Electricity Market Structure and Infrastructure

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A key challenge for electricity market design and regulation is to support efficient investment in infrastructure. A review of the transition in the electricity system provides a foundation and framework for an agenda for action, primarily at the Federal level. Examples of resource adequacy and transmission investment illustrate a key requirement to relate any proposed policies to the larger framework and to ask for alternatives that better support or are complementary to the market design. Many seemingly innocuous decisions appear isolated and limited, but on closer inspection are fundamentally incompatible with and undermine the larger framework. A workable regulatory and market framework is an essential tool for anticipating unintended consequences and acting in time.

Introduction

Infrastructure investment is a common focus of energy policies proposed for the United States. Initiatives to improve energy security, meet growing demand, or address climate change and transform the structure of energy systems all anticipate major infrastructure investment. Long lead-times and critical mass requirements for these investments present chicken-and-egg dilemmas. Without the necessary infrastructure investment, energy policy cannot take effect. And without sound policy, the right infrastructure will not appear. Acting in time to provide workable policies for infrastructure investment requires a framework for decision that identifies who decides and how choices should be made.

Infrastructure investment for the electricity sector in generating plants, transmission lines, distribution wires, control systems, metering and end use devices is an important part of the larger picture. The electricity sector is capital intensive and under any reasonable forecast requires substantial investments. Choosing which investment to make, and who should pay, can be controversial. The controversies are compounded by the continuing transition in electricity to restructure the balance between markets and regulation, between incentives and central planning, between risk and reward.

The purpose here is to outline the major investment policy challenges for the electricity sector in light of this electricity restructuring transition. Notably there is an important role for government, through regulation and centralized coordination, and for markets, through incentives and innovation. Implementing a workable balance between the role of government and the contribution of markets requires looking ahead to act now to reinforce rather than undermine long-term goals. Special features of the electricity system interact with more general energy problems to make this balancing act a formidable challenge. There are several stands that have to work together. Actions now must look ahead to avoid unintended consequences that could unravel the larger fabric.

Investment and Uncertainty

The North American Reliability Corporation (NERC) provides annual assessments of the outlook for reliability of the electricity system. The assessments provide a broad overview of the electricity infrastructure and expected investment. According to NERC's most recent assessment, the United States will add 123 gigawatts (GW) of new capacity between 2007 and 2016. [1] This compares, for example with the 100 GW capacity of the existing nuclear fleet. However, the expectation is that most of this new capacity would be coal and natural gas with a small contribution from other technologies. In addition NERC anticipates over 14,000 circuit miles of additions to the high voltage power grid.[2] These would be substantial investments, but even with this outlook NERC reports that "industry professionals ranked aging infrastructure and limited new construction as the number one challenge to reliability—both in likelihood of occurrence and potential severity." [3]

From one perspective, this pace of investment looks quite manageable. Total installed capacity of generating plants is now over 1,000 GW, so the expansion of 123 GW over a decade is only about twelve percent. This compares with the 281 GW of new capacity investment, primarily in natural gas plants, that entered the system over the seven years from 1998 to 2005.[4] Similarly, the expanded transmission investment is less than ten percent of the existing 163,000 circuit miles. In the aggregate, therefore, the investment needed to meet the expected growth in demand seems well within our capabilities.

However, the aggregate figures hide regional differences that give rise to concern and a need for further investment. "Areas of the most concern include WECC-Canada, California, Rocky Mountain States, New England, Texas, Southwest and the Midwest." [5] Furthermore, the choice of fuel and technology presents significant difficulties in deciding on the portfolio of investments. "The unique characteristics and attributes of renewables require special considerations for planning. For example, they are often

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[1] North American Electric Reliability Corporation (NERC), "2007 Long-Term Reliability Assessment, 2007-2016," Princeton, NJ, October 2007, p. 10 (www.nerc.com).

[2] NERC, 2007, p. 18.

[3] NERC, 2007, p. 19.

[4] North American Electric Reliability Council (NERC), "2006 Long-Term Reliability Assessment,," Princeton, NJ, October 2006, p. 31 (www.nerc.com).

[5] NERC, 2007, p. 10.

remotely located, requiring significant transmission links often over challenging terrain."[6] A national policy to transform the electricity sector would compound these difficulties.

In addition to the regional variation, there are the substantial uncertainties that cloud investment decisions. Electricity generating plants differ in important ways that complicate the selection of technology. For instance, in its development of the Annual Energy Outlook (AEO), the Energy Information Administration (EIA) considers generation technologies that range in initial capital cost from a low of $450 per kilowatt (kW) for advanced combustion turbines, to $1,434 per kW for scrubbed coal, and $2,143 per kW for advanced nuclear. Similarly, the expected (and optimistic) construction times are two, four and six years respectively.[7] The capital cost numbers illustrate the range of choices but substantially understate current estimates of the level of such costs at more than double the EIA planning assumptions, reinforcing the point of considerable uncertainty.[8] When construction time is added to planning and permitting, the lead times could extend out for a decade. On the demand side, the array of possible technologies and usage patterns is highly diverse, and technology is changing rapidly. This creates many other opportunities to exploit, with a great variety of costs and impacts.

If these figures were known with confidence and the future were easily predicted, this great variety in costs and planning horizons would not present much of a problem. Small errors would be temporary and overtaken by growth in demand. However, the reality is that there is great uncertainty that confounds the forecasts and infrastructure investment planning.

The connection between investment and uncertainty arises because of the long lead times and long lives of infrastructure investments. Were the uncertainty simply random variation, the cost would be clear and the prescriptions would call for diversification, hedging, and more but smaller investments. However, the uncertainty that affects the energy system is not just random variation. The rapidly changing policy and economic system, with the constant flux of technology innovation, produces information about opportunities and risks that call out for a different way of making investment decisions. The balance shifts away from an emphasis on central planning and the judgments of the few to the more dispersed wisdom of highly motivated crowds that are bearing the risks and reaping the rewards. A challenge in policy for the electricity system is to craft and sustain this change in balance given the large uncertainties ahead.

One way to develop an appreciation for the degree of uncertainty is to look at our record from the past. The EIA has been publishing its annual outlooks for many years. The methodology and knowledge applied have changed with accumulating experience, but there is enough stability in the people and processes to give some reason to compare the results of the forecasts and the actual events. The EIA publishes regular retrospectives, and the forecasting horizon for which we have the most data is a seven year projection.

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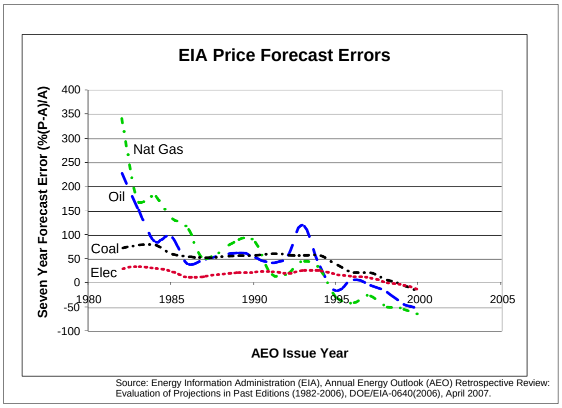
[6] NERC, 2007, p. 13.

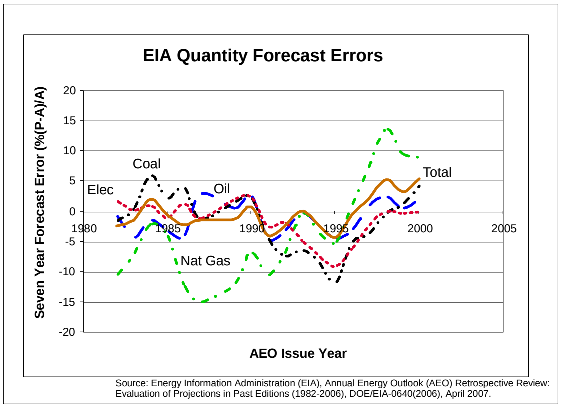
[7] Energy Information Administration, "Assumptions to the Annual Energy Outlook," Washington D.C., 2008, p.79.

[8] FERC Staff Report, "Increasing Costs in Electric Markets," June 19, 2008, (http://www.ferc.gov/legal/staff-reports/06-19-08-cost-electric.pdf.)

Seven years is not a long time in the electricity infrastructure investment cycle, with many decisions that depend on much longer horizon outcomes.

The accompanying figures summarize the EIA record for the seven year forecast error as a percent for key prices and quantities over almost two decades of publication experience. The EIA is highly professional and serious. For those familiar with these matters, the forecast errors are not surprising, and perhaps less than expected. But these errors over a relatively short horizon for prices are considerable, and reflect the difficulty made evident





by the unanticipated rise in prices in 2007-2008 when oil went to $140 per barrel. For the quantities, there is more stability, but the range of errors is still large and of the same order of magnitude as the forecast infrastructure investment described in the NERC assessments.

A high degree of uncertainty arises in part because of the uncertainty in energy policy going forward, over which the government has some control, and in part because of the inherent unpredictability of economic events.

Concerns with policy uncertainty are easy to find. For example, the pressure to address the challenge of climate change and carbon emissions is building with the expectation that there will be controls and a price on carbon. Since the whole purpose of pricing carbon and controlling emissions is to dramatically change the portfolio of investments, it should not surprise that the policy uncertainty complicates investment infrastructure planning.

A broad analysis of the impacts of policy uncertainty can be found in a recent study conducted by the International Energy Agency (IEA) reviewing the experience in developing electricity markets across the IEA member countries.[9] The comparative experience shows ample evidence that with the right conditions the necessary investments will be made. "Experience to date shows that, with the right incentives and with a stable investment climate, investors are responsive to the needs for new generation capacity. When signals are undistorted in effectively liberalised markets and companies

[9] The IEA member countries are: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, the Republic of Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States.

have incentives to compete, investors respond to market signals and have so far added new capacity on time."[10] However, the same analysis emphasizes the importance of dealing with the high level of uncertainty confounding investment decisions.

The IEA's extensive comparison across countries and its advice to governments are relevant to the U.S. government and, especially, the Federal Energy Regulatory Commission (FERC) with its responsibility to oversee wholesale electricity markets. The IEA report provides a lengthy analysis to support "key messages" that summarize the conclusions. These summary points include:

- "*Governments must ensure a stable and competitive investment framework that sufficiently rewards adequate investments in a timely manner.*— Considerable investment in new power generation will be required over the next decade to meet increasing demand and replace ageing generation units. Current trends suggest a significant risk of under-investment. Long project lead times and high investment costs, particularly for large base-load units, create a need for government action to reduce uncertainty in the very near term. Efficient use of existing resources is particularly important at this stage, as it allows for lower margins and buys time to meet investment requirements.

- *Governments urgently need to reduce investment risks by giving firmer and more long-term direction on climate change abatement policies.*—Putting a price on greenhouse gas emissions is an effective way to internalize the costs of climate change. Direct financial support for specific technologies, such as renewables and nuclear, should be done at the lowest cost and with market-compatible instruments. Market-based instruments, such as tradeable obligations systems, have many advantages; direct subsidies, such as tax credits, can also be implemented in ways that are compatible with competitive markets. Nuclear power will only play a more important role in climate change abatement if governments in countries where nuclear power is accepted play a stronger role in facilitating private investment.

- *Governments should pursue the benefits of competitive markets to allow for more efficient and more transparent management of investment risks.*— Competition in well-designed and effectively liberalised markets creates incentives for efficient use of resources and investments in power generation. However, in order to deliver its anticipated benefits, liberalisation requires whole-hearted implementation and long-term commitment by governments. Competition cannot always stand alone. When necessary, governments should pursue intervention in ways that complement the market and facilitate its functioning.

- *Governments need to ensure that independent regulators and system operators establish transparent market rules that are clear, coherent and fair.*— Transmission system operators hold the key to competitive electricity markets and must be effectively separated from generation and retail supply. Unified

[10] International Energy Agency, Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience, Paris, 2007, p. 13.

regulation and unified system operation should be pursued as tools to facilitate dynamic trade across borders and efficient sharing of reserves.

- *Governments must refrain from price caps and other distorting market interventions.*—Wholesale electricity prices are inherently volatile and price spikes are an integral part of a competitive market. Price caps, regulated tariffs that undercut market prices, and direct market intervention seriously undermine market confidence, jeopardising efficiency and reliability. Governments can best address systemic market power abuse by: improving market design; strengthening competition law and competition regulators; and diluting the dominance of large players. Demand response constitutes an essential but still poorly exploited resource, and must receive specific attention in the development of market design and regulation. Increased installation of better metering and control equipment could considerably strengthen potential demand response resources. Capacity measures may be necessary if price caps are imposed. However, they are not a preferred solution to address market power and can easily become a barrier for the development of a robust market.

- *Governments must implement clearer and more efficient procedures for approval of new electricity infrastructure.*—Delays caused by slow licensing and inefficient approval procedures frustrate markets, and are serious barriers to timely investment. Governments must rebalance competing interests in favour of new electricity system infrastructure and offer clearer and more efficient approval procedures, preferably centred on one approval body. Timelines for approval processes must be clear and established in advance. Fast and efficient licensing is particularly important for new nuclear power plants which face very high risks as well as long planning and approval process. Early public debate is essential for the acceptance of necessary new infrastructure."[11]

Government can do something to reduce if not eliminate policy uncertainty. There is less that government can do to address the inherent uncertainty in economic events. Here, the issues center on who should decide and how decisions should be made, through planning or through markets, and how risks should be allocated, to captive customers or to market investors, to best address the many choices and the complications induced by the uncertainties.

Except for the climate change policy decision, under current United States laws and regulations, FERC has primary responsibility for setting and regulating the policies and practices needed to follow through on the IEA recommendations. Translating the general principles into practical rules and policies presents a major agenda for FERC.

A central problem for infrastructure investment is dealing with uncertainty and allocating the associated risks. The uncertainty is so large that it may be the most important variable, more than the forecasted central values. In addressing this decision and regulatory framework, a review of the electricity restructuring transition provides the

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[11] International Energy Agency, 2007, pp. 15-25.

setting for translating the key messages from the IEA that apply to the actions of government in the United States to advance the framework for infrastructure investment.

Electricity in Transition

The electricity sector has been experiencing a major restructuring of its infrastructure, institutions and choices. The old model was built around the principle of monopoly franchise with a regulatory structure that assumed a high degree of vertical integration and a reasonable degree of certainty. For decades following the consolidations associated with Samuel Insull in the early twentieth century, electricity companies built and operated their own infrastructure in the form of generating plants for producing power, high voltage transmission lines for moving power, and distribution wires for connecting with customer loads. Customer service was for full requirements, meaning that all electricity power and associated services were provided in a bundle by the electricity company. Customers had little or no choice as to who supplied their power. In exchange for this monopoly franchise, under the Insull framework electricity companies accepted extensive price and service regulation that controlled the rates charged to customers to reflect regulators' judgments about reasonable cost recovery and appropriate returns on capital invested.

The electricity system was never quite as simple as this stylized outline. There were always variations in the form of municipal and public power companies that differed from the investor owned utilities. But in its essence the combination of natural monopoly, vertical integration, full requirements service and rate regulation provided the template for industry organization. This framework had important implications for infrastructure investment. Primary responsibility for deciding on the pace and scope of infrastructure investment rested with the vertically integrated utility which had an obligation to serve the full requirements of its customers. The decisions made by management built on a central planning process that attempted to look long-term and invest ahead of growing demand for electricity. Regulators would review investments after the fact to judge the reasonableness of the expenditures and allow the costs of the new infrastructure to be included in the "rate base" that determined the prices charged to the final customers.

This system worked extremely well for many decades, with rapidly growing use of electricity coupled with declining average costs and rates. For the four decades before 1970, nominal electricity prices were declining or roughly level, and real prices were falling. Demand growth was large and predictable, averaging over 8% per year.[12] In retrospect, we attribute this happy outcome to the combined effects of technology improvements, exploitation of economies of scale and scope, and relatively predictable costs and technology. Regulators were in the position of approving expanded investments that would lower average costs and produce stable nominal and generally declining real prices for electricity.

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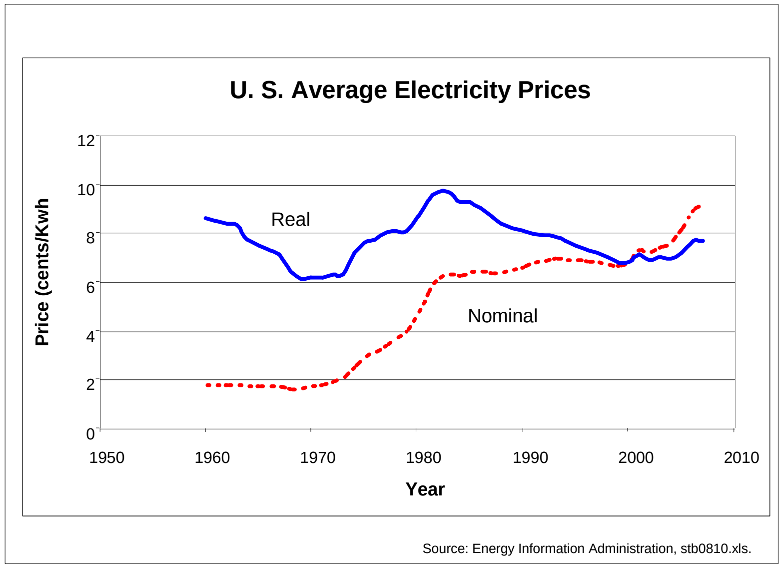
[12] Electric Utility Systems Engineering Department of the General Electric Company, Electric Utility Systems and Practices, ed. Homer M. Rustebakke, 4th ed., Chapter 1, "The Electric Utility Industry," Wiley & Sons, Inc., New York, NY, 1983, p. 4.

As summarized in the accompanying figure, the story changed in the 1970's. There appeared to be an exhaustion of the economies of scale that made new investment cheaper. Fuel prices rose in response to the oil price shocks and related energy crises that began with the first Arab oil embargo in 1973. Nuclear power plant costs started to rise and there were growing delays in plant completion, adding even greater costs and putting more pressure on the electricity industry. The results produced a reversal in the long-term trend in electricity prices. Both nominal and real electricity prices started to climb, with real electricity prices up more than fifty percent by the early 1980s. The nuclear accident at Three Mile Island in 1979, and the 1983 default on the bonds of the Washington Public Power System foreshadowed even further technical and financial problems that would unsettle the previously stable electric power system.[13] Thus began a period of turmoil and extended transition for customers, electricity companies, and their regulators.



There were two important implications for the framework for infrastructure investment. First, the easy days of adding new investments to rate base that lowered average costs were replaced by the need for regulators to approve increases in electricity rates, and this produced a new era of challenges and cost disallowances. No longer could the utility company be sure that the costs of major investments would be fully recognized and recovered. The resulting financial distress for many companies fundamentally changed the incentives and the willingness to invest in new infrastructure.

Second, the locus of decisions began to change. Before, planners at the electric utility companies made the choices for the generation, transmission and distribution portfolio of investments. The role of government centered on regulation of the resulting prices charged to the franchise customers. But legislation such as the Public Utility Regulatory Policies Act of 1978 (PURPA) began a gradual change in this division of

[13] On March 28, 1979, the Three Mile Island Unit 2 (TMI-2) nuclear power plant near Middletown, Pennsylvania suffered a partial core melt. Nuclear Regulatory Commission, Annual Report - 1979, NUREG-0690, Washington DC. In 1983 Washington Public Power Supply System defaulted on $2.25 billion of bonds due to inability to complete five nuclear reactors. "It was the largest municipal bond default in U.S. history." David Mhyra, Whoops!/WPPSS: Washington Public Power Supply System Nuclear Plants, McFarland, 1984, p. 1-2.

responsibilities.[14] Under Section 210 of PURPA, electric utilities were required to purchase power from "qualifying facilities" (QFs) at a price based on an administrative estimate of the utility's avoided costs. Although seen initially as a modest intervention to give a boost to the small power plants and cogenerators that made up the QFs, the PURPA provisions and related initiatives in New York and California had a profound effect. As intended, the response from the competitive new entrants in small power and cogeneration demonstrated that they were more than capable of building and operating power plants. As not intended, the experience demonstrated that government planners were fully capable of selecting high cost new investment that compounded the problems of the industry.[15] The planners' avoided cost estimates were so high that they produced both too much new supply and too great an increase in total costs. By the early 1990s, the first phase of the electricity transition had solidified an interest in finding some other way to organize the industry, drive decisions, assign risks, and govern expansion of the electricity infrastructure.

A new approach came on the scene following from the experience in other industries and other countries. The natural monopoly argument, at least for electricity generation, was overtaken by events. With no new economies of scale, and with the growth of the QFs, it became plausible to argue that electricity generation need not be treated as a natural monopoly. Opening the electricity market to competition seemed possible and would provide an alternative means to monopoly and regulation to enforce efficient investment and operating decisions. Although this argument applied directly to wholesale competition and the production of bulk power supplies, similar arguments were applied to retail competition and creation of customer choice with unbundled energy services.[16]

The new idea was that like airlines, trucks and natural gas, complete regulation of vertically integrated monopoly franchise electricity operations was not necessary, and a better way would be to shift more towards relying on competition in electricity markets. The next phase in the electricity transition began at the Federal level with the Energy Policy Act of 1992 (EPAct92) and the introduction of wholesale competition.[17] Although EPAct92 explicitly excluded Federal preemption to extend competitive markets to retail customers, states from California to Massachusetts undertook various initiatives to unbundle generation, transmission and retail supply in parallel with Federal actions to expand competition in the wholesale electricity market. The provisions of EPAct92 had profound effects. The law expanded the scope of QFs by creating a new class of exempt wholesale

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[14] Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601 et seq.

[15] In 1981, New York law required payment of six cents per kilowatt-hour ($60/MWh) for QF power; N.Y. Pub. Serv. Law Section 66-c.1. In California, the QF "standard offer" solicitations at avoided costs were so oversubscribed that the California regulators sought coordinated procurement through the "Biennial Resource Plan Update" (BRPU) which required utilities to put their planned new generation out to bid. In the end, the regulators never approved new plant construction in the BRPU proceeding; Southern California Edison Company, et al., (1995) 70 FERC ¶ 61, 215, at p. 61,677. The collapse of the BRPU process played a prominent role in the move to reform electricity regulation in California.

[16] Energy Information Administration, The Changing Structure of the Electric Power Industry 2000: An Update, DOE/EIA-0562(00), Washington DC, October 2000.

[17] Energy Policy Act of 1992, Public Law 102-486.

generators (EWG), essentially power producers that could be either independent or affiliated with traditional utilities, but would be spared the usual restrictions under the regulations for utility holding companies.[18]

Most importantly, acting under EPAct92 authority FERC required existing electric utilities to eliminate undue discrimination and give third parties access to their transmission systems in order to facilitate wholesale trading and competition. Since in each region there is only one interconnected grid, it was clear that transmission services retained the features of a natural monopoly. Competition in generation and supply could not work without access to the grid and the ability to arrange transactions between producers and customers. Support of wholesale electricity market competition and transmission open access became national policy. However, implementing the abstract notions involved more than was anticipated.

Coordination for Competition

Passage of EPAct92 launched an extensive process of analysis and new regulatory initiatives to translate the abstract notions of open access and support of competitive markets into a workable set of new arrangements that would govern investment and operations. The largely unexpected result was that provisions requiring open access to the transmission grid to support wholesale market competition would fundamentally transform the regulatory and institutional structure of the electricity system.

Unbundling with eventual sale or separation of generating plants owned by existing electric utilities was simple in concept but difficult in practice. Following the reversal of the increase in other fuel prices in the 1980s, and widespread excess capacity in part because of the entry of QFs and reduced growth in electricity demand, the perception in many parts of the country was that the existing fleet of generating plants was uneconomic. A simple jump to open competition would drive down wholesale prices and leave the existing assets economically "stranded." This is a long story. During the days after passage EPAct 92, most policy discussion was about who would bear the costs of the stranded assets. In effect, although with different rules applied in nearly every state that undertook a major restructuring, the result was that the costs were shared with the greater portion born by customers. Whatever the merits of the sharing of stranded costs, the lesson for today is less about the allocations to different groups and more about the form of that allocation. In important cases, from California to Maryland, the structure of the rate deal was a long-term fixed price arrangement that was disconnected from the evolving market. Later when prices in the market rose, typified by the electricity crisis in California in 2000-2001, the structure of the rate deal was unsustainable. The political problems that followed illustrated the dangers of constructing an imbalance between markets and regulation. The unintended consequences were severe and almost fatal for the restructuring policy.

The ubiquitous and poorly understood role of transmission system operations presented an unusual and unexpected challenge. Unbundling of generation seemed conceptually

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[18] Public Utility Holding Company Act of 1935, Public Law 74-333 (PUHCA). The law provided for regulation under the Securities and Exchange Commission, and was an earlier reform designed to restrict the activities of utility holding companies. PUHCA was repealed with Energy Policy Act of 2005.

simple and straightforward. Less obvious was how to provide open access to the transmission grid. The states were responsible for the most important initiatives restructuring the ownership and reallocating the risks for generation infrastructure. However, the mandates of EPAct92 gave the Federal government responsibility to define the rules of transmission open access, with the bulk of the activity at FERC. There began an odyssey that was still incomplete more than a decade later. Through an extensive round of hearings and rulemaking processes, FERC examined most of the major issues that would determine the rules of open access. The core problem was deeply rooted in the nature of the transmission grid. As is often the case in policy development, a commonly held belief turned out to be seriously untrue. In this case, the false assumption was that there was a simple way to define a path in the transmission network along which power could be delivered from customer to generator, the so-called "contract path." If this were true, setting up the rules for open access wholesale market competition would have been relatively simple, possible emulating the rules that FERC had previously developed in the natural gas market. But if not true, FERC would need something else that might require a more radical change in institutions.

In its landmark Orders 888 and 889, promulgated in 1996, FERC produced a careful documentation and analysis of the dilemma.[19] As explained in Order 888, the "contract path" was a fiction at odds with actual operation of the transmission grid, where power actually flowed on every parallel path and every individual transaction could have a material affect on other transactions. However, FERC could see no available alternative and proceeded to adopt open access rules based on the fictional foundation of the contract path.[20]

When there is a vertically integrated monopoly, it matters only a little when the explicit rules for one part of the vertical chain do not conform to reality, because the monopoly has little incentive to act in ways that conform to the rules but are counterproductive in the whole. However, in the unbundled system without full vertical integration, the whole point of the system is for many different decision makers to act in response to the incentives in the sector, advancing the performance of the whole while seeking their own balance of profit and risk. It was clear that Order 888 and the contract path model would create chaos in a true open access market. In the event, NERC immediately implemented ad hoc transmission loading relief measures to undo the Order 888 schedules, but the NERC rules were widely recognized as inefficient.[21]

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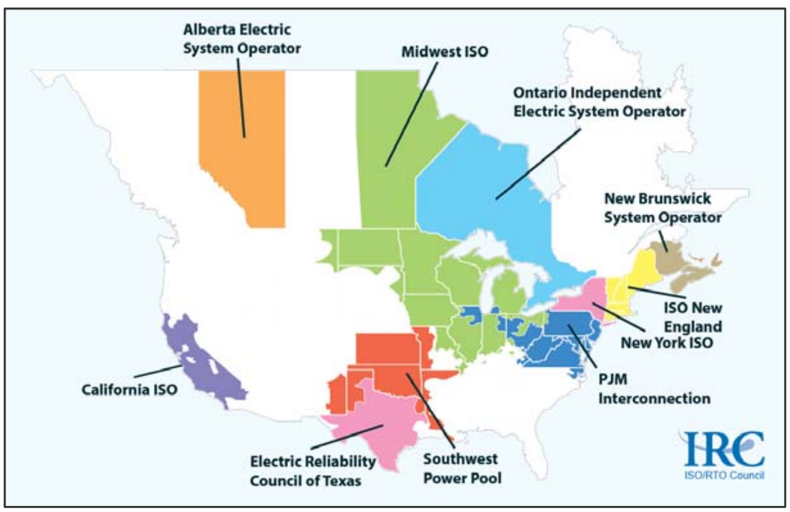
[19] Federal Energy Regulatory Commission, Order No. 888, Docket Nos. RM95-8-000 and RM94-7-001 "Promoting Wholesale competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," Final Rule issued on April 24, 1996. " Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct," FERC Order 889, Final Rule, Washington, DC, April 24, 1996.

[20] For further discussion, see William W. Hogan, Electricity Market Restructuring: Reforms of Reforms," Journal of Regulatory Economics, Kluwer Academic Publishers, Vol. 21, No. 1, 2002, pp. 103-132.

[21] Rajesh Rajaraman and Fernando L. Alvarado, "Inefficiencies of NERC's Transmission Loading Relief Procedures," Electricity Journal, October 1998, pp. 47-54.

The response across the country followed two basic approaches, and divided the country into two types of electricity systems. For most of the country, there was a major effort to organize markets in a completely different way. The basic idea was that a large region would recognize the strong interactions among the participants and create an Independent System Operator (ISO) or a Regional Transmission Organization (RTO) to handle all of the real time and some of the longer term activities in providing transmission services.[22] The market distinctions between RTOs and ISOs are not material here, and they can be treated as the same structure. After some experimentation, and the failure of the all alternative market designs, these organized markets under RTOs settled on the framework of an organized spot market using a bid-based, security-constrained, economic dispatch with locational marginal prices as the market foundation and substitute for the contract-path model. By 2007, all the RTOs in the United States were either already using or were converting to the essential elements of this framework.

As summarized by the IEA in its review of market experience across its member countries, "[L]ocational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments."[23] The operation of these markets by the RTOs is the essential ingredient that allows for competition and provides open access to the transmission grid. Through these markets, the RTO provides coordination for competition, allowing participants to arrange contractual commitments without producing energy schedules and an associated power dispatch disconnected from reality. The RTO market captures the interactions among the many market participants and prices them accordingly. Furthermore, the existence of the RTO market provides the framework to create workable Financial Transmission Rights (FTRs) that substitute for the unworkable physical transmission rights of the fictional contract path model.



The development of RTOs was impressive in its speed and scope. "These ISOs and RTOs serve two-thirds of electricity consumers in the United States and more than 50 percent of Canada's population."[24] Outside of the organized markets served by the RTOs, which covers a

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[22] Federal Energy Regulatory Commission, "Regional Transmission Organizations," Order No. 2000, Docket No. RM99-2-000, Washington DC, December 20, 1999.

[23] International Energy Agency, 2007, p. 116.

[24] See ISO/RTO Council web page at www.isorto.org.

large geographic area but a smaller part of the total economy and electricity system, the structure remains much as before with vertical integration or contractual arrangements between utilities and large public providers like the Tennessee Valley Authority in the Southeast and the Bonneville Power Administration in the Northwest.

The transformation of the organized wholesale markets was a major change in structure and market institutions that answered the unanswered questions in Order 888. The RTO experience illustrates a virtuous interplay between regulation and market design. The RTO structure is a creature of regulation, recognizing that a few critical activities essential for reliability must be centralized under monopoly control of the system operator. But the regulations and the structure are designed to internalize the problems that cannot be addressed by decentralized market decisions, dealing primarily with transmission interactions, while leaving substantial flexibility for operating and investment choices made by market participants responding to incentives and diverse views about risks and uncertainties.

Full implementation of the RTO markets designs remains a work in progress. But the preservation of the traditional structure in the rest of country presents a continuing challenge for the principles of open access. And there are more than a few difficulties in addressing the issues that arise at the seams between these various regions.

After much experimentation and lengthy debate, Congress revisited the issues of competition in the Energy Policy Act of 2005 (EPAct05). [25] This created important new authorities for FERC, such as making mandatory compliance with reliability rules that had been voluntary for decades. Voluntary compliance was plausible (but not guaranteed) under the old oligopoly, but mandatory rules were necessary in the environment of a competitive market. Furthermore, to improve planning and infrastructure development, as well as to address continuing problems of open access outside the RTOs and organized markets, FERC pursued further rulemakings to deal with transmission access and infrastructure expansion.[26]

This substantial transformation of organized electricity markets remains controversial. Partly as a result of the reaction to the California crisis of 2000-2001, and partly in response to the effects of the increase in all energy prices, there has been a continuing debate about the efficacy of electricity restructuring in general and RTOs in particular. Some criticize RTOs and suggest alternative market approaches.[27] Others add to the accumulating evaluations of the benefits of RTO markets.[28] FERC will continue to be a

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[25] Energy Policy Act of 2005, Public Law 109-58

[26] Federal Energy Regulatory Commission, Order 890, Docket Nos. RM05-17-000 and RM05-25-000; Order No. 890, "Preventing Undue Discrimination and Preference in Transmission Service," Issued February 16, 2007. Order 890-A, Docket Nos. RM05-17-001, 002 and RM05-25-001, 002, Issued December 28, 2007. Order 890-B, Docket Nos. RM05-17-003 and RM05-25-003, Issued June 23, 2008.

[27] American Public Power Association (APPA), "Consumers in Peril Why RTO-Run Electricity Markets Fail to Produce Just and Reasonable Electric Rates," Washington, DC, February 2008.

[28] Scott M. Harvey, Bruce M. McConihe and Susan L. Pope, "Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges," November 20, 2006 (revised June 18, 2007) and can be accessed at http://www.lecg.com/files/upload/AnalysisImpactCoordinatedElectricityMkts.pdf.

major venue for these debates, so the issue is relevant to the agenda for action going forward.

Here there are two arguments that get entangled and confounded. First, there is the effectiveness of electricity restructuring compared to the alternative of the monopoly utility structure it was intended to replace. This is an important question on its own and the evaluation should depend primarily on how the change affected investment decisions and innovation. Changes in operating practices with a given infrastructure are important, but unlikely to dominate the comparison. The big impact should be in changed investment choices for generation, transmission and load. The impacts here take time to unfold, and it would not be an easy matter to restore the monopoly structure.

Second is the question of how to design and regulate the market given the decision to implement electricity restructuring and change the locus of decisions more towards the decentralized market. Here there is now a great deal of information about what works and what does not work.

The centerpiece maintains a focus on open access and non-discrimination in transmission services as laid out as the objective in Order 888. Outside the organized markets and RTOs, the task remains largely unfinished. Inside the organized markets and RTOs, the task is mostly complete. Moreover every proposed alternative to the now accepted market design has been tried and found wanting. For example, a good way to put consumers in peril would be to follow recommendations such as those offered by the APPA.[29] This and similar calls to unravel RTOs would result in unworkable designs that might not even perform basic functions needed to support bilateral trading or manage congestion at least cost. The recommendation to resort to a simple contract-path scheduling system, with restrictions on RTO coordinated markets, merely recycles the failed Enron initiatives of the past.[30]

The ignorance of history reflected in these reform proposals may be unwitting. But the failure to explain how bad market designs would address the problems that coordinated RTO markets handle illustrates the dangers of regulation disconnected from reality. The costs of the market design mistakes have been substantial. They could have been avoided, and certainly do not have to be repeated. On the restructuring path, the emphasis should be on care in constructing regulations and market design to reflect the realities of how the system operates, and how market participants respond to incentives.

The accumulated effect of these many developments reinforced the commitment to create a new regulatory structure and rules to support open access and competitive markets. In reviewing the process, FERC has emphasized both the commitment and the challenge:

> “While competitive markets face challenges, we should acknowledge that competition in wholesale power markets is national policy. The Energy Policy Act of 2005 embraced wholesale competition as national policy for this country. It represented the third major federal law enacted in the last 25 years to embrace

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29 APPA, “Consumers in Peril … ,”, pp. vii-viii.

30 William W. Hogan, “An Efficient Bilateral Market Needs A Pool,” California Public Utility Commission Hearings, August 4, 1994, San Francisco, CA, available at www.whogan.com.

> wholesale competition. To my mind, the question before the Commission is not whether competition is the correct national policy. That question has been asked and answered three times by Congress.
>
> If we accept the Commission has a duty to guard the consumer, and that competition is national policy, our duty is clear. It is to make existing wholesale markets more competitive. That is the heart of this review: to not only identify the challenges facing competitive wholesale markets but also identify and assess solutions."[31]

In 2009 the agenda for electricity markets will include at least two main strands. First, there is the unfinished task of meeting the necessary conditions for transmission open access outside the organized markets of RTOs. For instance, one litmus test is providing open access to real-time economic dispatch for balancing markets, which is available in the organized RTO markets but not outside the RTOs.[32] Second, there is the continuing challenge in the organized markets of refining the market designs and addressing remaining problems that can be of particular importance in the development of electricity infrastructure.

Regulation, Markets and Investment

Electricity restructuring has never been about deregulation or complete reliance on markets. Given current technology, it is not possible to neglect the requirements of coordination for competition. There is a need for regulation of the remaining monopoly elements of the electricity system, most importantly in system operations, scheduling and dispatch. In a sense, this makes the task harder for regulators. It is one thing to oversee vertically integrated monopolies and judge the reasonableness of operations and investment decisions. It is quite another matter to fashion the rules for many different generators, transmission owners, customers, and the system operator to facilitate reasonable market decisions. And for important cases, market driven investment may be insufficient. In these cases some infrastructure investment decisions may still need to be made by central planners and regulators. The challenge is to formulate rules for making these decisions, rules that must work in conjunction with market choices without the unintended consequence of unraveling the market.

A fundamental task is addressing the uncertainty that confounds investment decisions. As discussed above and as emphasized in the IEA review, there are many elements of policy uncertainty that government can control, at least to an extent, and it is important to establish a workable future regime. However, certainty is not the end in itself, and a workable regime that has staying power over a long period must be compatible with reality of how the system works and with the goal of supporting competition in wholesale power markets.

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[31] Joseph T. Kelliher, "Statement of Chairman Joseph T. Kelliher," Federal Energy Regulatory Commission, Conference on Competition on Wholesale Power Markets AD07-7-000. February 27, 2007.

[32] John D. Chandley and William W. Hogan, "Reply Comments On Preventing Undue Discrimination And Preference In Transmission Services," Comments to Federal Energy Regulatory Commission, Docket Nos. RM05-17-000 and RM05-25-000, September 20, 2006. (www.whogan.com)

The broader government energy agenda includes a variety issues related to climate change policy and development of new resources. The associated tax and incentive polices present their own challenges, and go well beyond the scope of electricity market design and infrastructure investment rules. The framework for market design decisions falls principally within the domain of FERC and will be critical for the success of any policies. The challenges for FERC differ between those outside and inside the organized markets.

Outside the organized markets, the incentive problems are real but they are more contained. The vertically integrated structure of the industry, full requirements service and reliance on central planning remain, and the procedures and incentive structures of the traditional model provide the principal tools for guiding infrastructure investment. For example, there has been a continuing concern about a low level of transmission investment.[33] As directed by EPAct05, FERC issued Order 679 to promote higher rates of return on investment along with many other incentives under a regulatory model for transmission infrastructure expansion investment that will be included in utility rate base.[34] The entire conception of the transmission expansion mechanism in Order 679 is one of traditional cost of service regulation for vertically integrated utilities. "Merchant projects are market driven while this final rule deals fundamentally with regulated transmission rates. True merchant transmission projects may play an important role in the future of transmission infrastructure development, but incentives related to, for example, [Return On Equity] and cost recovery, do not apply to merchant transmission."[35] The details are familiar from decades of utility regulation, but for vertically integrated utilities these incentive regulation details do not much confront the challenges of operating within markets.

Inside the organized markets covered by the RTOs, the required framework and tools should be different. In order to utilize the advantages of markets, it is fundamental that market participants make decisions about investments in response to incentives they perceive, bearing the risks and reaping the rewards. All these elements are necessary. Without good incentives, there is little reason to believe that market choices will be appropriate. In the face of substantial economic uncertainty, the perceptions of the market participants should govern when possible. After all, if central planners and regulators knew what to do and what investments to make, there would be no need for the market. And if the market participants do not bear the risks as well as reap the rewards, there is little hope that decisions will be good or sustainable.

However, where there are market failures, some investment decisions may require central planning and regulation. For example, large scale transmission investments may exhibit material economies of scale and scope in much the same way as assumed in the past for generation and the whole electricity system. The task for regulators, especially FERC, is

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33 NERC, 2007, p. 18.

34 Federal Energy Regulatory Commission, Docket No. RM06-4-000, Order No. 679, "Promoting Transmission Investment through Pricing Reform," 18 CFR Part 35, Issued July 20, 2006.

35 Order No. 679, ¶262.

to design rules for infrastructure investment that address the market failures and encourage investment in a way that supports rather than undermines the market.

On the biggest issue—open access rules—the current state of market design in organized markets represents a remarkable success. The organized markets are highly regulated through the RTOs and primarily under FERC jurisdiction. However, the form of regulation through the common market design framework is materially different than found outside the organized markets and dramatically different than the traditional model of the vertically integrated monopoly. To a reasonable approximation, control through vertical integration has been replaced by a particular form of horizontal coordination of system operations, markets, and transmission service provided as an integrated piece. Although there still are regulated utilities within organized markets that are integrated in the sense of owning their own generation, these utilities no longer control the critical central piece of transmission access. From the perspective of designing future changes in markets and incentives, therefore, vertical integration with its comforts in absorbing costs and hiding messy details is no longer available. The common market design is both more connected to the reality of how the system works and much more transparent in revealing costs and benefits.

The open access rules and common market framework are necessary for the market to support infrastructure investment, but they are not (yet) sufficient. Hence, FERC faces a continuing agenda of challenges and decisions to modify the rules and incentives to address deficiencies in the organized markets and promote investment, all while avoiding the unintended consequence of undoing the market. On this agenda, the record is troubling, but not all the record has been written. There is still time to act in time.

Consider two examples of infrastructure investment problems that have received a great deal of attention: resource adequacy and economic transmission investment. The resource adequacy questions refer primarily to the pace, type and location of investment in assets needed to meet the baseline projected growth in demand for electricity. In principle, these assets could be anything including energy efficiency, load management, and transmission investment, but in practice the focus as been on new generation assets. The concern with economic investment in transmission is to provide adequate capacity to relieve congestion or support development of new power generation sources, primarily wind power, which must be developed far from the centers of load. In both resource adequacy and economic transmission investment cases, the problems present a challenge that appears not to be met through the current market design. The pressure has been on regulators and central planners to act now to address the long term investment needs.

The ideal regulatory response to these problems of market failure would be to analyze the market design implementation and look first for solutions that reduce or eliminate the market failure. When this is not enough, the second response would be to create a regulatory and central planning intervention that is compatible with the market design. By contrast, the more natural response across the board of market participants, regulators and central planners has been to make a political judgment that fixing the market design is either too hard or won’t work, and to move directly to imposing a regulatory mandate that carries with it the seeds of destruction by creating new market failures and continuing pressure for further regulatory solutions.

Resource Adequacy

The problem of resource adequacy involves many dimensions and details, but the essence of the problem can be captured in a nutshell. Actual implementations of the common market framework have not quite matched the "textbook ideal" described by the IEA review. This is neither surprising nor does it require a counsel of perfection. The goal has always been to create a workable market without expecting to achieve a perfect market. However, in the case of resource adequacy and providing sufficient incentive for investment in new generation, there has been widespread concern that the incentives were not adequate.

The principal evidence cited is the so-called "missing money."[36] For a variety of reasons that include prices caps, operating procedures and conceptual mistakes in translating theory into practice, energy prices in the electricity market were not high enough to support investment in new generating plants. For example, over the nine years 1999-2007, the market monitor for the PJM Interconnection estimates that average energy market revenue under economic dispatch for a combustion turbine peaking unit was $16,401 per MW-year compared to an average fixed cost charge of a new unit of $75,158 per MW-year. Estimates of expected net revenues going forward should be the proper benchmark, but this retrospective look at the actual revenues achieved net of variable costs is sobering and suggests a real problem in the underlying market design. The average net revenues were approximately 22%, 45%, and 63% of the levels needed to justify new investment in a new combustion turbine, gas fired combined cycle or coal plant, respectively. [37] With these revenue gaps, it is surprising that there is as much investment in generation as has been seen.

The many analyses of the missing money problem in different parts of the country all point to essentially the same diagnosis. During times of tight supplies relative to demand—in other words, periods of relative scarcity when a normal competitive market response would be to increase price—the combined effect of the actual rules in RTO markets has been to suppress the real-time (and day-ahead) energy prices.[38] The market failure is clear. Without adequate scarcity pricing it follows that the market incentives would not be sufficient to support investment in generation where and when it is needed.

Unfortunately, another common feature of the analyses of the missing money problem has been a widespread assumption that fixing the scarcity pricing problem would be neither politically feasible nor timely enough to be effective. (Even the terminology is politically charged, but most of the alternatives to "scarcity pricing" are equally unappealing or obscure the point.) As a result, regulators and central planners have sought other mechanisms, principally through generation capacity requirements and

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[36] The characterization as "missing money" comes from Roy Shanker. For example, see Roy J. Shanker, "Comments on Standard Market Design: Resource Adequacy Requirement," Federal Energy Regulatory Commission, Docket RM01-12-000, January 10, 2003.

[37] PJM Market Monitoring Unit, 2007 State of the Market Report, Volume 1: Introduction, Volume 2: Detailed Analysis, March 11, 2008, Tables 3-7 thru 3-9 (Vol. 2) & 1-3 (Vol. 1), respectively.

[38] William W. Hogan, "On An 'Energy Only' Electricity Market Design For Resource Adequacy," Harvard University, September 23, 2005, (www.whogan.com).

associated capacity markets. The experience with these capacity mandates and capacity markets has not been good. The original capacity mandates with short horizons produced disappointing results, especially in New England and PJM. This led to major efforts to reform the associated capacity markets, primarily by extending the horizon out enough years to allow new entrants to respond and get longer-term commitments from the regulators, operating through the RTO, guaranteeing certain capacity revenues separate from the energy market revenues.

The purpose here is not to revisit either the need for or the design of capacity markets. Absent adequate scarcity pricing, the need for something is compelling as indicated by the missing money estimates from PJM. And after much effort, the respective capacity market designs for ISO New England (ISONE) and PJM are about as good as anyone has been able to construct, and current assessments promise much better performance in the future than in the past.[39]

Rather, the purpose here is to emphasize that these capacity markets are not well integrated with the rest of the market design, and they place great emphasis on the ability of central planners and regulators to make decisions in place of markets. The details of the capacity market implementations in PJM and ISONE are different in important ways, which hints that there is some disconnect between the design and the underlying fundamentals. However, these capacity market designs have in common that the RTO is assumed to be able to make good predictions about the level, type and location of capacity needs several years into the future, and that regulators can commit to the payments for these resources while imposing the costs and the associated risks on the ultimate customers. Embedded in these analyses are assumptions about how transmission will be utilized several years in the future. The costs of the resulting capacity payments are largely socialized, over time and to an extent over customer groups. This cost socialization makes it difficult to provide the necessary incentives for integrating demand side efficiency investments, load management options, distributed generation, short-term operating decisions, and so on.

Faced with the substantial uncertainty about the level and location of future capacity needs, not to mention the difficulty of forecasting transmission utilization, capacity markets are markets for a regulated construct – capacity – that look much like regulated procurements in the past that led to the interest in electricity restructuring and the desire to change the locus of decisions and allocation of risks. In the face of great uncertainty and instability, regulators are now much more responsible for making investment decisions, and risks are being transferred away from investors and towards captive customers. To be sure, if regulators and central planners make good decisions, this will all work out. But if we were confident that regulators and central planners could make

[39] John C. Chandley, "PJM's Reliability Pricing Mechanism: Why It's Needed and How It Works," LECG, LLC, March 2008 (available at http://www.pjm.com/documents/downloads/pjms-rpm-j-chandley.pdf). PJM Reliability Pricing Model (RPM) various report at http://www.pjm.com/markets/market-monitor/messages.html. Independent System Operator New England (ISONE), 2007 Annual Markets Report, June 6, 2008 (available at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2007/amr07_final_20080606.pdf).

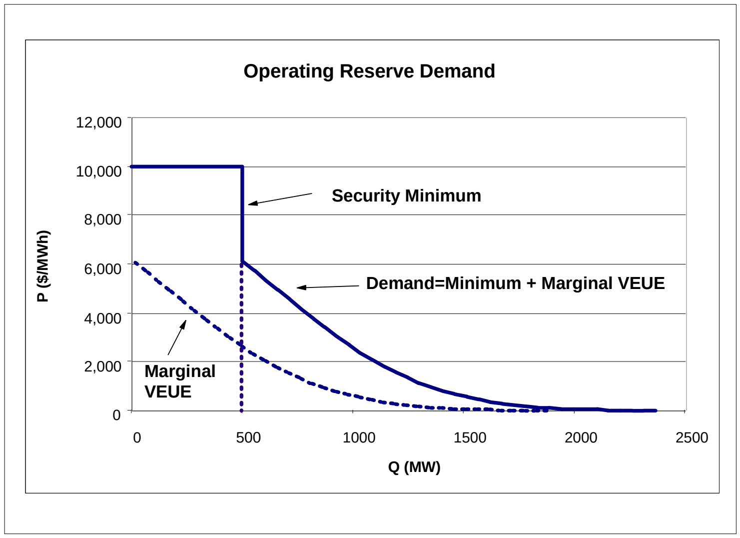
these decisions, we would not need electricity restructuring or the dispersed incentives in markets to prompt innovation and infrastructure investment.

The missing element in this story is reform of scarcity pricing to make the market implementation conform to the design framework. Importantly, there is little dispute that scarcity pricing reform would be desirable and would be compatible with the major commitment to capacity markets. Well designed capacity markets reflect the scarcity pricing in the market, and a change in scarcity pricing rules need not change the structure of the capacity market. But better scarcity pricing would produce three principal benefits. First, better scarcity pricing would shift substantial revenues out of the capacity payments and into the energy market. This would reduce the importance of good choices by central planners and regulators, and shift the risks of being wrong away from customers and towards investors, the type of structure that is compatible with the competitive market. Second, better scarcity pricing would provide better incentives for all the innovations in the market that regulators and central planners do not anticipate and cannot plan. For example, by reducing the socialization of costs, better scarcity pricing would be much more supportive of innovation and investment on the demand side. Third, better scarcity pricing in real-time would provide the last line of defense if by some misfortune the capacity investments promised by the capacity market do not arrive or are not what we need.

Hence, the choice is not between capacity markets and better scarcity pricing. For those that have implemented capacity markets, there is still a need for better scarcity pricing.[40] The argument has been that the priority was to fix the capacity market first, and better scarcity pricing could come later. The opposite priority was probably the better case, but since now is later the next step is clear. In markets that have adopted capacity markets, improved scarcity pricing should be implemented to reinforce the infrastructure investment incentives and to bolster the market mechanisms for dealing with the substantial uncertainty going forward with these investments. In markets that have not implemented capacity markets, but might, better scarcity pricing should be implemented earlier rather than later.

[40] William W. Hogan, "Resource Adequacy Mandates and Scarcity Pricing ('Belts and Suspenders')," comments submitted to the Federal Energy Regulatory Commission, Docket Nos. ER05-1410-000 and EL05-148-000, February 23, 2006, (www.whogan.com).

The exact mechanism for incorporating better scarcity pricing is under discussion in various RTOs and will need support at FERC. Inevitably the pricing rules implicate other features of the electricity market, particularly the need for hedging programs for certain classes of default or core customers. In addition, better scarcity pricing is not likely to be found through trigger mechanisms that remove bid caps and rely on the exercise of market power during periods of scarcity, which would create a headlong collision with both political sustainability and existing mandates for market power mitigation. A workable alternative would be to integrate effective operating reserve demand curves that follow on the model in New York and New England, but with substantial higher prices to reflect the marginal value of expected unserved energy (VEUE) and the implied value of operating reserves as illustrated in the figure.[41]



Transmission Investment

Transmission investment rules present especially difficult problems for market design. There is a widespread concern that there has been too little investment for many years.[42] The NERC projection of transmission circuit mile growth over the next decade is approximately half of the projected growth of peak demand.[43] There has been significant transmission investment in some regions, so it is not clear if the aggregate figures reveal a pressing problem of inadequate economic transmission investment. In response to the mandates of EPAct05, the Department of Energy (DOE) completed its study of transmission congestion and designated two areas, one in the east and another in the west, with significant and sustained congestion but without addressing the question of whether the costs would justify investment.[44] In part, because of both uncertainty in the rules and

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[41] For further details, see William W. Hogan, "On An 'Energy Only' Electricity Market Design For Resource Adequacy," 2005.

[42] Joseph T. Kelliher, Chairman, Federal Energy Regulatory Commission, Testimony Before the Committee on Energy and Natural Resources, United States Senate, July 31, 2008, p. 13.

[43] NERC, 2007.

[44] Department of Energy, "Docket No. 2007–OE–01, Mid-Atlantic Area National Interest Electric Transmission Corridor; Docket No. 2007–OE–02, Southwest Area National Interest Electric Transmission Corridor, National Electric Transmission Congestion Report", <u>Federal Register,</u> Vol. 72, No. 193, Friday, October 5, 2007, PP. 56992-57028.

economic uncertainty about the need for transmission, it is not an easy matter to identify economic transmission investments that are not being made.

Of course, there are many obstacles to building new transmission. Part of the motivation for the EPAct05 provisions directing DOE to identify National Interest Transmission Corridors stemmed from siting concerns and possible failures of local and state agencies in recognize the broader regional benefits of improved transmission and wider interstate commerce. Getting siting and related environmental approvals for major transmission investments is a complicated and long process that many would like to reform. However, for our present purposes, these generic problems for transmission investment are neither new nor specific to the challenges of integrating markets and regulation.

Although market-driven merchant transmission investment is recognized as both possible in principle and occurring in practice, there is a familiar argument about a fundamental market failure in supporting transmission expansion. In particular, markets price congestion of the type identified by the DOE study. Economic investments in transmission are designed to relieve some or all of the congestion. When transmission investment is small relative to the larger market, the impact on congestion prices will be small and the property rights created through FTRs and related benefits might be sufficient to justify the investment. However, if the investment is large enough to have a material effect on congestion prices, there could be a significant difference between the ex ante congestion prices that point to the need for investment and the ex post congestion prices that would define the value of the FTRs. This is a classic economy of scale argument, where monopoly provision with regulated cost recovery has a natural application. This is the argument that markets alone may not be able to support all transmission investment.

It is easy to construct hypothetical examples where the economies of scale would apply and would be a barrier to efficient transmission investment. In this case there is support for the regulated investment model with the associated decision rules and cost allocations. However, it would be a mistake to assume that this condition applies to all or even most situations where transmission investment would be economic. Hence, the challenge is to design the transmission investment rules in the organized markets to support a hybrid system with both regulated investment where central planners make the decisions and regulators mandate cost recovery, and merchant investment where market participants make the decisions, reap the rewards and bear the costs.

Some of the requirements of a hybrid system seem to be clear. Property rights must be defined for the transmission investor. Cost allocation must follow the beneficiary pays principle. Decisions should defer to market choices when there is no compelling evidence of a market failure. There must be a mechanism to separate cases where regulated investments mandates would be appropriate from those where market choices should prevail.

The need for well defined property rights is a fundamental requirement for markets and decentralized choices. If investors cannot obtain sufficient benefits from the investment, then merchant investment would be impossible to support. In the organized markets of the RTOs, the principal tool for defining and providing a workable set of property rights is award of the FTRs that would be created as a result of transmission expansions. While not perfect or complete, FTRs seem to be necessary, and in many cases for relatively small increments could be sufficient, to support transmission investment. A large number of small investments can have a large effect. As a result of past FERC decisions, long-term incremental FTRs are part of the design in most of the existing RTOs. This is not a particularly controversial idea.

Cost allocation according to the principle that the beneficiary of the investment pays the cost is not controversial in the abstract but is honored in the breach in practice. It is not always easy to get agreement on the identity of beneficiaries and the magnitude of the relevant benefits. Hence, while recognizing the principle, it is sometimes recommended that costs be socialized and that the allocations will balance out over time and across portfolios of projects.[45] Innocuous as this argument may seem, it strikes at the heart of a framework that would integrate well with market decisions. This argument conflates the resulting average incidence of cost responsibility and the marginal incentive effects for investment. Under the beneficiary pays principle, the average incidence across many investments might be about the same as for a socialized cost allocation, but the incentive for each investment in transmission or its alternatives would be quite different under a beneficiary pays or a socialized allocation.

Cots-benefit studies are or should be a regular part of transmission expansion evaluations.[46] A fundamental characteristic of transmission expansion is expected change in the patterns of power flow and the composition of supply, demand and prices. For example, see the PJM analysis for the "502 Junction-Loudon Line" where the range of impacts across nineteen zones evaluated was from -$7.17/MWh to +$8.77/MWh.[47] If a cost-benefit study suggests that there would be net benefits, it will of necessity provide some estimate of the distribution of benefits. If that result shows the benefits are widely dispersed, it would follow from the beneficiary pays principle that cost allocation should be widely dispersed. However, this possibility should not be assumed or taken as the default assumption in favor of cost socialization. A default presumption in favor of cost socialization would undermine incentives, including the incentive to perform or evaluate the cost benefit analysis.

Socialized cost allocation, which by definition means that regulators mandate the payment and some market participants are subsidizing others, fundamentally undermines the incentives of market investment for both transmission and its alternatives, which includes everything. It is hard to conceive of a hybrid system that widely socializes costs and still supports market-driven investments. Initially it may seem like a small and

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[45] The Blue Ribbon Panel on Cost Allocation, "A National Perspective On Allocating the Costs of New Transmission Investment: Practice and Principles," September 2007, p. 7. (available at http://www.hks.harvard.edu/hepg/Papers/Rapp_5-07_v4.pdf).

[46] For example, see PJM Compliance filing on the economic transmission planning process, FERC, Docket No. FR006-1474-003, March 21, 2007. PJM "Business Rules for Economic Planning Process," September 2008, (www.pjm.com).

[47] PJM, "Market Efficiency Analysis Progress Report," PJM Planning Committee, Transmission Expansion Advisory Committee, April 18, 2007, http://www.pjm.com/committees/teac/downloads/20070418-item-10-market-efficiency-analysis-prog-rep.pdf .)

isolated problem restricted to certain complicated transmission investments, but this is likely to be a delusion. The forces are already in motion to extend the socialization principle to other types of infrastructure investment. For example, the DOE congestion study explicitly excluded consideration of alternatives to transmission, arguing that EPAct05 had passed that hot potato to FERC where approval of transmission investments would have to consider alternatives to transmission investment, both in the form of generation and demand side investments, and "… FERC has committed to considering non-transmission alternatives, as appropriate, during its permit application review process."[48]

Cost socialization is not necessary for transmission investment. The beneficiary pays principle is compatible with transmission investment. For example, the Wyoming-Colorado Intertie transmission project would access distant wind resources from Wyoming and sell the energy in Colorado. The project finance model calls for the wind generators, the beneficiaries, to pay through advance commitment to purchase capacity on the line. "As part of the Open Season process, the project sponsors had offered up to 850 megawatts of transmission capacity in a public auction. This has resulted in 585 megawatts of capacity purchase commitments from credit-worthy parties. … The project sponsors are optimistic that the remaining 265 megawatts of capacity will be sold. The project sponsors expect to complete the siting, permitting, and construction of the line and begin operation by mid-2013."[49] This is a large project where beneficiaries are expected to pay.

However, on this important cost allocation principle, FERC has shown no discernible interest in sticking to a principle. The FERC-approved cost allocation for ISONE treats one hundred percent cost socialization as the default approach. Recent testimony describes one third of costs socialized in the Southwest Power Pool (SPP), twenty percent socialization of costs for the Midwest Independent System Operator (MISO), zero per cent socialization for low voltage and one hundred percent socialization for high voltage investments in PJM.[50] The FERC approved framework of the California ISO (CAISO) for "locationally constrained resource interconnection facilities," primarily for new wind generation, socializes the risk that renewable resource investments will not be adequate to pick up the cost of the transmission investment.[51] From this collection of decisions, it is not clear what the underlying recipe is, other than a recipe for trouble by driving more and more investment decisions and subsidy requests onto the regulator's agenda. Adherence to the principle of beneficiary pays seems essential for any sustainable hybrid system of transmission investment.

The need for a hybrid system that can defer to market judgments when there is no market failure arises from the great uncertainty that surrounds all these investment choices. This

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48 Department of Energy, "National Electric Transmission Congestion Report," 2007, P. 56994.

49 Western Area Power Administration, "Open Season a Success for Wyoming-Colorado Intertie," Press Release, August 26, 2008. (www.wapa.gov/newsroom/pdf/WCIOpenSeasonOutcome82608.pdf).

50 Joseph T. Kelliher, Chairman, Federal Energy Regulatory Commission, Testimony Before the Committee on Energy and Natural Resources, United States Senate, July 31, 2008, pp. 12-13.

51 CAISO, http://www.caiso.com/1816/1816d22953ec0.html .

uncertainty guarantees that there will be important cases where central planners and market participants have different views about the future risks and rewards. The presumed advantage of the market-based investments is that the allocation of risks is more closely linked to the decision to invest. When markets and central planners disagree, a hybrid system would require a high threshold before concluding that planners are correct and overruling market choices. And the threshold should be linked to identifying a market failure that is a barrier to entry, not just that the market failed to do what the planner preferred.

This deference to the market in a hybrid system would be closely related to the need for some mechanism for distinguishing between those infrastructure investments that would be eligible for regulated treatment and those that should be left to the market. Otherwise, everything will be a special case and FERC will have no principled basis for deferring to the market. A particularly attractive approach follows from the early experience in Argentina and is now embodied in the transmission expansion framework proposed by the New York ISO (NYISO).

> "The proposed cost allocation mechanism is based on a "beneficiaries pay" approach, consistent with the Commission's longstanding cost causation principles. … Beneficiaries will be those entities that economically benefit from the project, and the cost allocation among them will be based upon their relative economic benefit. … The proposed cost allocation mechanism will apply only if a super-majority of a project's beneficiaries agree that an economic project should proceed. The super-majority required to proceed equals 80 percent of the weighted vote of the beneficiaries associated with the project that are present at the time of the vote."[52]

This simple approach supports a hybrid scheme. Adherence to the beneficiary pays principle avoids the problems of cost socialization. The voting procedure allows for regulated transmission projects to proceed when most but not all the beneficiaries agree, while deferring to the judgment of the market when the supermajority cannot be obtained. When a small minority of beneficiaries objects, the regulatory mandate is imposed, to meet the problem of the presumed market failure. The NYISO system also embeds a principled answer that avoids the need to socialize the costs of most alternative investments in generation and load where the beneficiaries are usually easy to identify. If applied to transmission investment cases of a scale and scope that suggests the possibility of a market failure, there would be available a principled answer to the requests to extend the regulatory investment support to alternatives like generation and demand side investments which are typically small and have concentrated beneficiaries.

The NYISO framework for regulated investments and models like the Wyoming-Colorado auction could be compatible parts of a hybrid system for transmission investment. In addition, reform of scarcity pricing would tend to increase the market

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[52] New York Independent System Operator, Inc Docket No. OA08-13-000, "Order No. 890 Transmission Planning Compliance Filing," Cover Letter Submitted to Federal Energy Regulatory Commission, December 7, 2007, pp. 14-15.

price of transmission congestion, reinforcing the market incentives and beneficiary pays principle for transmission investment.

Summary

A key challenge for electricity market design and regulation is to support efficient investment in infrastructure. Outside the organized markets, FERC faces the continuing challenge of implementing and enforcing the principles of open access, which would require a change in institutions and rules similar to the organized markets covered by RTOs. Inside the organized markets, the continuing problem is to design rules and regulatory policies that support competitive wholesale electricity markets. A key requirement is to relate any proposed solution to the larger framework and to ask for alternatives that better support or are complementary to the market design. Many seemingly innocuous decisions appear isolated and limited, but on closer inspection are fundamentally incompatible with and undermine the larger framework. Improved scarcity pricing and a hybrid framework for transmission investment are examples of workable solutions that seem necessary to meet the needs for a long-term approach to infrastructure investment. These are instances of the ideal regulatory response to problems of market defects and market failure. First, analyze the market design implementation and look first for solutions that reduce or eliminate the market failure. Second, when this is not enough, create a regulatory and central planning intervention that is compatible with the market design. The alternative is to frame every problem in its own terms and design ad hoc regulatory fixes that accumulate to undermine market incentives. A workable regulatory and market framework is an essential tool for anticipating unintended consequences and acting in time.

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