MEASURING THE BENEFITS AND COSTS OF REGIONAL ELECTRIC GRID INTEGRATION

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I. INTRODUCTION

Electric industry restructuring in its modern form has been underway for over a decade in the United States. The major new institutional arrangement under United States restructuring is the formation of the Independent System Operator (ISO) or the Regional Transmission Operator (RTO). The RTO is an independent not-for-profit organization (independent in the sense that it owns no assets and does not take a position in the wholesale power market) that manages the joint transmission assets of a number of transmission-owning electric utilities. In many places, RTOs also run centralized regional spot markets for electric energy, ancillary services, and offer financial contracts for hedging congestion risk.[1] Other than the move from a market based physical transmission rights to one based on financial transmission rights, one major difference between RTO markets and their predecessors is the aggregation of generation resources for economic dispatch. Prior to the introduction of RTO markets, generation resources were either dispatched centrally at the level of the individual utility or power pool. With the introduction of RTO markets, the generation resources over a number of utility control areas are cost-optimized and dispatched jointly.[2]

It is striking that, even after ten years of experience, neither industry nor academia has produced a definitive study of the costs and benefits of RTO markets and regional grid integration. Broadly speaking, analyses by RTOs and industry consultants trumpet benefits to consumers in the billions of dollars, while academics have generally come to the opposite conclusion.[3] Part of the controversy stems from the fact that certain studies claim large benefits from regional grid integration based on one set of factors (or performance metrics) while others claim large costs from a different set of factors. This paper does not attempt to provide the definitive study, but rather seeks to lay out a reasonably complete set of factors or performance metrics that ought to be considered in any serious analysis of the costs and benefits of RTO markets or operations. In this sense, the paper hopes to right the path of the debate over electricity restructuring by providing a foundation for future cost-benefit studies and discussions. Restructuring's major failures should be blamed not on opportunistic behavior by any party or group of parties, but rather on the failure of regulators, policymakers, and market designers to develop precise policy goals and complete performance metrics (and also the failure to verify that a given market design would meet the policy goals). The focus of this paper is

1. There are some differences between ISOs and RTOs in their governance structure and congestion-management protocols. Operationally, ISOs and RTOs look very similar. For consistency, we will use the RTO terminology somewhat ambiguously throughout this paper to refer to an institutional arrangement where the transmission assets of several utilities are jointly and independently managed, coupled with a regional spot market for electric energy.

2. In some cases, such as the RTOs in New York and New England, the RTO footprint is nearly identical to the pre-existing power pool. RTO territories in the Mid-Atlantic and Midwest, on the other hand, are far larger than the utility control areas or power pools they replaced.

3. The various studies will be discussed further in Section 4.

limited to the shift towards regional grid integration through RTO market and operations. It does not discuss other institutional changes associated with restructuring, such as the movement away from cost-based rates or the possibility of increased industry consolidation through (for example) the repeal of the Public Utility Holding Company Act.

Regional integration and the RTO market structures have had benefits, largely in the form of increasing the operating efficiency of base-load plants in the Eastern Interconnection (fueled largely by coal and nuclear fission). Whether the increased market liquidity and operating efficiency has brought benefits to ultimate consumers is a controversial subject that has just started to get the attention of academics in the past couple of years. Section 2 provides some background on the process of electric industry restructuring and the introduction of regional transmission coordination and power markets. Section 3 provides a conceptual discussion of the loss of utility-level dispatch as a policy tool and draws some parallels with the economic theory of currency union. Section 4 discusses how the costs and benefits of regional electric grid integration have been measured and evaluated in the existing literature. The focus of Section 4 is on the effects of regional integration on generator operating efficiency, wholesale market efficiency, and retail price effects seen by end-use customers. There have been a number of direct and indirect costs associated with regional grid integration that have largely been left untouched by the existing literature; several of these are discussed in Section 5. Each of these issues could likely be the subject of its own study; this paper provides some preliminary evidence. Section 6 provides a summary of the metrics discussed in this paper. Section 7 offers some concluding thoughts.

II. UNITED STATES ELECTRIC INDUSTRY RESTRUCTURING AND THE EVOLUTION OF REGIONAL COORDINATION

Restructuring of the electric utility industry in the United States began as a response to the oil price shocks of the 1970s. At the time, roughly twenty percent of the electric generation in the United States was from oil-fired power plants.[4] The Public Utilities Regulatory Policy Act (PURPA) of 1978 was aimed at encouraging the use of generation fuels other than oil. PURPA also allowed electric power to be generated by independent (non-utility) power producers (IPPs); these generators produced power under long-term contracts with electric utilities, who then resold the power to ultimate consumers. PURPA contracts, combined with the rise in oil prices, were successful in reducing the amount of electricity generated with oil. However, many of the contracts fetched high prices, which pushed up the cost to consumers even further.[5]

4. GRANGER MORGAN, JAY APT, & LESTER LAVE, PEW CTR. ON GLOBAL CLIMATE CHANGE, THE U.S. ELEC. POWER SECTOR AND CLIMATE CHANGE MITIGATION (2005), *available at* http://www.pewclimate.org.

5. Generating units that qualified under PURPA were given very favorable rate treatment; the contracts were signed at "avoided cost," with the exact determination left up to individual states. California and Massachusetts had avoided-cost provisions that were very favorable to the generators.

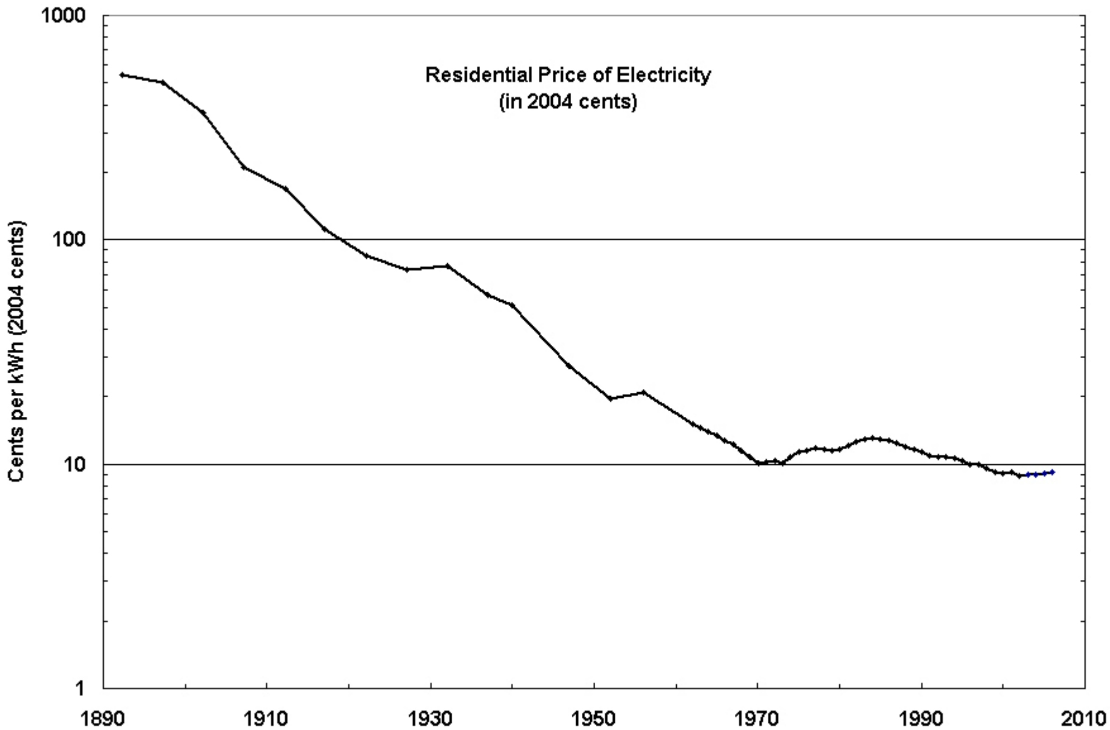

Figure 1: Inflation-adjusted Residential Price of Electricity. Source: GRANGER MORGAN, JAY APT, & LESTER LAVE, PEW CTR. ON GLOBAL CLIMATE CHANGE, THE U.S. ELECTRIC POWER SECTOR AND CLIMATE CHANGE MITIGATION (2005).

During the 1970s, the price of electricity rose for the first time since the early 1900s, as shown in Figure 1. A short time thereafter, the rate of electricity demand growth slowed dramatically, going from exponential growth (a constant percentage demand growth averaging six percent per year) to linear growth, as shown in Figure 2. In addition to high-cost PURPA contracts, many utilities were also saddled with high cost investments (particularly for nuclear power plants) made under the assumption that demand would continue to grow at a constant percentage rate. Since state regulators and public utility commissioners had approved these investments, customer ire was directed towards the regulators as well as the utilities.

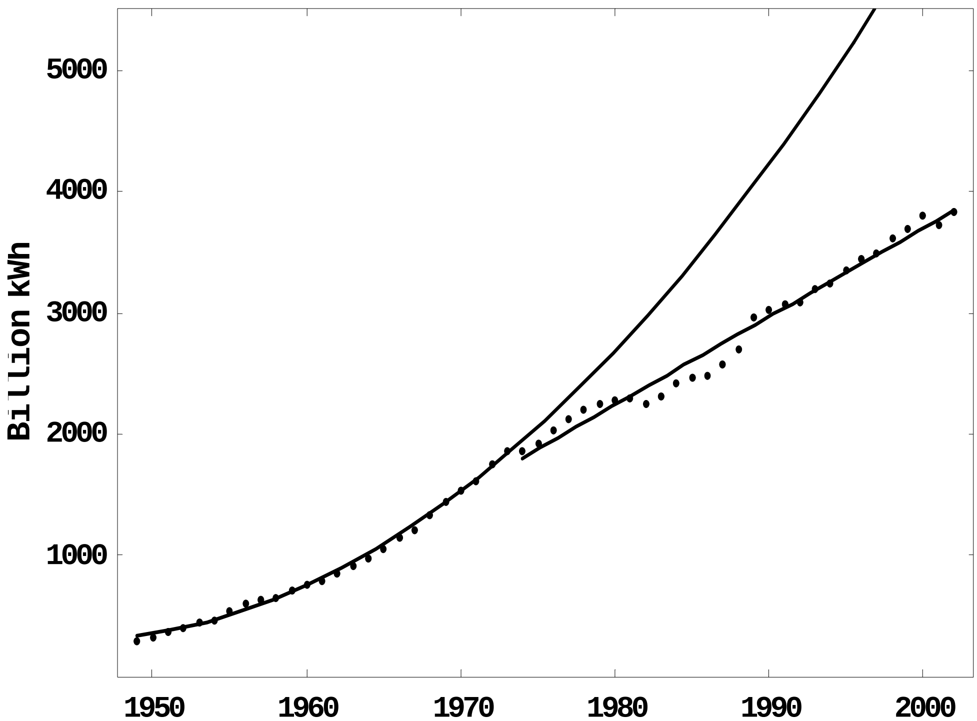

Figure 2: United States Electricity Sales, All Sectors, 1950 – 2002. The dotted line represents actual sales, while the solid lines represent the exponential trend and the shift to linear growth beginning in 1973. Source: GRANGER MORGAN, JAY APT, & LESTER LAVE, PEW CTR ON GLOBAL CLIMATE CHANGE, THE U.S. ELECTRIC POWER SECTOR AND CLIMATE CHANGE MITIGATION (2005).

Meanwhile, a number of other network industries had undergone a process of restructuring and price deregulation, with generally successful results. For example, natural gas and airlines were both deregulated in 1978, with railroads and trucking deregulated in 1980. Introducing competition to these industries is thought to have yielded thirty percent to seventy-five percent improvements in consumer welfare,[6] largely through the harmonization of prices throughout the network.[7]

Economists had long believed that the production, transportation, and delivery of electricity had a different cost structure than other industries, due to the capital-intensive nature of the electric grid. The early days of the electric utility industry were, in fact, marked by a rather chaotic competition, as firms laid multiple sets of transmission and distribution wires in the same location,

6. Clifford Winston, *U.S. Industry Adjustment to Economic Deregulation*, 12 JOURNAL OF ECONOMIC PERSPECTIVES 89 (1998) [hereinafter Winston]. The metric used for consumer welfare is the consumer surplus, which represents welfare improvements through efficiency gains and increased competition, rather than through prices. There is a subtle difference between lowering costs (which in turn should lower prices through competition) and lowering prices (which could represent competition or the actions of regulators). As discussed below, many of the consumer benefits of restructuring in electricity have come through lower prices in the form of rate intervention by regulators.

7. Analysis of the natural gas market provides a nice illustration; *see* Arthur de Vany & W. David Walls, *Pipeline Access and Market Integration in the Natural Gas Industry: Evidence from Cointegration Tests*, 14 ENERGY JOURNAL 4 (1993).

competing for customers.[8] Further, the efficiency of electric generating units seemed to improve with size.[9] The existence of economies of scale in all three business areas of the utility industry (generation, transmission, and distribution) led economists to believe that the regulated monopoly structure was the most efficient for the industry.[10]

Operation of the transmission and distribution grid is still likely to be most efficient under a regulated monopoly. However, economists have begun to question the extent of scale economies in generation.[11] Analysis by Paul Joskow and Richard Schmalensee suggested that a competitive market for electric energy was possible and would likely improve operating efficiency.[12] Subsequent microeconometric analysis has suggested the efficiency gains could be in the neighborhood of seven percent to thirteen percent.[13] In 1987, the FERC approved a set of electricity trading protocols for the Western Systems Power Pool, thus sanctioning the bilateral market that had existed in the West for decades. The Energy Policy Act of 1992 (EPAct 1992) passed by the United States Congress allowed marketers (entities that did not serve load or own generation) to enter the market, and trading began in earnest.[14]

Simply opening up competition at the wholesale level by expanding the field of eligible market participants was not successful at bringing down electricity prices. One reason is that transmission owners had incentives to restrict access to their portions of the network.[15] Since transmission must facilitate competition, discriminatory and nontransparent access protocols had the effect of potentially stifling competition. Another reason is that EPAct 1992 left a disconnect between the wholesale and retail markets. Subject to FERC approval, wholesale prices determination was left to the market, while retail rates remained fixed under the authority of state public utility commissions.

Policies to encourage wholesale market activity have largely taken place at the federal and regional level, while reform in the retail sector has largely been left to the individual states. These reforms have largely come through policies

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8. S.A. Van Vactor, Flipping the Switch: The Transformation of Energy Markets (Feb. 12, 2004) (Ph.D. dissertation, Univ. of Cambridge) [hereinafter Van Vactor].

9. RICHARD HIRSCH, POWER LOSS (MIT Books 1999); GRANGER MORGAN, JAY APT, & LESTER LAVE, PEW CTR. ON GLOBAL CLIMATE CHANGE, THE U.S. ELEC. POWER SECTOR AND CLIMATE CHANGE MITIGATION (2005), *available at* http://www.pewclimate.org.

10. Regulation of electric utilities did not come about on the advice of economists. Rather, the largest and most successful firms of the time realized the scale efficiencies that were involved and asked for regulation, rather than face "ruinous competition." *See* S.A. Van Vactor, Flipping the Switch: The Transformation of Energy Markets (Feb. 12, 2004) (Ph.D. dissertation, Univ. of Cambridge); FORREST MCDONALD, INSULL (University of Chicago Press 1962).

11. Lauritis R. Christensen & William H. Greene, *Economies of Scale in U.S. Elec. Power Generation*, 84 JOURNAL OF POLITICAL ECONOMY 655 (1976); J. JOHNSON, STATISTICAL COST ANALYSIS (Seymour E. Harris ed., McGraw-Hill 1960).

12. PAUL L. JOSKOW & RICHARD SCHMALENSEE, MARKETS FOR POWER: AN ANALYSIS OF ELEC. UTIL. DEREGULATION (MIT Press 1983).

13. Lauritis R. Christensen & William H. Greene, *Economies of Scale in U.S. Electric Power Generation*, 84 JOURNAL OF POLITICAL ECONOMY 655 (1976); Thomas Klitgaard & Rekha Reddy, *Lowering Electricity Prices Through Deregulation*, CURRENT ISSUES IN ECON. AND FINANCE, Dec. 2000.

14. Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (codified in scattered sections of 15, 16, 38, and 42 U.S.C.).

15. The physics of AC power flow make it impossible to literally restrict electrons from flowing over certain lines. Discriminatory access came most often through the use of transmission loading relief (TLR) actions, which allowed a transmission owner to effectively restrict access to the network by disallowing individual transactions. TLR protocols were originally designed to handle contingencies or congestion on the grid, but were sometimes used to favor certain generating units over others in the competitive market.

aimed at organizational restructuring of the traditional vertically-integrated utility, and those aimed at encouraging retail competition. Thus, restructuring in the United States has represented a patchwork of state and federal policies. A summary of the reform process in the United States would break restructuring down into the following components:

- Vertical dis-integration of the generation, transmission, and distribution utility businesses. In some states, such as California, this dis-integration required outright divestiture. Other states, such as Pennsylvania, did not explicitly require divestiture but did restrict the amount of communication that could exist between the utility business units;
- Introduction of retail competition at the generation level, where individual consumers could choose the company that would sell them electric energy, at rates increasingly based on market prices rather than regulated costs. Distribution and delivery remained regulated in the hands of the incumbent utility;
- Recovery of stranded costs, i.e., investments made by utilities in the regulated era whose costs would put them at a competitive disadvantage under competition. The largest stranded-cost allowances have generally been for nuclear power plants;
- The opening of centralized spot markets for electric energy (and in some cases ancillary services such as capacity and reserves);
- Management of the electric grid on a regional scale by an independent entity, rather than the transmission owner managing its local portion of the network.

This paper is largely concerned with the last two items. The FERC has played an instrumental role in developing policies to promote spot markets for energy and the formation of RTO, while the particulars of the first three have largely been left to the states. Four FERC actions in particular have influenced the path that restructuring has taken in the United States. First, in 1996, the FERC issued Order 888[16] and Order 889.[17] Order 888 required every transmission-owning utility in FERC's jurisdiction to offer nondiscriminatory access to its transmission system, and to file an open access tariff with the FERC. Order 888 recognized the critical role played by the transmission network in facilitating competition among generators. Order 889 was essentially an extension of Order 888 that required some level of market transparency at the level of the transmission network. It required transmission owners to maintain a public online database, known as the Open Access Same-Time Information System (OASIS). Each transmission owner's OASIS site was supposed to contain data, updated in real-time, on the state of the transmission network and available transmission capacity.

Orders 888 and 889 were aimed at encouraging the fledgling decentralized bilateral markets in the United States. FERC Order 2000[18] and the Standard

16. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities; Notice of Technical Conference Concerning Independent System Operators and Reform of Power Pools Under the Federal Power Act*, F.E.R.C. STATS. & REGS. ¶ 35,030 (1996), 61 Fed. Reg. 705 (1996) (to be codified at C.F.R. pts. 18, 35).

17. Order No. 889, *Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct*, F.E.R.C. STATS. & REGS. ¶ 31,035 (1996), 61 Fed. Reg. 21,737 (1996) (to be codified at C.F.R. pts. 18, 37).

18. Order No. 2000, *Regional Transmission Organizations*, F.E.R.C. STATS. & REGS. ¶ 35,307 (2000), 65 Fed. Reg. 45,854 (2000) (to be codified at C.F.R. pts. 18, 35).

Market Design (SMD) Notice of Proposed Rulemaking (NOPR)[19] attempted to get the entire transmission network under the FERC's jurisdiction to operate under a similar set of protocols. Order 2000 mandated that every transmission owner join or form a FERC-approved RTO. Under SMD, every FERC-approved RTO would operate and run a spot market for electric energy similar to the market design adopted by the Pennsylvania-New Jersey-Maryland Interconnection (PJM).[20] Broadly, the FERC's preferred market design would have the following features that represented a departure from accepted practice in many areas of the United States.

The RTO would centrally dispatch generation within its footprint according to an algorithm known as security-constrained economic dispatch (SCED). The SCED algorithm minimizes the total cost of generation to serve a given amount of load, subject to operating and reliability constraints in the network. Prior to restructuring, individual load-serving utilities would fill demand through a combination of self-scheduled generation and bilateral contracts.

The RTO would hold a centralized spot market for electric energy (and perhaps ancillary services such as spinning and non-spinning reserves, and black-start capability). The bids from this spot market would determine the dispatch order for generators. Traditionally, the wholesale power market had been conducted entirely on an over-the-counter bilateral basis, with individual transactions communicated to transmission operators.

Transmission congestion would be managed financially rather than physically. Prior to restructuring, a bilateral contract for energy would need to be accompanied by the purchase of physical transmission rights. In the event of congestion on the transmission network, the transmission owner would ration access to the network or undo transactions with low levels of associated transmission rights, through a set of protocols known as Transmission Loading Relief (TLR). Under the FERC's SMD, the centralized dispatch would produce a set of locational marginal prices (LMPs), which reflected the social cost of getting energy to a particular point in the system. Transportation costs and transmission congestion would be signaled to the market through differences in LMPs. Nondiscriminatory access to the transmission network would preclude the existence of physical transmission rights, but market participants could hedge exposure to congestion charges using a variety of financial instruments known generically as financial transmission rights (FTRs).

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19. Notice of Proposed Rulemaking, *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, 112 F.E.R.C. ¶ 61,073 (2005) [hereinafter NOPR].

20. The market design was influenced heavily by the spot pricing analysis of FRED SCHWEPPE, SPOT PRICING OF ELECTRICITY (Thomas Lipo ed., Kluwer Academic Publishers 1987) and the contract network analysis of William Hogan, *Contract Networks for Electric Power Transmission*, 4 JOURNAL OF REGULATORY ECONOMICS 211 (1992) [hereinafter W. Hogan].

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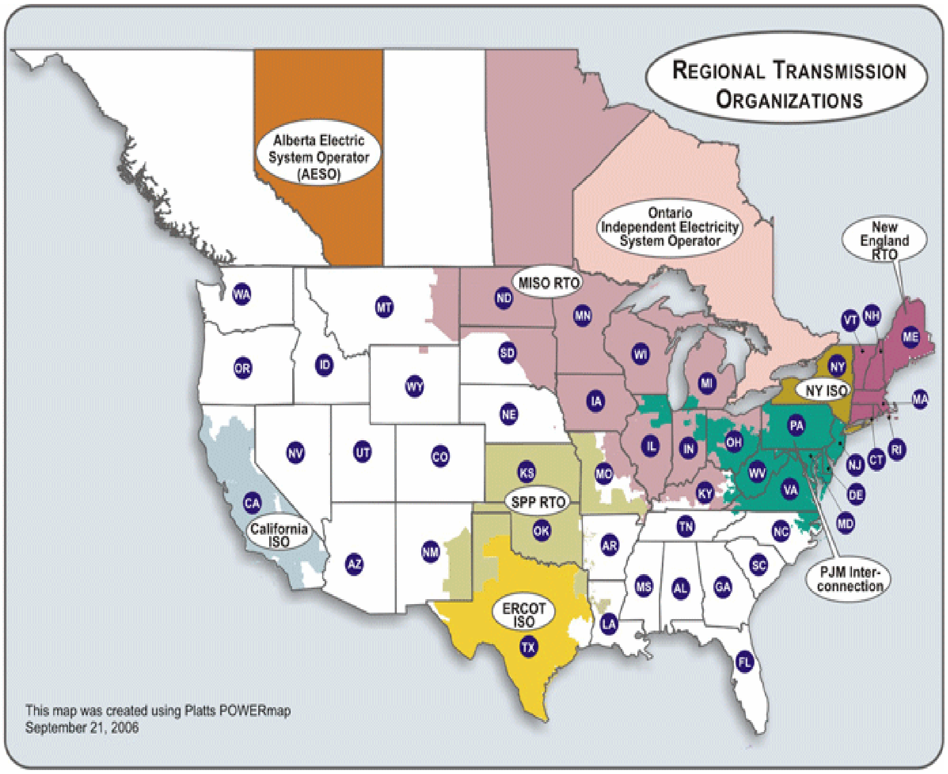

Figure 3. Existing regional transmission organizations. Source: The FERC.

Transmission owners have generally accepted the open-access principles underlying Order 888 and Order 889. Order 2000 and the SMD proposal have been met with much more mixed results; the controversy over SMD in particular was so great that the FERC was forced to abandon the proposal in 2005.[21] Nevertheless, the basic market model in SMD is now used by almost every centralized power market in the United States. The Northeastern United States was quick to adopt both the RTO model and the market model enumerated in SMD. PJM began its market operations in April 1998; the New York ISO (NYISO) and ISO New England (ISO-NE) opened similar markets late in 1999. More recently, PJM has undergone an expansion with its footprint covering all or part of a dozen states plus the District of Columbia. The Midwest ISO (MISO), which was established shortly after the opening of the PJM spot market, started running its own spot market, which operates similarly to PJM, in 2005. The Southwest Power Pool (SPP) operates as a FERC-approved RTO, but without operating a centralized spot market for electric energy. California's market redesign, recently approved by the FERC, borrows heavily from the PJM market model.[22] Figure 3 shows the current footprints of FERC-approved RTOs and other ISOs.[23]

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21. NOPR, *supra* note 19.

22. *California Independent System Operator Corp.*, 116 FERC ¶ 61,274 at P 6 (2006).

23. ISOs operate very similarly to RTOs, but without explicit FERC approval. California and Texas currently run ISOs that have not been approved by the FERC. California is in the process of gaining FERC approval for its open access transmission tariff. The Texas market operates entirely within the State's borders, and thus is not subject to FERC jurisdiction.

III. IS REGIONAL ELECTRIC GRID INTEGRATION GOOD OR BAD? CONCEPTUAL LESSONS FROM THE ECONOMICS OF OPTIMAL CURRENCY AREAS

The formation of RTOs represents an operation and market integration of the transmission systems and generation resources formerly controlled by individual vertically-integrated utilities. Transmission access and dispatch protocols thus reflect policy tools that the utility hands over to the RTO. Given the highly interconnected nature of the power grid, a reasonable *a priori* policy suggestion would be to organize integrated RTOs to mirror physical segments of the transmission grid. The United States power grid is made up of three distinct sub-regions: the Eastern and Western Interconnects (roughly demarcated by the Rocky Mountains), and Texas. Within each sub-region, the electric network is highly interconnected and interdependent. Little transfer capability exists between these three sub-regions (and is limited to back-to-back DC connections, which are easier for operators to control than the larger AC power grid). Setting up one RTO for each of the United States Interconnections would therefore seem logical. But it is not necessarily so.

The problem of whether individual systems or markets should be integrated has parallels in the movement towards the European Monetary Union in the 1990s. European markets are highly integrated, but are made up of a large and heterogeneous group of countries, each of which used to issue its own currency and pursue its own monetary and fiscal policies. The number of different policies, particularly monetary policies, could act as a barrier to cross-border trade by increasing transactions costs and exchange-rate risks between the currencies of individual countries. Removal of these barriers to trade would therefore be beneficial.

Robert Mundell first pointed out there may be costs associated with the loss of currency control as a policy tool.[24] In the world of neoclassical macroeconomics, monetary policy (particularly revaluation of national currencies) can be a useful tool in helping countries adjust to macroeconomic market shocks. As an illustration, we use Mundell's example of an increase in demand. Suppose that there are two countries, A and B, and suppose that consumer demand suddenly shifts from products made in Country A to products made in Country B. Thus, output and employment both increase in Country B and decrease in Country A. In all likelihood, Country A will start running a current-account deficit (the current account is equal to domestic production less domestic spending) and Country B will have a current-account surplus. Country B may also experience inflationary pressures. The most obvious policy response to restore equilibrium in both markets is for the two countries to revalue their currencies; the value of Country B's currency will have to increase relative to Country A's currency, making products from Country B more expensive. If both countries have the same currency, then this policy tool is lost.

Another possible cost of monetary union concerns the relative preference of individual countries for inflation and unemployment. Classical macroeconomics suggests an inverse relationship between inflation and unemployment known as the Phillips Curve.[25] Different countries have different Phillips Curve

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24. Robert A. Mundell, *A Theory of Optimal Currency Areas*, 51 AMERICAN ECONOMIC REVIEW 657 (1961).

25. Modern macroeconomics has cast substantial doubt on the robustness of the Phillips curve, particularly when expectations of future inflation are taken into account. A nice discussion in the context of

relationships, but they are linked through international trade and currency markets. If Country A and Country B choose to be on different portions of their respective Phillips Curves (that is, if they choose different inflation-unemployment combinations), then the exchange rate acts to maintain equilibrium in the international currency market. Under monetary union, the exchange rate between Countries A and B becomes zero, which may make each country's choice of inflation and unemployment targets unsustainable.

There are thus benefits to giving up currency control as a policy tool in the reduction of cross-border transactions costs and exchange-rate risks. The costs involve the potential loss of macroeconomic policy control. Losing currency valuation as a policy tool is significant if no other policy tool exists to accomplish an identical policy goal. Focusing on the first cost of monetary union (shifts in demand), there are two possible factors which could largely mitigate the costs of monetary union. The first is wage flexibility. If wages in the two countries are allowed to adjust reasonably freely, then wages will increase in Country B along with demand for its products. Similarly, wages will fall in Country A along with the employment level. This has the potential to restore equilibrium in both countries. The second factor is labor mobility; the effects are similar to wage flexibility. If labor is highly mobile across international boundaries, then the increase in production in Country B will attract workers from Country A, and equilibrium will again be restored.

Country A and Country B might thus be better off joining a currency union if wages in both countries are flexible and labor in both countries is mobile. Mundell's theory suggests that if neither condition holds, then the only policy instrument left to restore equilibrium in the face of economic shocks is currency valuation. The theory suggests that countries with complementary labor market institutions and growth rates are likely to benefit from monetary union, while countries with more heterogeneous labor markets and economic growth patterns are less likely to benefit.

Utility control areas in the United States are, of course, different from countries in Europe, and Mundell's original theory of optimal monetary unions has been highly criticized. But evaluating the extent of the gains from regional electric grid integration can be viewed as a similar problem. Properties or policies of individual utility systems may be complementary, in which case joint dispatch and generation control through an institution such as an RTO may be beneficial. We will discuss some specific complementarities and conflicts in section 5, but we now turn to what quantitative evidence exists concerning the benefits of moving towards an RTO-centered industry structure.

IV. Evidence on the Benefits and Costs of Regional Electric Grid Integration

Preliminary estimates indicated that the regional integration and centralized RTO spot markets would benefit consumers, just as deregulation and the promotion of markets benefited consumers in natural gas, airlines, railroads, and trucking.[26] Increased operating efficiencies and competition were expected to decrease costs and consumer rates by around ten percent. The results have been far less certain. Only a handful of studies have attempted to measure whether

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currency union is given by PAUL DE GRAUWE, THE ECONOMICS OF MONETARY INTEGRATION (Oxford University Press 1997).

26. Winston, *supra* note 6.

the move towards regional integration has yielded net benefits or net costs. Part of the controversy stems from the lack of an agreed-upon metric to measure the effects of regional grid integration. Policymakers, by and large, have not been clear as to the policy goals that restructuring was supposed to meet.[27] Cost control was likely a major motivator; the states that pursued restructuring most eagerly were, by and large, the states that had the highest electric rates.[28] Some states, however, appeared to be pursuing other goals through restructuring, such as trying to encourage increased operating efficiency, conservation in consumption, or renewable energy.[29] But for the most part, industry restructuring and the establishment of markets appears to have been the policy goal in and of itself.[30]

A handful of studies have tried to estimate the effects of some aspects of restructuring. None of the studies are comprehensive in the sense of including the effects of vertical dis-integration, RTO markets, RTO grid management, changes in rate structures and financial incentives, and retail competition all in the same paper. This section focuses on the existing literature evaluating the effects of RTO markets and regional grid integration. Broadly, the existing literature considers three outcome variables: the effects on regional energy markets; the effects on operational efficiency; and the effects on prices paid by consumers. Other aspects of industry restructuring, such as its effect on mergers and acquisitions, and effects on financial and accounting standards, have not been as well-studied.[31]

27. Lester Lave, Jay Apt, & Seth Blumsack, *Rethinking Elec. Deregulation*, 17 ELECTRICITY JOURNAL 11 (2004) [hereinafter *Rethinking Deregulation*]; Seth A. Blumsack, Jay Apt, & Lester Lave, *Lessons from the Failure of U.S. Elec. Restructuring*, 19 ELECTRICITY JOURNAL 15 (2006) [hereinafter *Lessons*].

28. PAUL JOSKOW, CTR. FOR ENERGY & ENVT'L POLICY RESEARCH, THE DIFFICULT TRANSITION TO COMPETITIVE ELEC. MKTS. IN THE U.S. (2003), *in* ELECTRICITY DEREGULATION: CHOICES AND CHALLENGES (J. Griffin & S. Puller, eds., University of Chicago Press 2005) [hereinafter Joskow]; Seth Blumsack, Jay Apt, & Lester Lave, *A Cautionary Tale: U.S. Electric Sector Reform,* 40 ECONOMIC AND POLITICAL WEEKLY 5279 (2005) [hereinafter *A Cautionary Tale*].

29. 66 PA. CONST. STAT. § 2801 (2004).

30. *See Rethinking Deregulation* and *Lessons*, *supra* note 27 (referring to this as "faith-based deregulation")

31. These studies are reviewed in JOHN KWOKA, AM. PUB. POWER ASS'N, RESTRUCTURING THE ELEC. POWER SECTOR: A REVIEW OF RECENT STUDIES (2006), http://www.appanet.org/files/PDFs/RestructuringStudyKwoka1.pdf.

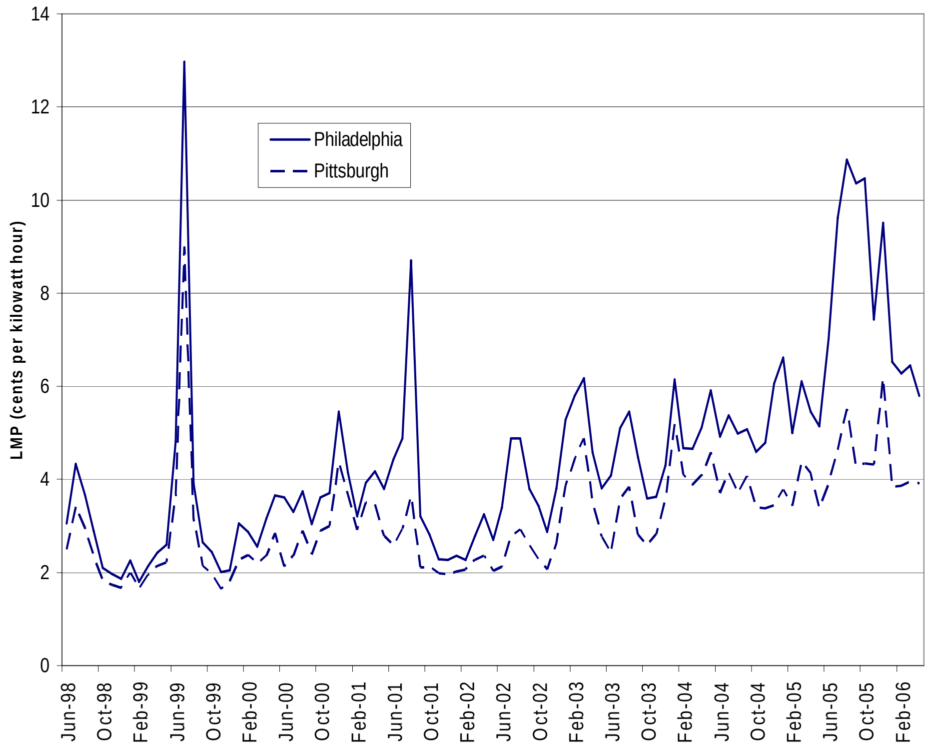

Figure 4: Market prices in Eastern and Western Pennsylvania. The Philadelphia price represents the PECO PJM pricing point, while Pittsburgh represents the Duquesne PJM pricing point.

A. Effects on Regional Energy Markets

The hallmark of regional market and grid integration under the RTO structure is that the centralized economic dispatch of generation resources covers a wider geographic footprint. It is not hard to see how joint dispatch of multiple utility control areas could yield benefits to consumers in the form of lower prices. Particularly in the Eastern United States, some geographic regions are blessed with a surplus of inexpensive generation resources, while others suffer from relative scarcity. Prevailing prices will differ accordingly. Western Pennsylvania, for example, has abundant inexpensive coal generation, and the shutdown of the steel industry in the 1980s brought a large energy surplus to the region. Eastern Pennsylvania, on the other hand, does not have a similar resource endowment, and thus had to invest in more nuclear generation for baseload power, and oil-fired and natural gas units to serve peak demand. The higher cost of Eastern Pennsylvania power versus Western Pennsylvania power is shown in Figure 4, which shows locational prices in PJM in several utility control areas. Clearly, consumers in Eastern Pennsylvania would benefit from increased access to inexpensive generation in the Western half of the state. Open transmission access combined with a regional dispatch is one way to meet this goal.[32]

32. Of course, this might also mean that consumer prices in Western Pennsylvania would increase, as would generator revenue. If the generation owners in Western Pennsylvania could transfer some of their profits to consumers, perhaps through lower rates, this could offset the otherwise higher prices. There is little evidence or perception that this has actually happened. *See* JAY APT & LESTER LAVE, ALLEGHENY

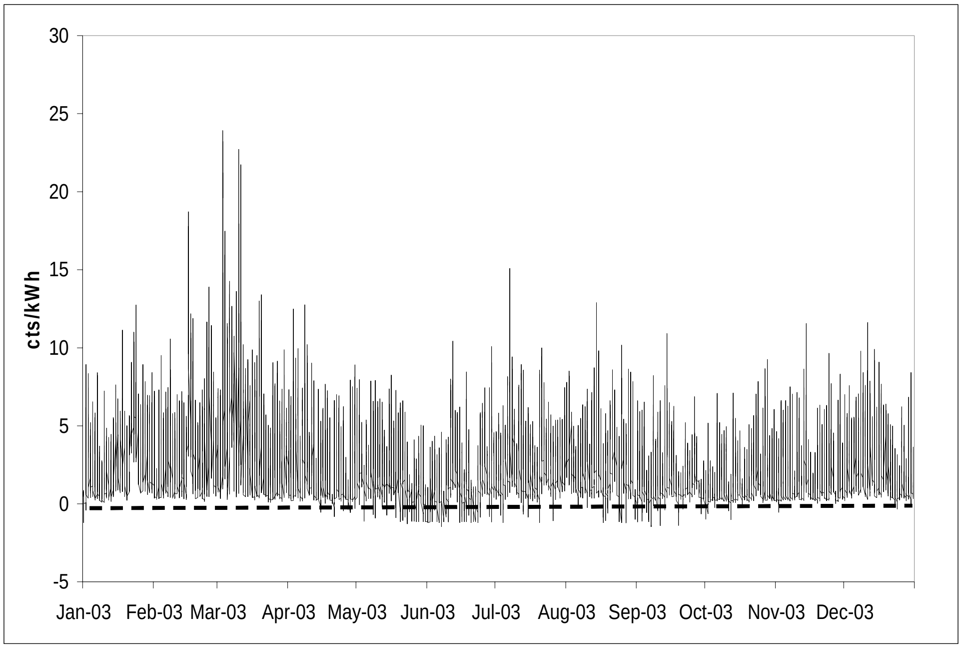

Figure 5. Generators in SERC could often make money selling into the PJM market. The figure plots the difference between the hourly market price in PJM and the marginal cost of generation in SERC (at the level of hourly demand in PJM). Marginal costs are calculated using average heat rates from the EPA's E-GRID database, and PJM load and market price data is from PJM. The calculations assume a coal price of $25/ton, oil at $55/bbl, and natural gas at $5/mmbtu. The marginal costs of nuclear, hydro, and wood/waste facilities are assumed to be 3.5cts/kWh, 1.5cts/kWh, and 4cts/kWh.

The potential gains from trade are not limited to localized regional gains, such as from one part of Pennsylvania to another. Figure 5 shows the potential revenue opportunities for generators in the Southeastern United States selling into the PJM. The figure plots the difference between the marginal cost of generating power in the Southeast, and the average LMP in PJM, based on 2003 demand levels in PJM. The figure does not include any transmission access charges, nor does it consider explicit transmission constraints, due to lack of publicly-available data. The Southeastern United States has thus far stubbornly resisted moving towards the FERC-preferred model of RTO transmission management and regional grid integration. Generation is still dispatched at the level of the individual utility control area. The figure demonstrates that, given sufficient transmission access, generators in the Southeast and consumers in PJM could potentially gain from a joint dispatch encompassing both regions. PJM's recent westward and southern expansion has aimed to bring low-cost resources into the PJM dispatch stack.

Even without the RTO structure, existing evidence suggests that low-cost generators outside of the PJM footprint have increased sales into the PJM market. Robert Thomas has examined the effects of PJM's market structure on power flows and trade in the Southeastern United States. He shows that power

CONFERENCE ON COMMUNITY DEV., ENERGY OPTIONS FOR LARGE INDUSTRIAL CUSTOMERS IN W. PA (2005) [hereinafter ALLEGHENY CONFERENCE]. In practice, transmission constraints have limited the amount of power that can be transferred to the eastern seaboard from the coal-rich areas of the Midwest.

transfers (known as "wheeling") across the TVA territory have increased since the opening of PJM's regional power market. Thomas's findings are reproduced here as Figure 6. A significant portion of these wheeling flows are likely due to Southeastern and Midwestern low-cost resources selling into the PJM market.[33]

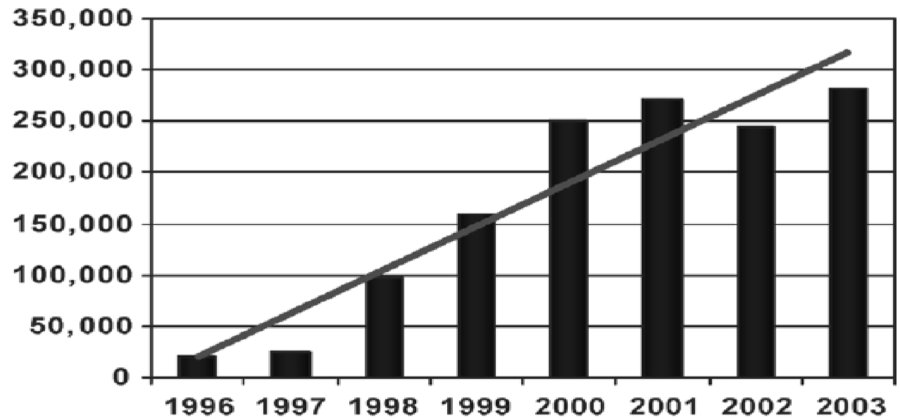

Figure 6: Wheeling across the TVA territory. Source: R. THOMAS, J. WHITEHEAD, H. OUTHRED, AND T. MOUNT, INSTITUTE OF ELECTRICAL AND ELECTRONIC ENGINEERS, TRANSMISSION SYSTEM PLANNING – THE OLD WORLD MEETS THE NEW (2005).

Two studies have taken a broad look at the effects of centralized regional power markets on wholesale electric energy prices. These studies differ from the rest of the existing literature in that they explicitly consider the transmission effects of restructuring and regional grid integration by running a series of power flow simulations. The first, from Energy Security Analysis, Inc., uses a network model of PJM to evaluate the effect on PJM's territorial expansion.[34] They conclude that expanding the scope of regional dispatch in the PJM market has encouraged trade, particularly with the integration of low-cost areas such as Allegheny Energy and American Electric Power. Interface flows between these areas and the original PJM footprint have increased by around fifteen percent and twenty-five percent.[35] Increased trade and generation efficiency[36] has yielded consumer benefits on the order of $500 million per year.[37]

The second study, from ICF consulting and commissioned by the FERC,[38] uses a proprietary power flow model to evaluate the gains from electric grid integration at wide regional and national levels. Its findings are similar to the ESAI study in that regional grid integration along the FERC-preferred RTO

33. As discussed below, the change in flow patterns brought on by RTO markets has come with its own set of associated problems. Increased wheeling across the TVA territory has brought TVA revenue in the form of transmission access charges, and has benefited low-cost generators in the Southeast and high-cost consumers in PJM. But it has also contributed to voltage problems within the TVA territory, as described in R. Thomas, J. Whitehead, H. Outhred, & T. Mount, *Transmission System Planning – The Old World Meets the New*, 93 INSTITUTE OF ELECTRICAL AND ELECTRONIC ENGINEERS 2026 (2005).

34. ENERGY SECURITY ANALYSIS, INC., IMPACTS OF THE PJM RTO MARKET EXPANSION (2006) [hereinafter ESAI].

35. *Id.* § 6.

36. The ESAI study measures generation efficiency using average heat rates, which indicate the amount of fuel needed to generate one kilowatt hour. Page 7 of the study estimates that generation efficiency increased by almost twenty percent since 2001.

37. *See* ESAI, *supra* note 34, § 5.

38. ICF CONSULTING, ECONOMIC ASSESSMENT OF RTO POLICY (2002) [hereinafter ICF].

model brings large benefits to consumers. ICF calculates that RTO integration has a net present value of approximately $40 billion, with most of the savings coming through increased market efficiency, better planning processes, and increased demand response.[39] Benefits appear to be strictly increasing with the geographic scope of regional grid integration; that is, larger RTOs are always better.

A critical evaluation of these studies is difficult, since they use proprietary data and power flow models. Their results are not inconsistent with the data shown in Figures 5 and 6, but cannot escape the inevitable "black box" critique. It is notable that no work similar to the ESAI or ICF studies has appeared in the peer-reviewed academic literature.

B. Studies Examining the Effects on Operational Efficiencies

There is a difference between lowering prices and lowering costs. Prices can be lowered easily by dictates from public officials, as happened in many restructured states. The real consumer benefits to competition, however, come from lower costs associated with increased operational efficiency. One of the primary virtues of competitive markets is that they encourage firms to increase productivity and efficiency without increasing costs. Low-cost firms will prosper, while high-cost firms will be forced out of the market.

The major inputs to generating electricity are capital, fuel, and labor. Fuel markets are sufficiently liquid and well-established that individual generation owners are unlikely to be able to significantly affect prices in these markets. Thus, increased efficiencies in fuel purchasing are unlikely following restructuring and regional grid/market integration. Figure 3 shows the relationship between natural gas prices and gas-fired generation.[40] There is some evidence that regional grid integration and the introduction of regional electricity markets has increased the operating efficiency of large baseload power plants, particularly coal-fired and nuclear plants. As discussed below, the uniform-price auction structure used in every FERC-approved regional power market does provide incentives for baseload plants to increase the number of hours in which the plant is available to produce electricity. The uniform-price auction pays all dispatched generation based on the marginal cost of the last unit dispatched. Particularly during peak hours, these "marginal units" are often natural-gas generators, with much higher fuel costs than coal or nuclear units. Every hour that a gas-fired generator is dispatched at a cost of, say $60/MWh, a nuclear or coal-fired unit that is dispatched will be paid based on the $60/MWh cost of the gas-fired unit rather than the marginal cost of its own generation, which may be closer to $20/MWh.[41] Thus, there are ample incentives for large generators to maximize their availability in a competitive electricity market.[42]

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39. The findings are summarized in ICF, *supra* note 38, at vi.

40. Coal prices have also increased somewhat, though with far less volatility than natural gas. The recent profitability of large nuclear power plants in the U.S., as well as a more general interest in nuclear power worldwide, has cause uranium prices to increase dramatically in the last several years. *See* the *Nuclear Energy Overview*, October 30, 2006.

41. In this example, the coal and nuclear units would not be paid exactly $60/MWh—they are paid their locational marginal price (LMP), which depends on the dispatch pattern throughout the network. The point is that they will likely be paid significantly more than the average-cost payments earned under regulation.

42. When firms can exercise market power, the incentives are clearly altered. Generators may find it advantageous to keep less expensive generation off the grid to push up the market-clearing price. *See* Paul L. Joskow & Edward Kahn, *A Quantitative Analysis of Pricing Behavior In California's Wholesale Elec. Mkt. During Summer 2000*, 23 ENERGY JOURNAL 1 (2002); Seth Blumsack, Dmitri Perekhodtsev, & Lester B. Lave,

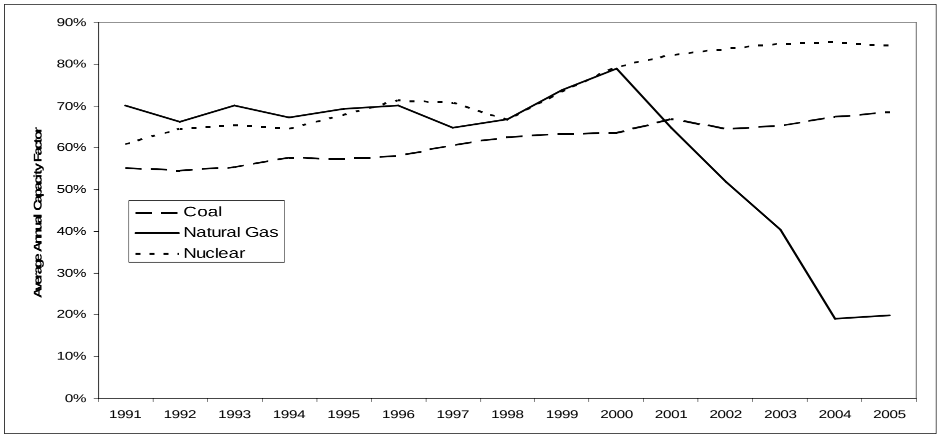
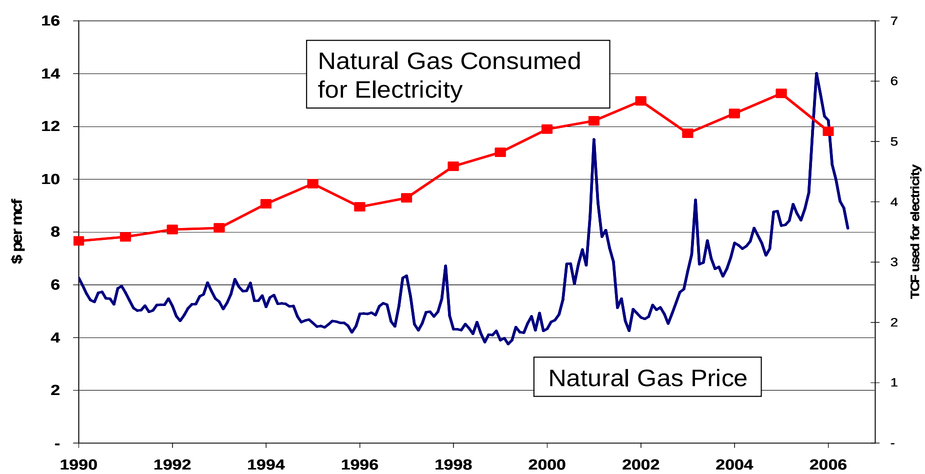


Figure 7: Average annual capacity factors for coal, natural gas, and nuclear generation. Source: Energy Information Administration.

One useful measure of operating efficiency is a generator's annual capacity factor—the amount of output it actually produces divided by the maximum amount that it could possibly produce if it ran at full capacity during every hour of the year. Figure 7 shows the average annual capacity factor for the coal-fired, gas-fired, and nuclear power fleet in the United States between 1990 and 2005. The capacity factors of coal and nuclear generation have been steadily increasing since the late 1990s, when regional electricity markets opened up in the Eastern United States. The capacity factor of natural gas, however, has decreased dramatically, reflecting the gas-building boom in the 1990s; high fuel prices have left many of these plants unable to compete, as shown in Figure 8.



Market Power in Deregulated Wholesale Elec. Mkts.: Issues in Measurement and the Cost of Mitigation, 15 ELECTRICITY JOURNAL 11 (2002); SAROSH TALUKDAR, T. MOUNT, & SHMUEL OREN, POWER SYS. ENG'G RESEARCH CENTER, SOFTWARE AGENTS FOR MKT. DESIGN AND ANALYSIS (2005), http://www.pserc.org/cgi-pserc/getbig/publicatio/reports/2005report/talukdar_biddingagents_final report_m6.pdf [hereinafter Talukdar].

Figure 8: Natural gas consumption for electricity generation and the price of natural gas. Source: Jay Apt, from Energy Information Administration Data.

A closer look at the nuclear power industry demonstrates that there has been a second-order effect in efficiency gains related to mergers and acquisitions. Figure 9 shows capacity factors in the nuclear industry for different sized firms through 2003. Nuclear generators of all sizes have gotten more efficient, but the larger firms—defined as those owning more than three nuclear power stations—increased their efficiency at a faster pace.[43] This suggests the existence of scale or scope economies in generation-plant management. Efficiency gains will result if talented managers are put in charge of large numbers of plants. Antitrust authorities are naturally concerned with the possible competitive effects of horizontal integration through increased merger and acquisition activity, but the competitive effects should be weighed against possible efficiency losses from limiting scale or scope economies.

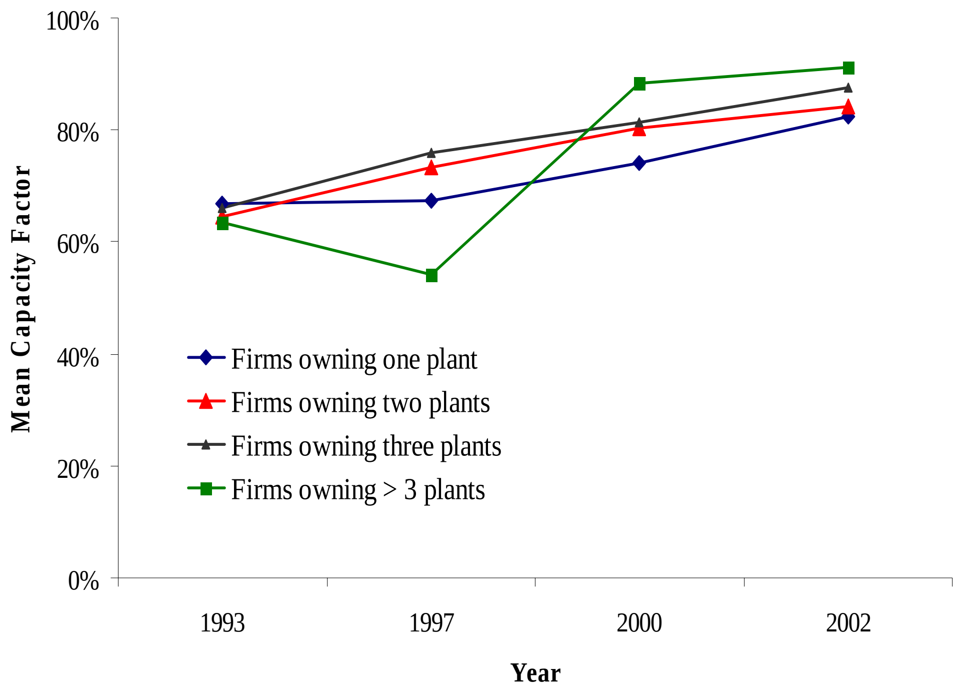


Figure 9: Larger firms have become more efficient at a greater pace in the nuclear power industry. Source: S. BLUMSACK & L. LAVE, U.S. ASSOCIATION FOR ENERGY ECONOMICS, MITIGATING MARKET POWER IN RESTRUCTURED U.S. ELECTRICITY MARKETS (2004).

Measuring efficiency gains in the nuclear power sector is a reasonably straightforward exercise since nuclear power operators in the United States tend to want to run their units continuously between refueling outages. Cycling a nuclear power plant, as for a peaking unit, is possible, but since the units are so

43. The data in Figure 9 includes refueling outages. In 2005, the average capacity factor for the U.S. nuclear industry was well over ninety percent. The average length of a refueling outage at a nuclear plant has declined from three months to one month. Further large efficiency gains are therefore unlikely.

large there is an associated loss of efficiency and higher fuel consumption.[44] Adjustments in the output of a nuclear power plant need to be reported and justified to the United States Nuclear Regulatory Commission. Thus, many nuclear power plants are run under long-term contracts or under pre-existing regulatory "must-run" agreements. Coal plants, on the other hand, are less tightly regulated and are more heterogeneously sized, and used to serve different segments of the load profile. Thus, a given coal plant may start up or shut down for any number of reasons, not just because it is being run inefficiently. Stratford Douglas has closely examined the efficiency gains in the utilization of coal-fired power plants between 1981 and 2000.[45] He finds a significant relationship between whether a given plant is dispatched as part of an RTO and its capacity factor, with efficiency gains of between one percent and three percent in RTO systems as compared to traditionally-organized and regulated systems.[46] Similarly, a study by James Bushnell and Catherine Wolfram suggests that fossil-fuel plants in areas with regional power markets tended to operate slightly more fuel-efficiently, with estimated efficiency gains of around two percent.[47]

There appear to have been documented savings in labor costs since restructuring. For instance, Morgan, Apt, and Lave report that the number of electric-sector employees has fallen by nearly twenty-five percent since the 1980s, and by ten percent since the onset of restructuring.[48] Meanwhile, demand has grown by about ten gigawatt-hours per year since the 1980s. This translates into a productivity increase (measured in output per employee) of nearly sixty percent. About ten percent of this productivity increase has occurred since the mid 1990s. There is some emerging evidence that non-utility plants have significantly lower work forces than utility-owned plants.[49] Depending on how employment is measured, the difference has been estimated to be as large as seventy percent.[50] However, the existing literature comparing the merchant and utility generation sectors does not take into account the deteriorating financial position of the merchant sector, nor the fact that many of the merchant plants are new gas-fired units, which have been hurt by high fuel prices and are not dispatched as often as similarly-sized coal plants. Since the merchant generation sector may have a lower capacity factor than the utility generation sector, it should not be surprising that fewer people are employed at merchant plants.

C. Studies Examining the Effects of Regional Integration on Retail Electricity

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44. The issue here is not simply higher fuel costs. Spent nuclear fuel must still be stored on-site, and permitted storage space at most nuclear facilities is limited.

45. Stratford Douglas, *Measuring Gains from Regional Dispatch: Coal-Fired Power Plant Utilization and Market Reforms*, 27 ENERGY JOURNAL 119 (2006).

46. *Id*. at 136-37. Douglas suggests that the estimated efficiency gain would increase with the inclusion of more recent data. This observation is consistent with the capacity factor data shown in Figure 4.

47. James Bushnell & Catherine Wolfram, *The Impact of Elec. Generating Plant Divestitures on Operating Performance*, *in* Catherine Wolfram, *The Efficiency of Electricity Generation in the U.S. After Restructuring*, ELECTRICITY DEREGULATION: CHOICES AND CHALLENGES, (James M. Griffin & Steven L. Puller eds., University of Chicago Press 2005).

48. Granger Morgan, Jay Apt, & Lester Lave, Pew Ctr. on Global Change, The U.S. Electric Power Sector and Climate Change Mitigation (2005), *available at* http://www.pewclimate.org.

49. JENNIFER KAISER SHANEFELTER, UNIV. OF CAL. ENERGY INST., CENTER FOR THE STUDY OF ENERGY MKTS., RESTRUCTURING, OWNERSHIP, AND EFFICIENCY: THE CASE OF LABOR IN ELEC. GENERATION (2006), http://www.ucei.berkeley.edu/PDF/csemwp161.pdf.

50. Data on power-sector employment following restructuring is difficult to come by, since many non-utility generators do not participate in the employment surveys conducted by the Bureau of Labor Statistics.

Prices

Economists like competitive markets because the benefits of lower costs and increased efficiency are passed on to consumers in the form of lower prices. By far, the largest group of studies seeking to measure the effects of restructuring and regional market integration are concerned with the effect on the retail price of electricity. While most of the studies take a national view (the analyses are not just focused on a single state or group of states), their conclusions are far from unanimous. There is, however, a striking similarity in the conclusions of academics versus the conclusions of consultants. Price studies from consulting firms or industry groups, such as the Center for Advancement of Energy Markets;[51] Cambridge Energy Resource Associates;[52] Global Energy Decisions;[53] and LECG,[54] all find that consumers have benefited tremendously under restructuring, with rate savings in the billions of dollars. Studies by academics, including Jay Apt;[55] Paul Joskow;[56] and John Taber, Duane Chapman, and Tim Mount[57] offer a less favorable picture. While Apt, Taber, Chapman, and Mount find no evidence that restructured states have seen lower prices than regulated states, Joskow's econometric model does show a benefit, but it is much smaller than those suggested in the consultants' reports.[58]

From a statistical or econometric point of view, estimating the effects of restructuring on price is an extremely challenging problem. First, correlation is easy to establish, but causation is not, at least in the statistical sense. Formal econometric causation tests do exist, but have not been employed in any of the studies examining the effect of restructuring on retail prices.[59] Even so, proper statistical use of these causation tests requires that the statistical model employed is the correct model. That is, the causation test assumes that the mathematical form of the statistical model is correct, and that all relevant explanatory variables have been accounted for.

Second, the political and regulatory process of restructuring is difficult to compress into a single explanatory variable. Many of the econometric price studies choose a single date as a break-point for each market; prior to the break-point the market is described as a vertically integrated and regulated utility, while after the break-point the market is described as being somehow

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51. DR. RONALD J. SUTHERLAND, CENTER FOR THE ADVANCEMENT OF ENERGY MKTS., ESTIMATING THE BENEFITS OF RESTRUCTURING ELEC. MKTS.: AN APPLICATION TO THE PJM REGION (2003), http://www.caem.org/website/pdf/PJM.pdf [hereinafter CAEM].

52. CAMBRIDGE ENERGY RESEARCH ASSOCS., BEYOND THE CROSSROADS: THE FUTURE DIRECTION OF POWER INDUSTRY RESTRUCTURING (2005).

53. GLOBAL ENERGY DECISIONS, PUTTING COMPETITIVE POWER MKTS. TO THE TEST: THE BENEFITS OF COMPETITION IN AMERICA'S ELEC. GRID: COST SAVINGS AND OPERATING EFFICIENCIES (2005), http://www.globalenergy.com/competitivepower/competitivepower.pdf [hereinafter GED].

54. SCOTT M. HARVEY, BRUCE M. MCCONIHE, & SUSAN L. POPE, ANALYSIS OF THE IMPACT OF COORDINATED ELEC. MKTS. ON CONSUMER ELEC. CHARGES, http://www.ksg.harvard.edu/ hepg/Papers/LeCG_Analysis_112006pdf.pdf.

55. Jay Apt, *Competition has Not Lowered U.S. Indus. Elec. Prices*, 18 ELECTRICITY JOURNAL 52 (2005).

56. Paul J. Joskow, *Markets for Power in the United States: An Interim Assessment*, 27 ENERGY JOURNAL 1 (2006) [hereinafter *Markets for Power*].

57. JOHN TABER, DUANE CHAPMAN, & TIM MOUNT, DEPT. OF APPLIED ECONOMICS AND MGM'T, EXAMINING THE EFFECTS OF DEREGULATION ON RETAIL ELECTRICITY PRICES (2005), http://aem.cornell.edu/research/researchpdf/wp0514.pdf.

58. *Markets for Power*, *supra* note 56, at 33.

59. One such concept is outlined in C.W.J. Granger, *Investigating Causal Relations by Econometric Models and Cross-Spectral Methods*, 37 ECONOMETRICA 424 (1969).

"deregulated" or "restructured." Such a break-point analysis might be acceptable for California, whose restructuring law created a set of markets and allowed for full retail competition for all customer classes virtually overnight. Meanwhile, New York phased-in retail competition over a period of at least three years. Thus, studies that use break-point variables ignore some of the important dynamics of the restructuring process. An additional issue is that having a single variable that labels certain states as being "restructured" or "regulated" in a given year ignores the variety of different approaches taken in each state. Some state restructuring laws were reasonably minor, affecting only a small number of customers. Oregon, for example, allowed retail competition only for its largest customers.[60] PJM has very different market rules and institutions than does Texas or California.

A third challenge concerns the customer classes studied. Estimating the effect of competition in the residential sector is extremely difficult, since residential prices are tightly controlled by public utility commissions (even in supposedly "deregulated" states). Further, since residential expenditures on electricity are typically small relative to income, there may not be much room for savings, especially if all competitive suppliers are buying power at the same price from the same market.[61] In regulated states, cross-subsidization among rate classes also exists, which is not statistically accounted for in any of the literature.[62]

The most important challenge concerns the correct price comparison. The relevant policy question is not whether electricity prices are lower, higher, or unchanged in the restructured era, but rather whether prevailing prices under restructuring have been higher or lower than the prices that would have prevailed had the industry remained regulated. Thus, correctly evaluating the effects of restructuring and the establishment of regional power markets involves constructing a counterfactual (an estimate of what would have happened to electricity prices in the absence of restructuring). Some of the studies, such as the LECG study and the Joskow study, attempt to provide an explicit counterfactual or a more general statistical model of retail electricity prices. Others, such as the Apt study and the Taber, Champman, and Mount study do not construct an explicit counterfactual, but instead examine how the rate of change of retail electricity prices changed with the onset of restructuring.[63] The other common pitfall in the existing price studies is ignoring a wide variety of regulatory interventions into the retail electricity market following the implementation of restructuring. The most common of these on the utility side are allowances for stranded costs. On the consumer side, rates were often capped, frozen, or even reduced during a transition period (usually corresponding to an allowed time for the incumbent utility to retire its stranded costs).

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60. S. 1149, 70th Cong. (Or. 1999); amended by H.R. 3633, 71st Leg. (Or. 2001).

61. KENNETH ROSE, VIRGINIA STATE CORP. COMM'N, 2005 PERFORMANCE REVIEW OF ELECTRIC POWER MARKETS: UPDATE AND PERSPECTIVE (2005), http://www.scc.virginia.gov/caseinfo/pue/case/status reportpart4presentlttf.pdf; *Lessons*, *supra* note 27.

62. Of course, actions by individual state utility commissions may involve cross-subsidies in restructured states as well.

63. This approach, known in the econometric literature as a "differences in differences" model, is commonly used in studies of institutional or structural shifts in policies or markets over time. These types of studies have nonetheless been criticized for not constructing a statistical counterfactual. A fairly thorough criticism can be found in JOHN KWOKA, AM. PUBLIC POWER ASS'N, RESTRUCTURING THE U.S. ELECTRIC POWER SECTOR: A REVIEW OF RECENT STUDIES (2006).

D. Summary of Existing Work on the Benefits and Costs of Regional Grid Integration

It has been nearly ten years since the new institutions and markets introduced by electric restructuring have appeared. The amount of controversy over restructuring suggests that there is no clean-cut consensus on what its benefits have been, if any. Taken as a whole, the existing evidence in the literature would suggest the following:

Regional grid integration and RTO markets have increased the efficiency of the wholesale electric market, by lowering barriers to trade and increasing the utilization of low-cost generation resources. If we take as a representative figure $1 billion per year in long-term national annual savings,[64] this works out to an average cost savings of roughly two cents per kilowatt-hour, assuming 100 million megawatt-hours of annual United States demand.[65]

Operating efficiency of baseload units with low marginal costs has been improved by regional grid integration, but the efficiency of peaking units (particularly natural gas generation) with high marginal costs has decreased.[66]

Generating companies whose assets include large amounts of low-cost baseload generation have been highly profitable and have been rewarded by the market.[67]

The evidence on retail prices is the most difficult to summarize, since there are equally good estimates that consumer prices have increased and decreased in states that have chosen restructuring. Further, the mix of regulatory interference and fuel-price effects make it extremely hard to determine if restructuring or some other influence is largely responsible for the observed changes in retail prices. What can be taken from the existing literature is that, to date, the estimated retail price effects (positive or negative) associated with restructuring have been reasonably small.[68]

Overall, we see evidence that operating efficiencies have likely increased (and costs have likely decreased) with the move towards regional grid integration and RTO markets, but these cost declines on the production side have not translated into declining prices on the consumer side. Efficient and beneficial commodity markets do not appear overnight; they often take many years of experimentation and effort. Even so, the lack of consensus after ten years of experience with centralized regional power markets, and the mixed signals in the evidence on costs and prices, suggests that there may be other factors (as yet unmeasured or poorly measured) at work. We now turn to a discussion of some of these other influences.

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64. *See* ICF, *supra* note 38; CAEM, *supra* note 51.

65. The figure on U.S. demand is 2005 data from the Energy Information Administration. *See* ENERGY INFO. ADMIN., ELEC. POWER ANNUAL (2005), http://www.eia.doe.gov/cneaf/electricity/ epa/epa.pdf.

66. I am grateful to a referee for providing the specific example of New York, where forced outages have decreased by half since the state's utilities divested nearly all of their generation assets to non-utility suppliers.

67. Stock in Exelon, for example, has increased in value an average of twenty-eight percent per year since 1998. *See* EDWARD BODMER, AM. PUBLIC POWER ASS'N, THE ELEC. HONEYPOT: THE PROFITABILITY OF DEREGULATED ELEC. GENERATION COMPANIES 3 (2007), http://www.appanet.org/files/PDFs/BodmerElectric HoneypotExexSummary.pdf.

68. Recent large proposed and actual retail price increases in restructured states such as Illinois, Maryland, Pennsylvania, and Texas may alter this conclusion somewhat.

V. OTHER BENEFITS AND COSTS

This paper is focused on identifying and evaluating specific complementarities and conflicts between individual utility control areas which might yield benefits or costs following integration into an RTO-type structure. A review of the existing theory and evidence in sections 3 and 4 suggests that high-cost areas would benefit from operational integration with low-cost areas. Production cost should go down in the high-cost areas, but might increase in the low-cost areas. Another requirement if regional grid integration is to yield benefits is a connection between costs and prices. Assume that a high-cost area joins an RTO along with a low-cost area. Consumers in high-cost areas should see their prices go down. Consumers in the low-cost areas will see their prices increase, but only to the extent that higher profits to low-cost generators are not somehow redistributed. The extent of both types of welfare gains (costs and prices) will be limited by the mobility of generation output, i.e., by the extent of the transmission network.

This section describes a number of other factors which should figure into the cost-benefit calculation for regional grid integration. These include the direct costs of operating RTOs, complementarities in regional demand patterns, the disconnect between wholesale and retail pricing, environmental effects, and the special problems with hybrid systems.

A. Direct Costs of RTO Operation

RTOs have involved substantial start-up and operations costs. One of the primary functions of the RTO involves running a constrained economic dispatch and calculating the associated LMPs, sometimes as frequently as every five minutes. This mathematical optimization problem does not always have an easy solution, and can be computationally intensive to solve when the system gets very large. There are also significant tradeoffs between realism and parsimony. The physics of AC power flow are highly complex and nonlinear. Linear approximations exist which can reduce the computational complexity significantly.[69] However, these approximations can be quite poor when the system is stressed or in the case of outages at generators or transmission lines. Since these are the times when accurate LMPs are needed the most, most RTOs use software and algorithms which incorporate as much of the system information as possible. Developing this software is a time-consuming and expensive task.

69. For a highly technical discussion of these approximations, *see* ALLEN J. WOOD & BRUCE WOLLENBERG, POWER GENERATION, OPERATION, AND CONTROL (2d ed., John Wiley & Sons, Inc. 1996).

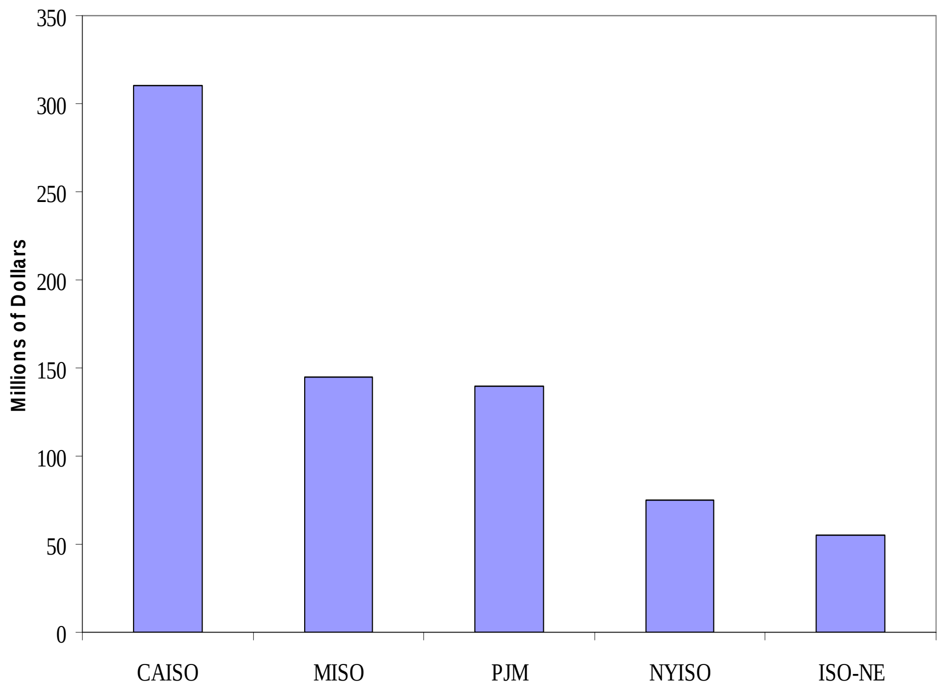

Figure 10: ISO and RTO Start-Up Costs. Comparative Analysis of RTO/ISO Operating Costs, Public Power Council 7 (2004).

California's power crisis in 2000/2001 focused attention on the role of market monitoring in ensuring that RTO spot markets behaved competitively. Most RTOs now have a fairly substantial and aggressive set of market monitoring protocols. But enforcing the rules has required large investments in personnel and software to analyze (and if necessary, correct) generator bids.

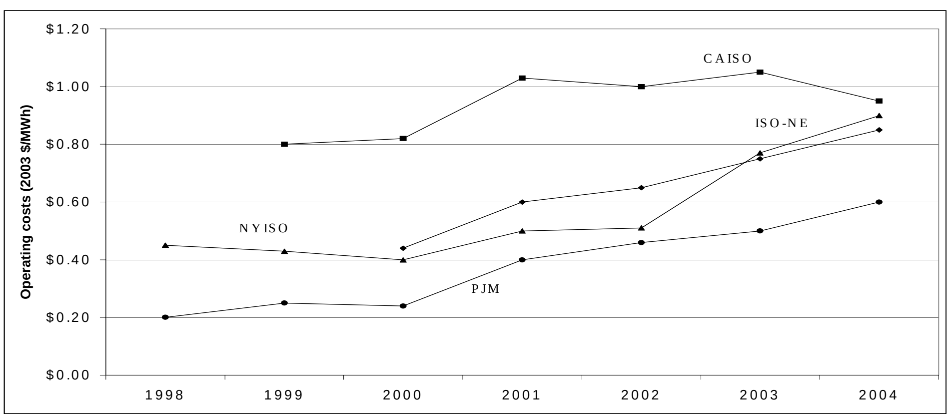

Figure 11: ISO and RTO Start-Up Costs. COMPARATIVE ANALYSIS OF RTO/ISO OPERATING COSTS, PUBLIC POWER COUNCIL 4 (2004).

Figures 10 and 11 show the start-up and operating costs (total start-up costs and per-MWh operating costs) of United States RTOs. The costs associated with RTO operations are certainly substantial, but as a percentage of market prices are fairly small. The average PJM LMP in 2004 was $42/MWh, so the operations costs of PJM have amounted to $0.9 per MWh, or less than two percent of the market price.[70] For the most part, start-up costs have been roughly equal to one year's worth of operations costs.[71] It is not clear how these costs have been amortized over time, although paying them off over a small number of years would not significantly increase costs.

B. Complementarities in Regional Demand

The theory of optimal currency areas described in section 3 suggested that economies with complementary attributes would do better under monetary union than those with highly heterogeneous attributes. The same principle holds for local electrical systems considering joining an RTO. Just as labor must be free to move across borders in a system of currency union, energy must be able to flow reasonably unimpeded across system boundaries in order for joint dispatch to yield benefits. Thus, the extent of the transmission grid represents another limit to regional grid integration.

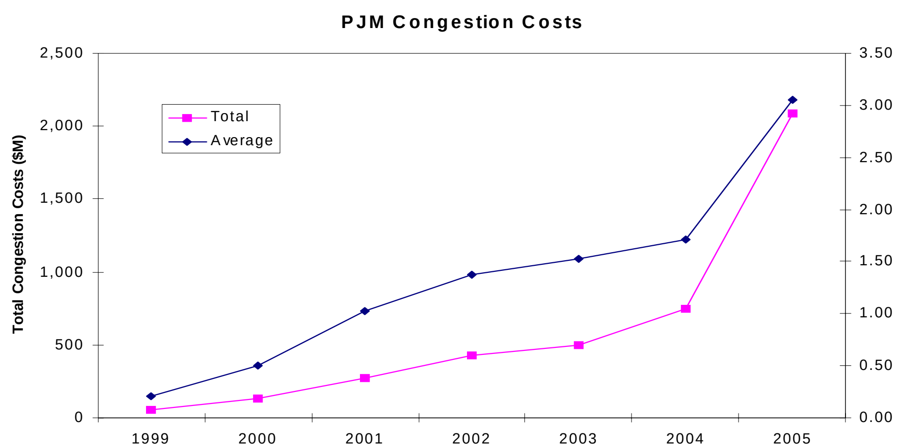

Figure 12: Total and average congestion costs have been increasing in PJM. Source: 2005 STATE OF THE MARKET REPORT, PJM INTERCONNECTION (2006), *available at* http://www.pjm.com/markets/market-monitor/som.html.

In many circumstances, enjoying the benefits that may rise out of regional market and operations integration requires a significant amount of new transmission investment. Following the Midwestern and Eastern blackout of August, 2003, the Electric Power Research Institute recommended a large transmission-investment program amounting to $100 billion dollars.[72] The total transmission capacity in the United States is orders of magnitude larger than the total generation capacity, so the exact investment needs for the United States grid is debatable. The problem in many areas is not insufficient transmission

70. Some market participants have reported higher RTO-related charges. Industrial customers in Pennsylvania have apparently been charged up to $10/MWh for load-shaping in PJM. *See* ALLEGHENY CONFERENCE, *supra* note 32. These charges appear to have either been transitory or have been phased out.

71. There appears to be a great deal of uncertainty surrounding the startup costs for the California ISO. Other estimates include $170 million by the Control Area Coalition. *See California Independent System Operator Corporation*, 116 FERC § 61,274 (2006); *and* Van Vactor, *supra* note 8 ($ 1 billion).

72. 2003 ELEC. TECHNOLOGY ROADMAP, ELEC. POWER RESEARCH INST. (2003).

capacity, but that the existing capacity is not configured in a way that would support competitive regional power markets. The transmission grid was built up over a period of several decades to support the needs of the local vertically-integrated utility. Joint dispatch accompanying regional grid integration fundamentally alters the pattern of transmission network usage. Even in reasonably mature RTOs with accepted operating practices and harmonized rules, transmission constraints provide limits to competition. Figure 12 shows the average and total value of these constraints in PJM.

Figure 12 suggests that there are a number of significant transmission constraints in PJM that are limiting the gains from a regional dispatch of generation resources. There is a clear value to relieving some of these constraints, and this value has increased with the incorporation of westward areas in to the PJM footprint. However, transmission investment in PJM has been minimal. PJM and the other RTOs do have transmission and resource planning processes,[73] but implementation of specific investment plans has been hampered by regulatory uncertainty regarding compensation, and by an ill-conceived dependence on the merchant sector to make transmission investments.[74]

Thus, unless PJM can find a way to get valuable west-to-east transmission lines built, the value of its westward expansion will be extremely limited. This does not necessarily mean that all other RTOs need to embark on massive investment programs. Transmission capacity is one element of the complementarity required for regional grid integration to yield benefits, but the transmission required needs to be compared to regional patterns of demand. Complementary load patterns over time can act as a substitute for additional transmission investment. Integrating multiple systems with highly coincident demands and limited transmission capacity between the systems is unlikely to be beneficial. If systems have non-coincident demands (and if each system has sufficient native generation capacity), then regional grid integration could be beneficial even without overbuilding the transmission grid between the formerly un-integrated systems.

	PJM	NYISO	ECAR	SERC	NEPOOL
PJM	1				
NYISO	**0.92**	1			
ECAR	**0.90**	0.78	1		
SERC	0.87	0.83	0.88	1	
NEPOOL	0.91	0.86	0.84	0.74	1

73. *See generally*, The PJM Regional Transmission Expansion Plan, *available at* http://www.pjm.com/planning/rtep-baseline-reports.html.

74. The case for merchant transmission was originally made by J. Bushnell & S. Stoft, *Electric Grid Inv. Under a Contract Network Regime*, 10 JOURNAL OF REGULATORY ECONOMICS 61 (1996), based on an analysis in W. Hogan, *supra* note 20. Criticism of the merchant model on economic grounds can be found in Shmuel Oren, *Economic Inefficiency of Passive Transmission Rights in Congested Elec. Sys. with Competitive Generation*, 18 ENERGY JOURNAL 63 (1997), and Paul Joskow & Jean Tirole, *Merchant Transmission Investment*, 53 JOURNAL OF INDUSTRIAL ECONOMICS 223 (2005). A critique of the merchant model on engineering grounds can be found in Seth Blumsack, Network Topologies and Transmission Investment Under Electric-Industry Restructuring (May 2006) (Ph.D. Dissertation, Carnegie Mellon University).

Table 1: Demand correlation matrix in the Eastern Interconnect. Source: S. BLUMSACK AND L. LAVE, U.S. ASSOCIATION FOR ENERGY ECONOMICS, MITIGATING MARKET POWER IN RESTRUCTURED U.S. ELECTRICITY MARKETS (2004)

	AZ	CA	NM	OR	WA
AZ	1				
CA	0.90	1			
NM	0.93	0.80	1		
OR	-0.10	**-0.04**	0.10	1	
WA	-0.48	**-0.41**	-0.33	0.77	1

Table 2: Demand correlation matrix in the Western Interconnect. Source: S. BLUMSACK AND L. LAVE, U.S. ASSOCIATION FOR ENERGY ECONOMICS, MITIGATING MARKET POWER IN RESTRUCTURED U.S. ELECTRICITY MARKETS (2004).

Tables 1 and 2 show the correlation of demand in the NERC regions of the Eastern Interconnect, and various states in the Western Interconnect. Table 1 shows that demands in different portions of the Eastern Interconnect are highly correlated. When demand is high in Pennsylvania, it is also high in New York and Ohio. Thus, successful wide-ranging regional grid integration in the Eastern Interconnect is likely to require significant transmission upgrades to promote the free flow of electricity throughout the integrated control area. Table 1 is thus consistent with the PJM transmission constraints shown in Figure 12. Table 2 shows a different picture for the Western Interconnect. In particular, demands in the Pacific Northwest and California are slightly negatively correlated. The negative correlation suggests seasonal complementarities in demand, and is consistent with observed seasonal flow patterns in the West, where abundant hydropower is sold to California during its summer peak, with flow patterns reversing to serve the winter peak in the Pacific Northwest.

C. Wholesale Market Structures that Inherently Raise Costs

As noted in section 4, the evidence suggests that regional electric grid integration has increased the operating efficiency of generators, particularly low-cost baseload units. There is far less conclusive evidence that the cost reductions have been passed on to consumers in the form of lower retail prices. At least part of the reason lies in the auction structure and pricing mechanism used predominantly in regional power markets, known as the uniform-price auction. Figures 13 and 14 demonstrate how the uniform-price auction differs from the average-cost pricing methodology used under regulation.[75] The two figures portray a simplified power system with low-cost baseload generation, medium-cost shoulder generation, and expensive peaking generation. Under traditional rate-of-return regulation, each generator's return is essentially based on its average cost. The total cost of serving the load is given by the shaded area under the system average cost curve.

Regional power markets run by RTOs use a marginal-cost pricing methodology, as shown in Figure 14. Individual generators bid their cost

75. Figures 12 and 13 are based on the analysis of *Rethinking Deregulation*, *supra* note 27.

functions into the RTO spot market; the RTO aggregates the bids vertically to create the system marginal cost function as shown in Figure 14. Where the (vertical) demand curve intersects the marginal cost curve determines which generating units will get dispatched in a given time period and which will not. The point where the demand curve meets the system marginal cost curve also determines the market-clearing price, which in a system with no transmission constraints is paid to every dispatched generator. This auction structure is known as the uniform-price auction. When transmission constraints are binding, generators are paid the LMP in their portion of the transmission grid, which incorporates both the market-clearing price and the congestion costs associated with the transmission constraints. Thus, generators may not get exactly the market-clearing price, but under the LMP pricing system and the uniform-price auction used in RTO markets, inexpensive generators likely earn more than their average costs.

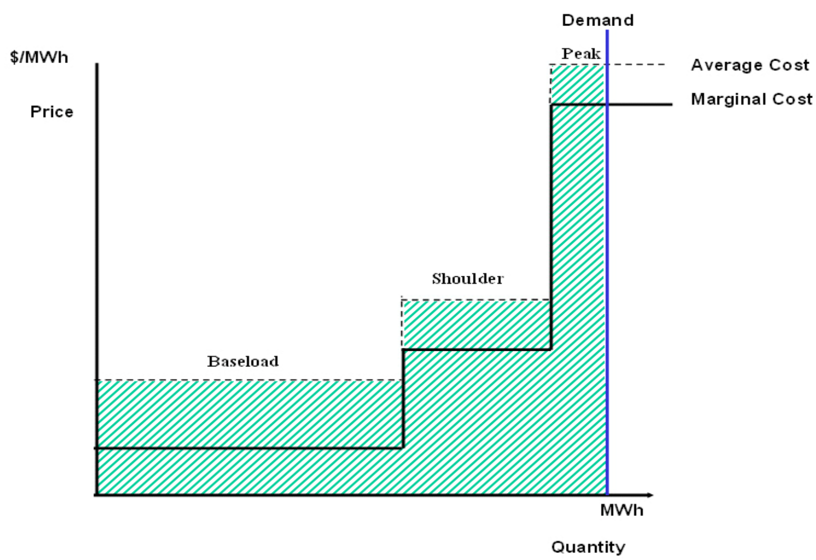

Figure 13: Under regulation, compensation for generators was based on the average cost of each plant. In this example, there are baseload, shoulder, and peaking plants. The total generation cost of serving the load is given by the shaded area under the average cost curve. Source: L. Lave, J. Apt, & S. Blumsack, *Rethinking Electricity Deregulation*, 17 ELECTRICITY JOURNAL 11 (2004).

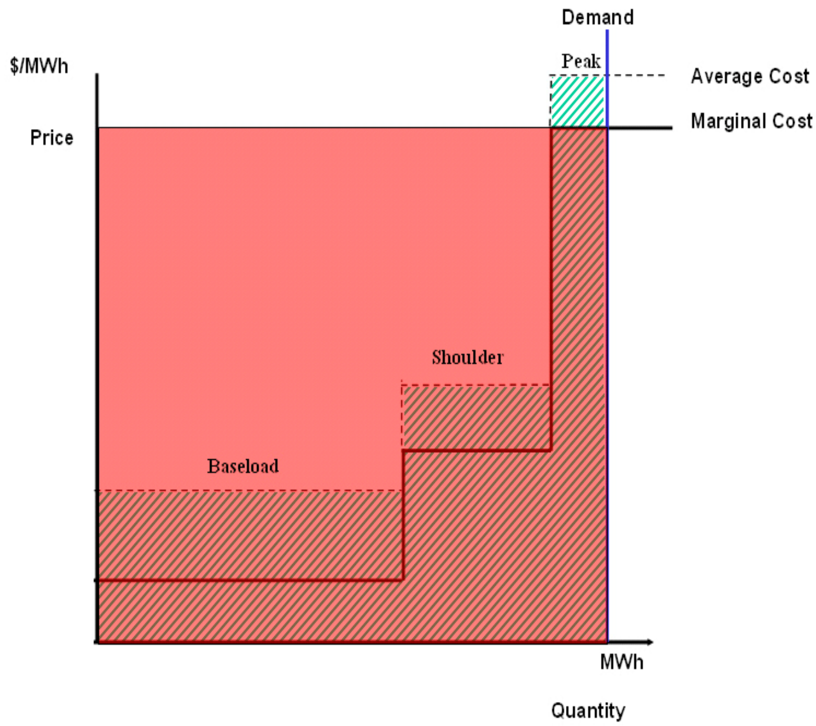

Figure 14: In the uniform-price auction used in U.S. RTO markets, all dispatched generation is paid based on the bid of the marginal generator (in this case, the peaking unit). The total generation cost of serving the load is equal to the amount of load served times the market-clearing price (the shaded box). Source: L. Lave, J. Apt, & S. Blumsack, *Rethinking Elec. Deregulation*, 17 ELECTRICITY JOURNAL 11 (2004).

A distributional effect of this auction structure is that during peak periods, generation in a high-cost area can set the price in a low-cost area. For example, less than two percent of the generation in Pennsylvania is from natural gas, and ninety percent of the power produced is from coal and nuclear power. However, natural gas sets the price in PJM during sixty percent of the peak hours.[76]

The uniform-price auction has been criticized for effectively overpaying baseload generation and underpaying peak generation.[77] Baseload generators, which are usually coal and nuclear units, can get paid based on the marginal cost of the marginal generator; particularly during peak periods the marginal system cost can be much larger than the marginal cost of baseload generation. The problem with compensating peaking generation is particularly acute. If the market is competitive, either by design or through the actions of the RTO market monitors, then the 'peakers' will only recoup their marginal costs, and not their

76. *See* 2005 STATE OF THE MARKET REPORT, PJM INTERCONNECTION (2006), *available at* http://www.pjm.com/markets/market-monitor/som.html.

77. *Rethinking Deregulation, supra* note 27.

capital costs. Since peaking units depend on high prices in a small number of hours to recover their capital costs, the pricing structure used in RTO markets discourages the construction of peaking generation. The problem faced by peaking units is partially economic and partially political. In the absence of active market monitors, prices during peak hours would rise to very high levels, reflecting scarcity-related market power. Particularly after California's power crisis, RTOs have been hesitant to allow market prices to get too high, and have replaced high energy prices with secondary capacity payments or other out-of-market mechanisms to ensure that peaking units are made whole through participation in the market.[78]

Alternatives to the uniform-price auction have been proposed. One suggestion is to keep the basic RTO auction format, but simply pay each dispatched generator their bid instead of the bid of the marginal generator. This pay-as-bid auction structure is currently used in the United Kingdom. However, theory and experimental evidence suggest that the result from a pay-as-bid auction should not be significantly different from a uniform-price auction. Generators have a good deal of information going into the auction; in particular they know the demand forecasts of the RTO. Thus, a baseload generator who has a reasonable expectation that demand will be high enough to make a shoulder or peaking plant the marginal unit will simply raise their bid. As long as they bid lower than the marginal unit, they will be dispatched by the RTO. Giuliano Federico and David Rahman have demonstrated this in theory, confirmed by experiments with human subjects.[79] A Blue-Ribbon Panel convened by the California Power Exchange in 2000 found that there would be no significant differences in market prices from switching to the pay-as-bid model.[80]

Another suggestion has been to harness the power of price-responsive load by allowing load to actively bid into the market. The original RTO auction model was focused entirely on the supply side; the RTO assumed that consumers were completely price-inelastic and used a vertical demand curve (as in Figures 13 and 14) to determine the market-clearing price and generation dispatch. Experimental evidence using both computerized bidding agents and human subjects has demonstrated that active demand bidding can lead to lower prices and a less costly way to mitigate market power.[81] Figure 15, from Talukdar *et.*

78. The structure and justification for capacity markets has been a contentious and highly debated topic. Often times, they have not been very competitive. *See* 2005 STATE OF THE MARKET REPORT, PJM INTERCONNECTION (2006), *available at* http://www.pjm.com/markets/market-monitor/som.html. Paul Joskow & Jean Tirole, *Reliability and Competitive Electricity Markets*, RAND JOURNAL OF ECONOMICS (forthcoming), defend capacity markets on economic grounds as a "second-best" solution in the face of political constraints on scarcity pricing. William Hogan and Shmuel Oren have each proposed an alternative market structure that would do away with capacity markets while still maintaining the economic viability of peaking generation. *See* WILLIAM HOGAN, CENTER FOR BUSINESS AND GOV'T, HARVARD UNIV., AN ENERGY-ONLY MARKET DESIGN (2005), *available at* www.whogan.com; *and* Shmuel Oren, Ensuring Generation Adequacy Through Centrally Procured Call Options Obligations, Proceeding of the IEEE PES Annual Meeting (2005).

79. Giulio Federico & David Rahman, *Bidding in an Elec. Pay-as-Bid Auction*, 24 JOURNAL OF REGULATORY ECONOMICS 175 (2003); Stephen Rassenti, Vernon Smith, & Bart Wilson, *Discriminatory Price Auctions in Elec. Mkts.: Low Volatility at the Expense of High Price Levels*, 23 JOURNAL OF REGULATORY ECONOMICS 109 (2003).

80. ALFREED E. KAHN, PETER C. CRAMPTON, & ROBERT H. PORTER, POWER SYS. ENG'G RESEARCH CENTER, PRICING IN THE CAL. POWER EXCHANGE ELEC. MKT.: SHOULD CAL. SWITCH FROM UNIFORM PRICING TO PAY-AS-BID PRICING (2001).

81. Talukdar, *supra* note 42. The authors point out that since the auction is repeated so often, with essentially the same group of participants each time, market players can learn each others's strategies and make adjustments to maximize joint profits without any communication whatsoever.

al.[82] demonstrates the result using computer simulations. The top line shows the market price in an auction where only the generators are active bidders. Even though the generators have a simple bidding strategy and are nowhere near as sophisticated as actual power traders, they are able to raise the price in a very short amount of time. The bottom line shows the market price in an auction where both generators and consumers bid into the auction.

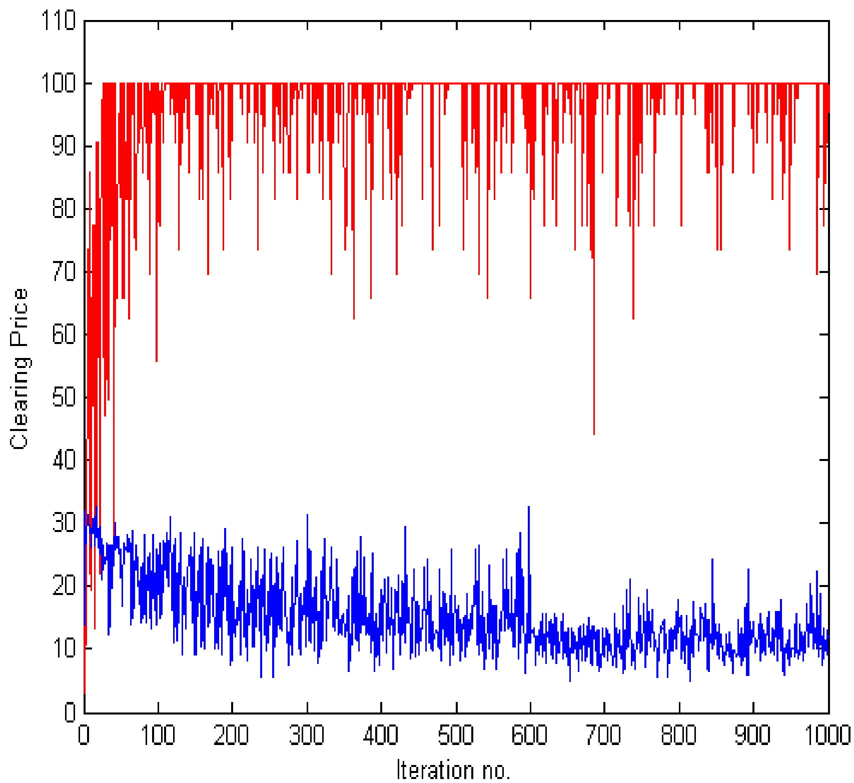

Figure 15: Active demand-side bidding can effectively mitigate market power. The top line represents the prices from electricity market simulations where only generators are allowed to bid into the auction. The bottom line represents prices when both generators and consumers are allowed to bid into the auction. Source: S. TALUKDAR, T. MOUNT, S. OREN, & R. THOMAS, POWER SYS. ENG'G RESEARCH CENTER, SOFTWARE AGENTS FOR MKT. DESIGN AND ANALYSIS (2005).

RTOs have not completely ignored the demand side, although they are not nearly as integrated into the spot market as is the supply side. Demand response is largely viewed by the RTOs as one in a suite of ancillary services that can be provided to the grid. Individual customers can bid demand response into PJM, for example, but the costs of doing so are prohibitive for all but large and sophisticated loads. Another barrier to entry on the demand side is that load-reduction resources cannot be bid into the market if they are below a certain

82. *Id.*

size.[83] Thus, demand-response activity at the level of individual customers (particularly small customers) has been low, although a number of load aggregators participate in demand-side markets within RTO footprints.[84]

Along with the auction structure, the move towards regional grid integration has been accompanied by seemingly unrelated policy decisions aimed at disrupting the vertically-integrated utility structure. Several states, including the PJM states and California, forced their formerly integrated utilities to divest most or all of their generation in exchange for generous stranded cost retirement allowances. Utility plants were generally sold off to non-utility generating companies as happened in California; utilities in other areas simply created an unregulated generation subsidiary with limited ability to fall back financially on the parent company. At first, this new merchant generation sector was quite active, with approximately 55 GW of new (mostly gas-fired) generation built between the mid 1990s and the early 2000s when gas prices started to rise.[85]

The move to encourage the merchant generation sector may have increased competition in nascent centralized electric energy spot markets, but it has had the side effect of increasing risk in a highly capital-intensive industry. Prior to restructuring, utility debt was considered virtually risk-free since the rate of return was guaranteed by the public utility commission, and the costs of new construction could be passed on to ratepayers. Under restructuring, new merchant generation is entirely dependent on the market for its returns. In the parlance of venture capital, electric generation investment has moved from being a "system" investment under regulation to being a "project" investment under restructuring. The necessity of project financing for new generation, combined with market and regulatory uncertainty (particularly following the Enron scandal), has increased the hurdle rate from ten percent to fifteen percent or twenty percent.[86] For a large coal plant roughly two-thirds of the variable costs represent capital costs. A doubling of the cost of capital could increase the variable cost of coal-fired generation by between one and five cents per kilowatt-hour.[87]

In the regulated era, bad investments or poor management on the part of the utility represented risks that were often borne by the ratepayers. Probably the best example is nuclear power; utilities did not realize that constructing and operating a large nuclear unit would be far more complex and difficult than operating a similarly-sized coal unit. Cost overruns and poor operation were commonplace,[88] and public utility commissions generally allowed the costs to be passed on to ratepayers. Divestiture policies under restructuring have been

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83. In the NYISO, for example, there is a one megawatt limit, as reported in R. Walawalkar, J. Apt, & R. Mancini, *Economics of Elec. Energy Storage for Energy Arbitrage and Regulation in New York*, ENERGY POLICY (forthcoming). These limits are currently being re-evaluated by many of the RTOs.

84. There is a natural question as to the possibilities for demand response. System marginal cost curves are typically fairly flat over a large range of demands, and then increase rapidly as the capacity constraint is approached. Thus, most of the gains in demand response would come in the highest-demand hours. It is therefore a reasonable question as to what the gains would be from providing demand-response incentives to all customers, as opposed to policies focused on the largest users in the system.

85. Joskow, *supra* note 28; *A Cautionary Tale*, *supra* note 28.

86. G. KRELLENSTEIN, CARNEGIE-MELLON, TRANSMISSION FINANCING (2005), a*vailable at* http://www.ece.cmu.edu/~electriconf/old2004/. An additional factor increasing risk may be the use of debt by merchant companies.

87. *Lessons*, *supra* note 27.

88. The most striking example involves the Washington Public Power Supply System (with the apt acronym of WPPSS). The cost overruns on the WPPSS nuclear units were so high that the state was forced to default on its bond obligations. At the time it was the largest municipal default in history.

aimed at a reallocation of the capital investment risks. The emergence of non-utility or merchant generation has shifted the risk-reward calculus to shareholders in merchant companies, as opposed to ratepayers or taxpayers. When natural gas prices began rising dramatically in the years following the California power crisis, the merchant plants (which mostly ran on gas) couldn't compete with lower-cost coal and nuclear. The result has been a slate of underperforming assets, and merchant debt has essentially been downgraded to junk status. Thus, shareholders in merchant companies have suffered the most, but there have been some spillover effects. Even privately-owned utility debt has fallen below its historic levels.[89]

D. Environmental Effects

One benefit of the introduction of regional power markets has been to increase the utilization of inexpensive generation sources, as shown in Figure 7. While this has lowered the generation cost (but not necessarily the price, as discussed above), to the extent that these low-cost resources are fossil units, there will be an associated cost in the form of increased emissions of SO_2, NO_x, and CO_2. Steven Holland and Erin Mansur have demonstrated that if consumers begin responding to the short-run pricing signals from regional power markets, the result will be to increase emissions of these pollutants as consumers switch from cleaner peaking power (natural gas) to dirtier base load power (coal).[90]

The Holland and Mansur analysis is insightful and counterintuitive, but the issue of environmental impacts is not limited to the extent of real-time electricity pricing. Integrating coal-fired generation into a system with a significant amount of high-cost baseload generation will favor coal in the dispatch order. The increased capacity factor of coal will be associated with higher emissions. Specifically, data from the EPA's E-Grid database of power plants suggests that the increased capacity factor of coal, from an average of sixty-three percent to sixty-six percent since 1998, has been associated with approximately a five percent increase in major pollutants such as SO_2, NO_x, CO_2, and mercury.[91] This has been a particularly important issue in the Mid-Atlantic RTOs, which are downwind from the major coal generation centers in the Midwest. Pittsburgh currently has the worst fine-particulate pollution of any major United States city, due in large part to the output of coal-fired power plants in Western Pennsylvania and Ohio.[92]

E. Seams Issues and Externalities

The borders between electricity control areas are known as seams. In AC power networks, where the physical flow of energy is determined by Kirchoff's and Ohm's Laws, rather than by economic deals and contracts, the seams are

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89. Joskow, *supra* note 28; *A Cautionary Tale*, *supra* note 28. The Brattle Group reports that the number of electric-sector companies with BBB+ or better credit ratings has been cut nearly in half (from seventy-five to forty) since the 1990's. *See* G. BASHEDA, M. CHUPKA, P. FOX-PENNER, J. PFEIFENBERGER, & A. SCHUMACHER, THE EDISON FOUNDATION, WHY ARE ELEC. PRICES INCREASING? AN INDUSTRY-WIDE PERSPECTIVE 79-82 (2006). Public power (municipal and federal systems) has not fared nearly as poorly.

90. Stephen Holland and Erin Mansur, *The Short-Run Effects of Time-Varying Prices in Competitive Electricity Markets*, 27 ENERGY JOURNAL 127 (2006).

91. Emissions rates from the 2000 EPA E-Grid database were applied to output from coal plants for the year 2000 onwards. Thus, the data for 2001 to 2005 are estimates. New Source Performance Standards and the Clean Interstate Air Act dictate that new and existing coal plants will eventually have to install equipment to control a number of different pollutants.

92. Penn Environment, Plagued by Pollution (2006), *available at* http://www.pennenvironment.org.

largely artificial administrative boundaries, and do not always correspond to natural breaks in the electric grid. The electric network is essentially a single system of coupled components, so what happens in one part of the grid will likely have effects in the rest of the grid. Depending on the geographic extent of electric grid integration, and the institutions established, changes in flow patterns or market rules can have physical and economic effects on other systems. Two of these seams issues are discussed here. The first is that regional grid integration may have loop-flow effects that increase congestion on neighboring systems. The second is that administrative seams in the form of different market rules may restrict beneficial cross-border trading activity.

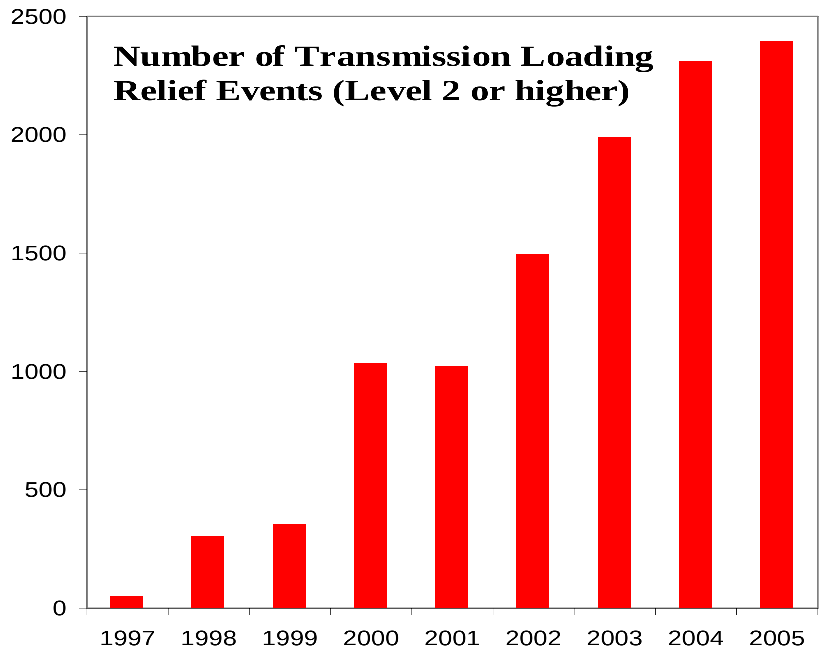

Figure 16: Number of transmission load relief events (level 2 or higher). Source: NERC.

According to Ohm's Law, electric power travels along all parallel paths, apportioned according to the electrical resistance of each path. Sometimes these parallel paths can form loops, where power injected at one point in the grid is essentially transferred throughout the grid, only to be consumed at the point of injection. These are referred to as loop flows. Figures 5, 6, and 12 suggest that the establishment of centralized regional spot markets has encouraged more transactions over longer geographic and electrical distances, representing another use of the transmission grid other than its intended purpose of serving the native load of vertically-integrated utilities. The increased number of wheeling transactions, as indicated in Figure 6, plus the associated parallel and loop flows, have increased congestion throughout the Eastern Interconnect. Figure 12 shows these costs for PJM; in an RTO setting, congestion is normally handled with a market mechanism. In traditionally-organized systems, congestion is managed through a set of protocols known as Transmission Loading Relief (TLR).[93] The TLR protocol allows transmission owners to physically restrict access to the grid in the case of congestion or reliability concerns. The exact rationing order

93. The exact specification of TLRs is determined by NERC in its Reliability Standard IRO-006-1.

depends on the different types of transmission service purchased from the transmission owner. The incidence of TLRs of at least level two (when non-firm transactions are curtailed) has increased dramatically since the onset of restructuring and the establishment of regional power markets, as shown in Figure 16. While it is difficult to place an exact monetary value on these TLRs (similar to how congestion is valued in PJM), they do represent a cost associated with regional grid and market integration.

The markets run in RTO systems and the markets run in traditionally-organized systems are not considered to be compatible.[94] In traditionally-organized markets, bilateral transactions are tagged with a source, a sink, and a contract path (which may or may not bear any resemblance to the physical path taken by the power under the bilateral transaction). Firmness of the contract is determined by the level of physical transmission service purchased. In RTO markets, generation is dispatched centrally; physical transmission access does not have to be purchased, but market participants are responsible for financial congestion charges. Bilateral transactions are submitted as bulk injections and withdrawals to the RTO and are effectively settled against LMPs. Thus, it can be difficult for RTO grid operators to associate incidences of congestion with specific transactions. This is most problematic at the interface between the RTO territory and a traditionally-organized control area. In the event of congestion at the interface, the responsibility for curtailment is not clear. Market incompatibilities such as these have also been observed between RTOs. One analysis of the seams between PJM and NYISO estimated that less than half of mutually-beneficial cross-border transactions were taking place.[95]

Seams issues in the Eastern Interconnect have been handled through a series of multilateral agreements between RTOs and traditionally-organized utility control areas. MISO, for example, has a number of seams agreements with PJM, TVA, MAPP, and SPP that provide detailed data-sharing arrangements and procedures for handling congestion and reliability issues at the interface. These agreements were either in place or nearly in place by the time MISO's market opened in 2005.[96] When PJM's market opened, it had a number of generic protocols in place to handle technical seams issues, such as interchange capability.[97] Other seams issues have been handled as they arose.[98] The redesign of the California ISO market following the power crisis has caused a great deal of controversy with its apparent inattention to seams issues affecting the remainder of the Western Interconnect.[99]

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94. MISO-SPP Congestion Management Process, http://www.midwestmarket.org/publish/Document/7be606_10b7aacd66e_-7cef0a48324a?rev=1, at section 1.1.1.

95. Norman Mah, *Observed Impediments to Trade in PJM and S.E. New York* (May 5, 2006), http://www.nyiso.com/public/webdocs/committees/bic_spwg/meeting_materials/2006-0505/ce_pjm_nyc_proxy_bus_spwg.pdf.

96. *See* JOINT RELIABILITY COORDINATION AGREEMENT AMONG AND BETWEEN MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, PJM INTERCONNECTION, AND TENNESSEE VALLEY AUTHORITY (April 22, 2005); *see also* JAMES TORGERSON & NICHOLAS BROWN, MISO-SPP CONGESTION MGMT. PROCESS (Jan. 11, 2006).

97. *See* PJM TRANSMISSION SERVICES BUSINESS PRACTICE MANUAL (Oct. 25, 2006); *see also* PJM OPEN ACCESS TRANSMISSION TARIFF (Jan. 1, 2007).

98. These have generally been handled through the Northeast Seams Resolution between PJM, NYISO, and ISO-NE. A history of seams resolution activities is *available at* http://www.pjm.com/documents/seams.html.

99. The CAISO's Market Redesign and Technology Upgrade (MRTU) apparently makes no mention of seams issues. *See* California Ind. Sys. Operator Corp., Docket No. ER06-615-000 (FERC Dec. 20, 2006).

VI. SUMMARY AND DISCUSSION

The metrics currently used to evaluate the effects of regional grid integration are incomplete and not objective. Analyses using identical data have reached different conclusions; an example is the retail price papers by Joskow, Apt, and Taber.. A broad assessment of restructuring would focus on the following metrics:

- *Wholesale markets*: Regional grid integration has created wholesale markets that are highly liquid. The energy markets generally behave competitively, but without the intervention of market monitors would likely behave rather uncompetitively;
- *Generation efficiency*: Joint regional dispatch has increased the efficiencies of low-cost baseload units such as nuclear power and coal. The uniform-price auction used in RTO markets has encouraged these generation resources to operate more efficiently.
- *Retail prices*: Great disagreement exists as to whether restructuring has been associated with decreases in retail prices. Sources of conflict include the modeling of regulatory interventions (rate caps and freezes) and the restructuring process itself. There is not a single agreed-upon framework for evaluating the effects on retail prices. Nearly everyone agrees that some kind of counterfactual analysis is required, but not on what it should look like. The existing evidence suggests that for better or worse, the effects on retail prices have thus far been reasonably small. As more states complete the transition into full retail competition, larger price increases are becoming more common.

This paper has suggested that the following issues are also significant:

- *The direct costs of RTO operation*: These should certainly be incorporated into any cost-benefit analysis of regional grid integration, although with the possible exception of start-up costs, the data suggest that these are reasonably small;
- *Regional complementarities*: Systems with highly coincident demands will require a much more robust transmission infrastructure to support competition and the benefits of regional dispatch. Non-coincident demand (such as the seasonal complementarities in the West) can provide benefits to regional integration without massive investments in transmission upgrades;
- *Market structures*: Even when highly competitive, the auction structure favored by RTOs inherently increases costs by paying all dispatched generation based on the cost or bid of the generator on the margin. A related issue is that merchant generation in a market environment has increased risk for investment in generation and transmission;
- *Demand response*: High market prices can act as a powerful conservation and demand-response tool, particularly for the largest users;
- *Environmental effects*: Regional dispatch inevitably uses lower-cost resources more intensively. This has the positive effect of lowering prices in high-cost areas, but to the extent that baseload resources are fossil-fuel units (not hydro or nuclear), there will be increased environmental costs;
- *Seams issues*: Control area boundaries are artificial, in that they are administratively and historically determined, whereas power flows throughout an interconnected network are determined by the laws of physics. Regional grid integration fundamentally alters the pattern of flows through the integrated network and surrounding systems. This does not

necessarily have to bring harm to the integrated system or neighboring systems, but the increase in congestion and TLRs suggests that there have been significant costs associated with the move towards regional power markets.

This paper does not attempt to present a thorough cost-benefit analysis of all RTOs based on the above metrics. Some of the relevant variables (particularly the effects associated with TLRs) are difficult to monetize and thus directly aggregate with more easily-valued benefits and costs such as effects on retail prices. The metrics in this paper suggest that the value of regional integration in the Eastern RTOs such as PJM has probably been hampered by the persistence of transmission constraints that prevent joint dispatch from exploiting regional complementarities. In the specific case of PJM, this has been made more acute by the expansion of the PJM footprint, which has incorporated a large amount of inexpensive coal generation into the dispatch order, but without sufficient supporting transmission. The ESAI report, for example, shows that prices in moderately congested areas of PJM have gone down since PJM's expansion, while prices in formerly un-congested areas have gone up. Prices in highly congested areas (the area surrounding Philadelphia, New Jersey, and the Delmarva Peninsula) appear not to have declined.[100] Until the right investments can be made, PJM as it currently exists may be too large. California and the Pacific Northwest enjoy a different kind of complementarity, in that their seasonal demands are anti-correlated. Even without large amounts of new transmission, there should be large gains from Western regional dispatch; this dispatch would probably mirror the historic seasonal energy exchanges between California and Northwest utilities. However, the market structure of the CAISO is radically different from the rest of the West and has ultimately balkanized the Interconnection. Unless the interconnection issues between CAISO and the rest of the West can be resolved, California's RTO will probably be too small to yield significant benefits to consumers or the system.

VII. CONCLUSIONS

Ten years have passed since the process of electricity restructuring got underway in the United States. Whether the experiment has been successful is a highly controversial and hotly-debated subject, as are the next steps that policymakers should take. If restructuring and RTOs have been successful, then perhaps other regions should take the lead of PJM and the Northeastern United States. If restructuring has not been a success, then policymakers face a series of painful choices about whether further reforms should be enacted, or whether the entire system should be dismantled.

Successful design artifacts can only arise out of a good problem formulation. That is, the goals of the artifact must be precisely enumerated, a set of performance metrics must be defined, and most importantly, there must be a good verification process for ensuring that the artifact meets the specified goals. If electricity restructuring in the United States fails, it is not because of Enron or any other group of stakeholders, but rather because the markets and institutions emerged from a poor formulation of the problem that restructuring was supposed to solve. California's doomed market was designed without sufficient input from experienced engineers; by default this yielded an incomplete set of performance metrics and a verification process somewhere between terrible and

100. ESAI, *supra* note 34, at 56-57.

nonexistent. The current controversy over regional integration in markets and electric grids stems from a lack of clarity regarding the policy goals underlying restructuring. Whether lower prices for consumers, open access to transmission, or the promotion of markets itself is the ultimate goal is far from clear. Just as problematic as the lack of well-defined policy goals is the lack of well-defined metrics for verifying whether the policy goals have been met. Good metrics are objective, thorough, consensual, and are reflected in policy decisions.