in, the entity would receive the Congestion Revenue Rights associated with the new transfer capability. In the past, the Commission has allowed credit for upgrades. Is there still a role for credits under Standard Market Design?" NOPR at para. 238.

economics of CRRs a bit forbidding. The developer will have to find a way to make them understandable to the investment community.

While the CRRs associated with a DC project may be incidental (though too large an interconnection cost can sink a DC project as easily as it can sink a generation project), they will be central to the economics of an AC transmission project. Indeed, under current PJM rules, AC projects will rely entirely on CRRs developed and estimates of the values of CRRs as sold through the CRR auctions. Until there has been substantial experience with this kind of transmission investment, it is difficult to imagine successful development of merchant AC projects.

Proposal For “Locational Capacity Reduction Rights”

However, under the emerging rules of the New York ISO (see previous section’s discussion on locational capacity requirements and capacity demand curves), ESAI has argued that merchant AC transmission projects that reduce locational requirements should be awarded “Locational Capacity Reduction Payment Rights,” equivalent to the magnitude of the reduction in megawatts times the spread between the cost of capacity in the load pocket and in the rest of the market.

For example, suppose a 600-MW merchant AC line reduces the NYC in-City capacity requirement by 400 MW and that the “capacity spread” is \$74-kW/yr. In this case, the AC project would obtain a long-term contractual payment of \$29.6 million/yr ($400 \text{ MW} \times \$74/\text{kW} \times 1,000$).

In this way, the “Locational Capacity Reduction Right” would allow merchant transmission projects to capture the value of their contribution to the capacity markets. As such, it would be appropriate for them to be paid in the form of relatively long-term contracts between the load-serving entities that have the capacity obligation and the transmission developers. Such long-term contracts, in turn, would form the basis for the debt part of the financing of the merchant transmission lines.

In addition to the “Locational Capacity Reduction Rights”, the AC merchant line would be allocated CRRs (a.k.a., TCCs, FTRs), which are monetized in the energy (and

not the capacity) market. Because these are volatile revenues, it would be appropriate for equity investors to finance this part of the merchant transmission project³².

Taking the fixed (LCRR) and the variable (CRR) revenue streams together, we can imagine a *pro forma* for an AC transmission project. Assume a 600-MW AC expansion into New York City costing \$300 million. Assume it reduces the LSEs locational capacity requirement by 400 MW and that the “capacity spread” with the rest of the state is \$74 kW/yr. Assuming a 20-year project life, the \$74/kW payment would provide two-thirds of the required cash flow to finance the project on a merchant basis.

The remainder would be “CRR revenues”, which would be “at risk” money suitable for equity investors. To make the project financeable, the energy spread in the day-ahead market between the City and whatever nodes upstate would be chosen for the TCC calculation would have been deemed to be large enough by investors to make it worth their while.

The Rising

Unless FERC finds a way to get Congress to impose SMD via legislative decree – a most unlikely prospect in 2003, even after the Northeast Blackout – it appears that there will continue to be a variety of electric market designs competing for approval in the United States (and Canada, which has its own varied set of experiences). PJM may be able to expand, albeit slowly. New York will remain a single market – no Northeastern RTO is in view -- but it is committed to much of the SMD model and its policy model remains instructive for other areas that have deep load pockets. New York will block New England’s potential merger with PJM, leaving New England to figure out how to make a market with Atlantic Canada. That leaves Quebec in the enviable position of arbitraging virtually the entire northern part of the Eastern interface.

In the Midwest, the MISO and SPP mergers with PJM are unlikely to go forward on the announced schedule. Opposition from the confederacy of the regulated is too entrenched to overcome on a schedule rapid enough for PJM, which will prefer to annex

³² In New York, the ISO has taken a step towards this by implementing a “UDR” (unforced deliverability right) – but this applies to controllable lines only and was designed to accommodate the first wave of merchant transmission projects, which have all been DC.

smaller pieces of the Midwestern and Southern markets. In the far West, California will remain the Russia of electricity: ungovernable in spite of a plethora of natural endowments. It will take a decade for voluntary capital to return to that market, meanwhile the utilities – already struggling to recover from bankruptcy – will have to provide the PPAs to get generation and transmission projects built.

This potpourri of market environments is precisely what FERC sought to avoid, but it is here nonetheless and this fact will not be changed in spite of the Blackout and the millions of pages of comments about the SMD that are accumulating on the FERC website.

And from the ashes of the original intention to create a small number of effective mega-power-markets, one banal fact will stand out to businesspeople interested in transmission: *Electricity prices are very, very different, and there is therefore an opportunity to make investments in transmission.* The PJM model shows us average zonal energy price differences that are, at most, \$5/MWh between the cheapest and the dearest zone while the New York model shows us average annual zonal energy price differences well in excess of \$10/MWh. Few other pools/RTOs will be as closely knit as PJM, so one should expect Midwestern, New England, and the southern and western pricing differences to look more like those of New York than like those of PJM. And because there will be more market areas than FERC had originally intended, *there will be more inter-market seams and investment opportunities for new transmission development.*

Given all that has been spelled out in the preceding pages, how can we stimulate both economic and reliability transmission?

We take as a given that RTOs will take care of reliability investments *within their service areas*, and that the Blackout will accelerate efforts to deal with the *reliability aspects* of RTO seams. RTOs will find that tackling economic transmission projects will consume vast amounts of resources and political risk and will therefore remain focused on “reliability” projects.

“Economic” transmission development will occur along two different paths: (1) DC projects will be aimed at load pockets, places where cheap energy is bottled up, and at inter-RTO seams; (2) within RTOs, merchant developers and their investors will tackle

AC opportunities *if* the kind of policy reform discussed here (the “locational capacity reduction payment right”) is implemented to provide baseload revenues.

From a policy standpoint, independent transmission projects will be built first where there is locational pricing, where there is some baseload revenue like “LCRPR” suggested in this paper, and/or where load-serving entities or low-cost power providers are willing to sponsor the projects. Without locational price information, investors have little basis on which to invest the billions of dollars in new transmission facilities, which is the goal of federal electricity policy. Where LMP cannot be imposed, transmission investments will have to be made the old-fashioned, regulated way.

Where FERC’s SMD and the accompanying LMP regime is implemented, its price signals should mobilize – to borrow Bruce Springsteen’s latest album title – “The Rising” of transmission development as a new industry.

It is intriguing to speculate about where we will be in 30 years – will there be a few large or dozens of smaller Transcos dominating the transmission landscape. Will they be largely “for profit” or “not for profit?” Will their investments be aimed mostly at reliability, or will they aggressively pursue the destruction of all zonal energy price differences? Will merchant lines have bridged the major seams and load pockets? Will there be robust secondary markets in “transmission scheduling rights” across these lines?

At the moment, all that is clear is the competition for attention by entities positioning themselves to be key players. As things stand today, the key players are a few for-profit Independent Transmission Companies (like Transelect, Translink, and the American Transmission Company), some not-for-profit ITCs that may survive in some jurisdictions and where public power may play a particularly important role (like Georgia Power), RTOs that are at least considering managing transmission investments themselves with no specific need for a regional, monopoly Transco (PJM, NY-ISO, Nepoch, and the emerging California, ERCOT, Grid South, and MISO RTOs), and a very small number of transmission Developers (Transenergie and Neptune Regional Transmission System).

Obviously, FERC and state regulatory agencies will have a lot of influence over which of these models and businesses prevail and where. We believe there is little appetite for a completely non-competitive solution – e.g., a nation-wide Gridco. Instead,

FERC and the majority of state regulators will do what they can to empower trustworthy entities for the reliability part of the equation, and to entice merchant entities through a variety of regulated incentives (ultimately including rate-based investments paying a regulated, perhaps augmented, rate of return) and approvals to develop unregulated transmission assets in locations where it is not appropriate to socialize or rate-base the cost of the asset.

It is fashionable today to complain that the power sector is a mess and its assets a bunch of lemons. The Blackout may make it even worse in the short run by making the Grid look like it is being run by the Keystone Cops. But in time the fog will clear and the market-pricing principles that have been successfully introduced in the Northeast will be the centerpiece of an effective transmission development policy.

There is work to do, but it is not to develop some kind of a command and control national “transmission plan.” Instead, it is to allow FERC’s market designs to continue to evolve where they are politically acceptable (which we believe is most of the country). We need to augment the SMD platform with innovative ideas that provide financial reward to projects that help control inter-seam flows, that properly pay for benefits incurred such as decreasing locational capacity requirements, that allow independent transmission companies to join RTOs and participate in the planning process, that empower load-serving entities to make appropriate commitments without create a new “PURPA of transmission.”

Finally, we may need some tax incentives in the short run to make skittish capital commit to independent transmission development. If so, it should be designed as a “pump-priming” activity and retired as soon as possible, because the essence of power market reform in the last ten years has been to empower this industry to *transcend* its historic fully-regulated status. The Blackout is a reminder that electricity’s reliability requirements are critical and call for an intelligent synthesis of regulation and respect for market forces.