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A Review of Recent RTO Benefit-Cost Studies: Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies

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Abstract

During the past three years, government and private organizations have issued more than a dozen studies of the benefits and costs of Regional Transmission Organizations (RTOs). Most of these studies have focused on benefits that can be readily estimated using traditional production-cost simulation techniques, which compare the cost of centralized dispatch under an RTO to dispatch in the absence of an RTO, and on costs associated with RTO start-up and operation. Taken as a whole, it is difficult to draw definitive conclusions from these studies because they have not examined potentially much larger benefits (and costs) resulting from the impacts of RTOs on reliability management, generation and transmission investment and operation, and wholesale electricity market operation.

This report: 1) Describes the history of benefit-cost analysis of FERC electricity restructuring policies; 2) Reviews current practice by analyzing 11 RTO benefit-cost studies that were published between 2002 and 2004 and makes recommendations to improve the documentation of data and methods and the presentation of findings in future studies that focus primarily on estimating short-run economic impacts; and 3) Reviews important impacts of FERC policies that have been overlooked or incompletely treated by recent RTO benefit-cost studies and the challenges to crafting more comprehensive assessments of these impacts based on actual performance, including impacts on reliability management, generation and transmission investment and operation, and wholesale electricity market operation.

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Acronyms

AEP	American Electric Power
B	billion
Btu	British Thermal Unit
CAISO	California Independent System Operator
CERA	Cambridge Energy Research Associates
CRA	Charles Rivers Associates
DOE	U.S. Department of Energy
DVP	Dominion Virginia Power
EA	Environmental Assessment
EIA	Energy Information Administration
EIS	Environmental Impact Statement
ESAI	Energy Security Analysis, Inc.
FERC	Federal Energy Regulatory Commission
FTR	financial transmission right
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kW	kilowatt
kWh	kilowatt hour
LMP	locational marginal price
M	million
MISO	Midwest Independent System Operator
MWh	megawatt hour
NERC	North American Electric Reliability Council
NERTO	Northeastern RTO
NOPR	Notice of Proposed Rulemaking
NIPA	National Income and Product Account
NPV	net present value
NYISO	New York Independent System Operator
O&M	operations and maintenance
PJM	Pennsylvania-New Jersey-Maryland Interconnection
RTO	Regional Transmission Organization
SAIC	Science Applications International Corporation
SMD	Standard Market Design
SPP	Southwest Power Pool
TCA	Tabors, Caramanis, and Associates

Executive Summary

During the past three years, government and private organizations have issued more than a dozen studies of the benefits and costs of Regional Transmission Organizations (RTOs). Most of these studies have focused on benefits that can be readily estimated using traditional production-cost simulation techniques, which compare the cost of centralized dispatch under an RTO to dispatch in the absence of an RTO, and on costs associated with RTO start-up and operation. Taken as a whole, it is difficult to draw definitive conclusions from these studies because they have not examined potentially much larger benefits (and costs) resulting from the impacts of RTOs on reliability management, generation and transmission investment and operation, and wholesale electricity market operation.

Recent studies should not be criticized for failing to consider these additional areas of impact, because for the most part neither data nor methods yet exist on which to base definitive analyses. At the same time, it is important to understand that we are now in a period of transition from analyses that were necessarily prospective and hypothetical to a period in which analyses can be retrospective and based on empirical evidence. The latter approach should become the standard for assessing the impacts of Federal Energy Regulatory Commission's (FERC) policies. The primary objective is not simply to improve individual future RTO benefit-cost studies but to establish a more robust empirical basis for ongoing assessment of the electricity industry's evolution.

To aid in improving future studies of the benefits and costs of FERC's electricity restructuring policies, this report reviews current practices in RTO benefit-cost analysis. The review is motivated by the following considerations:

1. FERC's policies regarding RTOs have wide-ranging impacts on the production, transmission, and consumption of electricity. Public-policy makers want to know the direction and size of these impacts.
2. The data and the methodologies needed to inform policy makers are incomplete. Some impacts can be estimated at this time, others will require some time to assess, and some may never be estimated quantitatively. The approaches and data used in recent studies enable us to begin to identify and prioritize needed improvements in data and methods.

This report is organized as follows:

Section 1 outlines the scope and purposes of the analysis.

Section 2 describes the history of benefit-cost analysis of FERC electricity restructuring policies. We review the Environmental Impact Statement (EIS) prepared for FERC Order 888 in 1996 and the Environmental Assessment (EA) prepared as part of Order 2000 in 1999, both of which pre-dated FERC's RTO policies.

Table EX-1. Benefits and Costs Examined Quantitatively by RTO Studies

Author. Year. Study Title	**Impacts Examined Quantitatively**							
	Short-Run Dispatch Cost Savings	RTO Start-Up Costs	RTO Oper-ating Costs.	Cost Impacts on Others	Reliability Mgmt. Costs	Relia-bility Perfor mance	G&T Operating Efficiency & Investment	Wholesale Market Impacts
PJM. 2002. *Northeast Regional RTO Proposal Analysis of Impact on Spot Energy Prices*.	X						Assumed	
ICF. 2002. *Economic Assessment of RTO Policy*.	X	X					Assumed	Demand Response
TCA. 2002. *RTO West Benefit/Cost Study*.	X	X	X		Operating Reserves			Market Power
ESAI. 2002. *Impact of the Creation of a Single MISO-PJM-SPP Power Market*.	X							Demand Response
ISO-NE/NYISO. 2002. *Economic and Reliability Assessment of a Northeastern RTO*.	X	X	X		Operating Reserves			
CRA. 2002. *The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast*.	X	X	X	No net cost savings				
DOE. 2003. *Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design*.	X	X	X				Assumed	Demand Response
CERA. 2003. *Economic Assessment of American Electric Power's Participation in PJM*.	X							
SAIC. 2004. *The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets*.	X	X	X					
CRA. 2004. *The Benefits and Costs of Dominion Virginia Power Joining PJM*.	X	X	X					
Henwood. 2004. *Study of Costs, Benefits and Alternatives to Grid West*.	X	X	X		Operating Reserves			

The EIS broadly conceptualizes the expected economic and reliability impacts of Order 888 and presents modest quantitative findings on an equal footing with necessarily qualitative findings based on analogies drawn from other industries. We express the EIS's initial description
of potential impacts using a standard economic framework for assessing benefits and costs and begin to outline some of the challenges involved in estimating these impacts in practice.

Section 3 reviews current practice by analyzing 11 RTO benefit-cost studies that were published between 2002 and 2004. See Table EX-1.[1] As a group, the studies document the evolution of the policy dialogue regarding RTO formation. Close reading of the findings reveals the modest size and narrow range of expected benefits and costs analyzed to date.

In view of the small size and narrow ranges between the quantitative results we observe, we pay special attention to the methods and data used by the studies. We find that that the underlying uncertainties in the data and methods used in these studies are large in comparison to the RTO impacts estimated in the studies. Thus, it is necessary to examine closely the study methods and data used if we are to gauge accurately the impacts of FERC's policies regarding RTOs.

In terms of methods, the studies primarily consider the tradeoff between <u>benefits</u> in the form of short-run production-cost efficiencies and <u>costs</u> for the start-up and operation of an RTO. We organize our review around the following topics:

1. Specification of baseline case and of policy changes resulting from RTOs,
2. Scope of benefits-costs considered,
3. Production-cost simulation methods used for analysis, and
4. Costs of RTOs vs. cost impacts on other market participants.

We recommend a number of improvements in documentation of data and methods used and in the presentation of findings for future RTO benefit-cost studies designed to focus primarily on estimating these short-run economic impacts. See Table EX-2.

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[1] More than 11 benefit-cost studies were conducted during this period; and additional studies have been published since this research was initiated. We believe the 11 studies we review are broadly representative of current practices, but we do not suggest that our findings extend to all studies.

Table EX-2. Recommendations for Improving RTO Benefit-Cost Studies Focused on Short-term Economic Efficiency Impacts

Study Element	**Recommendations**
Baseline and Policy	Clearly articulate assumed base-case conditions and changes assumed for the policy (RTO) case(s). Provide rationale for assumed changes in policy case(s)
Benefit-Cost Perspectives	Present and identify benefits and costs inclusively from a wide variety of perspectives. Clarify differences between transfers among market participants (and articulate the mechanisms by which transfers take place) and net changes in total societal costs.
Long-Term Contracts	Describe treatment of long-term contracts and "grandfathered" transmission agreements.
Hurdle Rates	Discuss (and present numerical results from application of) calibration standard and other "tuning" mechanisms (e.g., transmission-path rating assumptions), including influence of these choices on policy in question. Provide rationale for hurdle-rate adjustment in policy case. Discuss treatment of hurdle-rate changes in various benefit-cost perspectives.
Transmission Network	Describe representation of transmission network capabilities by study tools. Discuss implications of choice of study tool (and its representation of transmission network) on findings, including likely biases or significance of uncertainty that is introduced by this choice .
Generator Offers	Conduct sensitivity studies that directly account for possibility and impact of market power abuse by generators (e.g., adding a dynamic price premium on top of variable production costs for generators in load pockets).
Cost of FERC Policies	Discuss functional and empirical basis for RTO cost estimates. Discuss cost impacts on all stakeholders.

Section 4 reviews important impacts of FERC policies that have been overlooked or incompletely treated by recent RTO benefit-cost studies, including impacts on reliability management, generation and transmission investment and operation, and wholesale electricity market operation. These impacts may be of greater significance than those considered to date. Failure to consider these additional impacts leads to an incomplete picture of the effects of FERC's policies.

As noted earlier, we are now in a period of transition from analyses that were necessarily prospective and hypothetical to a period in which analyses can be retrospective and based on empirical evidence. Accordingly, in Section 4, we focus on identifying the challenges to conducting more comprehensive assessments of RTO impacts based on actual performance. See Table EX-3. Three types of impacts, in particular, need investigation and analysis:

<u>Reliability Management</u>: Formation of an RTO might affect reliability management in two key ways: 1) The cost of managing reliability in real time may be reduced as result of economies of scale that an RTO could capture; this aspect of RTO operation has been addressed to a limited degree by some recent studies. 2) The quality and scope of reliability management within and among regions might change under an RTO; this aspect has only been mentioned by recent studies.

Addressing reliability management impacts requires development of reliability metrics and collection of relevant data over time. A key challenge is that significant outages are comparatively rare events. The recent revisions to North American Electric Reliability Council (NERC) standards will facilitate this work. Data are needed from all organizations that have real-time reliability management responsibilities, not just RTOs and ISOs. Collecting such data from the full range of such organizations will enhance our understanding of reliability performance in general.

<u>Generation and Transmission Investment and Operation</u>: The EIS and EA for the FERC's orders mentioned above envisioned significant long-run changes in generation and transmission investment, including the introduction of advanced technologies, as well as enhancements/improvements to the efficiency of the assets themselves (e.g., new generation entry and investment, generation efficiency and availability, and transmission capability). These impacts have generally not been addressed in recent benefit-cost studies.

Recent appearance of academic analyses - conducted independent of formal RTO benefit-cost studies - are noteworthy for explicitly relying on empirical information and for rigorously controlling for many influences that could otherwise skew their findings. This new research also illustrates the difficulty of trying to assess the impacts of individual FERC policies. The difficulty of separating the effects of interrelated policies is an inherent limiting factor in any study of the effects of FERC's orders.

We recommend that future studies focus on systematic analysis of empirical data on generation and transmission investment and operation. Special attention should be paid to the role of RTOs, ISOs, and other regional entities as vehicles for the regional transmission planning that is an essential enabler for these investments. Existing Energy Information Administration (EIA) and FERC data-collection activities should be reviewed and revised with the above objectives in mind.[2] Topics to address on FERC Form 1 include: 1) Consistently separating transmission from distribution, and identifying costs, revenues, and net capital stock and investment using the National Income and Product Account (NIPA) definitions of investment; 2) Specifically identifying investments in the high-voltage grid, including related computation, communications, and metering devices.

Table EX-3 Recommendations for Additional Topics That Should be Included in Future RTO Benefit-Cost Studies

Study Elements	**Recommended Areas of Focus**
Reliability Management	The total cost of managing reliability within and among regions under an RTO. The quality and scope of reliability management activities within and among regions under an RTO, including establishing a baseline.
Generation and Transmission Investment and Operation	Generation and transmission investment, including role of regional planning. Generation operating efficiency (heat rate, fixed and variable O&C costs) and availability. Transmission capability, congestion management.
Wholesale Electricity Market Operation	New entry. Generator access and service denial. Cost and quality of transmission service available to generators. Cost of congestion, volume and frequency of curtailment, flow of power (trade) across regions, and the price differentials that correspond to these factors. Role and impact of demand response.

[2] During the final stages of preparation of this report, FERC issued order 668, Accounting and Financial Reporting for Public Utilities Including RTOs, which addresses this recommendation (FERC 2005).

<u>Wholesale Electricity Market Operation</u>: Although formation of competitive wholesale electricity markets plays a central role in recent FERC policies, especially policies on RTOs, the studies we reviewed pay little or no attention to impacts of these markets, aside from impacts associated with enabling more efficient regional dispatch. This omission is a major shortcoming in these studies.

Many analysts believe that formal markets, because of their greater transparency, are essential to enable and support the evolution of better business strategies for managing the financial risks associated with future investments in generation and transmission capacity. These researchers also believe that formal competitive markets are essential to enabling effective demand response. However, they also point out that RTOs are not unique in their ability to support the formal wholesale markets. And, more importantly, they remind us that addressing market power is a critical prerequisite to capturing the efficiencies offered by formal markets.

Improving the quality of analyses on this subject will be difficult. As is true for the issues of generation and transmission investment and enhancement, consistent data on wholesale market operations are scarce, and robust theories and methods for rigorously assessing the data are in their infancy. FERC's market monitoring requirements for RTOs and ISOs have led to some data collection and analysis at the RTO or ISO level, but comparisons between markets remain difficult. More comprehensive data collection is needed, starting with generator access and service denial, cost and quality of transmission service available to generators, cost of congestion, volume and frequency of curtailment, flow of power (trade) across regions, and the price differentials that correspond to these factors.

Conclusion

Our review of recent benefit-cost studies finds many uncertainties and unexamined impacts that preclude a definitive assessment of FERC RTO policies. Although technical improvements in the methods traditionally used to conduct these studies will be helpful, future efforts should be devoted to studying impacts that have not been adequately examined to date, including reliability management, generation and transmission investment and operational efficiencies, and wholesale electricity markets. The potential benefits (and costs) associated with these as-yet incompletely studied impacts could easily outweigh the limited benefits and costs that have been studied to date. Failure to consider these impacts creates an incomplete and potentially misleading picture of the total impact of FERC's policies.

Systematic consideration of these impacts is neither straightforward nor possible without improved data collection and analysis. We hope that this review will advance the development of these much-needed data and methodologies.

1. Introduction

During the past three years, government and private organizations have issued more than a dozen studies of the benefits and costs of Regional Transmission Organizations (RTOs). Most studies have focused on benefits that can be readily estimated with traditional production-cost simulation techniques, which compare the cost of centralized dispatch under an RTO to a less-centralized dispatch in the absence of an RTO, and on costs associated with RTO start-up and operation. Taken as a whole, it is difficult to draw definitive conclusions from these studies due to methodological limitations and lack of available data. In particular, the studies have not examined potentially much larger benefits (and costs) resulting from the impacts of RTOs on reliability management, generation and transmission investment and operation, and wholesale electricity market operation.

This report reviews the state of the art in RTO benefit-cost analysis. The review is motivated by the following considerations:

1. FERC policies regarding RTOs are having and will continue to have wide-ranging impacts on the production, transmission, and consumption of electricity. Public-policy makers want to know the size of those impacts.

2. The data and the methodologies needed to inform policy makers are incomplete. Some impacts can be estimated at this time, others will require some time to assess, and some may never be estimated quantitatively. The approaches and data used in recent studies allow us to begin to identify and prioritize needed improvements in data and methods.

Section 2 introduces benefit-cost analysis of Federal Energy Regulatory Commission (FERC) policies. We review the Environmental Impact Statement (EIS) prepared for FERC Order 888 in 1996 and the Environmental Assessment (EA) prepared as part of Order 2000 in 1999. The EIS broadly conceptualizes the expected economic and reliability impacts of Order 888 and presents modest quantitative findings on an equal footing with necessarily qualitative findings based on analogies drawn from other industries. We express the EIS's initial description of potential impacts using a standard economic framework for assessing benefits and costs.

Section 3 reviews 11 RTO benefit-cost studies that were conducted between 2002 and 2004. See Table 1.1. These studies primarily consider the tradeoff between <u>benefits</u> in the form of short-run production-cost efficiencies and <u>costs</u> for the start-up and operation of an RTO. We contrast these studies based on several of their components, including:

1. Specification of baseline case and of policy changes resulting from RTOs,
2. Scope of benefits-costs considered,
3. Production-cost simulation methods used for analysis, and
4. Costs of RTOs vs. cost impacts on other market participants.

In each discussion, we: a) clarify the principal analytical or data challenge(s) involved, b) review the approaches used by the studies, and c) comment on promising approaches or insights that could be helpful in future studies.

Section 4 reviews important impacts of FERC policies that have been overlooked or incompletely treated by recent RTO benefit-cost studies, including impacts on reliability management, generation and transmission investment and operation, and wholesale electricity market operation.

Recent studies should not be criticized for failing to consider these additional areas of impact because, for the most part, neither data nor methods yet exist on which to base a definitive analysis. Thus, Section 4 focuses on identifying the challenges in moving from the current generation of studies toward more comprehensive future assessments.

Table 1.1 Overview of Recent Studies of RTO Benefits & Costs

Study Sponsor	**Study Scope/Objectives** (as described in text of studies)
Pennsylvania-New Jersey-Maryland Interconnection (PJM). 2002. *Northeast Regional RTO Proposal Analysis of Impact on Spot Energy Prices*. January. Sponsored by PJM	Analyzes costs-benefits of the Northeast Regional RTO (PJM, PJM West, New York, and New England), including effect of energy prices in all three regions and regional energy-market clearing prices.
ICF Consulting. 2002. *Economic Assessment of RTO Policy*. February. Sponsored by FERC	Assesses economic costs and benefits of a national move toward RTOs, including improvements in transmission-system operations with resulting enhancements to inter-regional trade, congestion management, reliability and coordination; and improved performance of energy markets.
Tabors, Caramanis, and Associates (TCA). 2002. *RTO West Benefit/Cost Study*. March. Sponsored by RTO West Filing Utilities	Analyzes, quantitatively and qualitatively, the relative merits of establishing RTO West and the influences RTO West would have on commercial, wholesale markets.
Energy Security Analysis, Inc (ESAI). 2002. *Impact of the Creation of a Single MISO-PJM-SPP Power Market*. July. Sponsored by MISO-PJM-Southwest Power Pool (SPP)	Analyzes the impact of establishing a joint, common electricity market encompassing 26 states, the District of Columbia, and the Canadian province of Manitoba.
Independent System Operator-New England (ISO-NE), New York Independent System Operator (NYISO). 2002. *Economic and Reliability Assessment of a Northeastern RTO*. August. Sponsored by ISO-NE and NYISO	Assesses wholesale electricity market impacts and organizational impacts of establishing a Northeastern RTO (NERTO), including the potential costs of implementing NERTO and savings from the market efficiencies and operational consolidation expected to result from NERTO.
Charles Rivers Associates (CRA). 2002. *The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast*. November.	Analyzes the benefits and costs of establishing RTOs in the southeast (GridSouth, SeTrans and GridFlorida) in conjunction with the adoption of the Standard Market Design (SMD).

Sponsored by Southeastern Association of Regulatory Utility Commissioners	
U.S. Department of Energy (DOE). 2003. *Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design*. April. Sponsored by DOE	Assesses potential impacts of FERC proposed rulemaking: "Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design."
Cambridge Energy Research Associates (CERA). 2003. *Economic Assessment of American Electric Power's Participation in PJM*. December. Sponsored by American Electric Power (AEP.)	Quantifies the costs and benefits of AEP's integration into the PJM markets.
Science Applications International Corporation (SAIC). 2004. *The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets*. March. Sponsored by Midwest Independent System Operator (MISO)	Evaluates proposed financial transmission right (FTR) allocations and overall impact of market participation on Wisconsin consumers.
CRA. 2004. *The Benefits and Costs of Dominion Virginia Power Joining PJM*. June. Sponsored by Dominion Virginia Power (DVP)	Assesses net benefits of DVP joining PJM: net benefits to DVP's Virginia jurisdiction retail customers and collectively benefits for all retail and wholesale customers in DVP control.
Henwood Energy Services, Inc. 2004. *Study of Costs, Benefits and Alternatives to Grid West*. October. Sponsored by Snohomish County Public Utility District.	Analyzes costs and benefits of as well as alternatives to forming a new RTO in the northwest, currently referred to as Grid West.

2. The Role of Benefit-Cost Analysis in Evaluating FERC Policies

Benefit-cost and cost-effectiveness analyses have become a central element of federal government rulemaking. These analyses attempt to put a dollar value on all benefits and costs of a proposed rule. Regulations whose benefits exceed costs are considered potentially worthwhile, at least from an economic perspective. The federal government has refined its expectations for regulatory analyses in general and benefit-cost analysis in particular, beginning with the Office of Management and Budget's "best practices" document of 1996 and culminating in the Circular A-4, *Regulatory Analysis* (September 17, 2003).[3] Most regulatory analyses to date have been done in the areas of health, environment, and safety where market values often do not fully reflect social values. FERC has examined some aspects of electricity industry restructuring through the lens of benefit-cost analysis.

FERC began restructuring the U.S. electricity industry in 1996 by ordering utilities to open their transmission grids to unaffiliated generators. The Environmental Impact Statement (EIS) accompanying the open-access orders (888 and 889) contained a benefit-cost analysis of the economic impact of these orders (FERC 1996). Four years later, in Order 2000, the FERC encouraged but did not order utilities to join RTOs. The Environmental Assessment (EA) accompanying Order 2000 supported the commission's general presumption that region-wide benefits from RTOs would exceed their costs (FERC 1999). Not surprisingly, FERC found at that time – and researchers continue to find – that some benefits and costs are extremely difficult to value even when they are primarily economic in nature.

The following subsections review the findings from the EIS and EA and analyze specific issues related to assessing the costs and benefits of electricity industry changes. Section 2.1 reviews the scope and findings of the EIS and EA related to FERC Orders 888, 889, and 2000. Section 2.2 formally examines the analytical structure of benefit-cost analyses. Section 2.3 addresses special considerations related to assessment of wholesale electricity markets. Section 2.4 describes how benefit-cost analyses can be usefully applied to the problem of estimating RTO benefits.

2.1. FERC's EIS (1996) and EA (1999) Benefit Studies

FERC's 1996 benefit-cost study projects that the benefits from open access would fall into four categories:

1. Better use of existing assets and institutions,
2. Technical innovation,
3. New and more efficient market mechanisms, and
4. Less rate distortion.

Better use of existing assets include such things as reducing fuel use per megawatt at individual generators and by meeting demand with the most efficient generators. As

[3] See http://www.whitehouse.gov/omb/circulars/

contrasted with these short-term improvements in production efficiency, FERC also believed competition would contribute to dynamic efficiency by encouraging faster adoption of improved technologies than experienced under regulation. New market mechanisms include spot and futures markets, time of use pricing, and offers of different service qualities. Rate distortions refer to charges and subsidies that cause prices of services and electricity to differ from their marginal costs. Independent generators, for instance, face charges for using transmission that bear no relation to the costs they impose on the grid. These market innovations would improve the allocation of electricity by allowing consumers to buy what they want at prices that reflect their (marginal) cost.

Consistent with FERC's national perspective, FERC analyses include all beneficiaries, consumers, producers, and society at large, without regard to circumstances or location. (E.g., the geographical distribution of costs and benefits/ losses and gains are not considered.) Benefits are measured relative to a baseline that extends the status quo – i.e., the state of things in the absence of the proposed FERC order – into the future. The baseline assumes that existing asset utilization efficiencies, technical innovation rates, markets functioning, and rate distortions would remain unchanged from then-current values.

At the time of the 1996 study, FERC anticipated that open access would increase competition from new market entrants, which would pressure utilities to lower costs (production efficiency) and seek improved technology (dynamic efficiency), especially for transmission-system control, quick-response generation, and re-powering of older generators. The commission correctly anticipated the birth of one type of market mechanism, public spot markets, and underestimated the difficulty of establishing another, viable futures markets. The commission also expected open access would focus attention on inefficiencies in transmission rates and lead to their reform. As it turned out, eastern independent system operators (ISOs) revolutionized transmission rates by explicitly charging for congestion and introducing tradable financial rights to transmission service.

The commission's EIS estimates benefits of between \$3.8 and \$5.4 billion for the reference year 2005, *solely as a result of more efficient use of existing generating facilities*. Savings in fixed operations and maintenance (O&M) costs are estimated to yield \$2.1-\$3.5 billion and fuel and capital saving are estimated at about \$1.6 billion. The remaining estimated savings are in variable O&M. Potential benefits associated with more efficient use of transmission facilities are not included in these estimates.

The EIS declines to estimate savings in technical innovation, new and more efficient market mechanisms, and less rate distortion. In discussing how spot markets and futures trading would improve risk management, the EIS acknowledges, "It is virtually impossible to quantify the benefits thus obtained."[4] The EIS draws examples from other recently restructured industries to illustrate the types of innovations expected.

[4] FERC (1996), Section5.2.6.11, New Market Mechanisms, paragraph 6.

In its 1999 EA, FERC anticipated that RTO benefits would be concentrated in transmission-grid management and planning, reliability, and reductions in transmission-cost. These benefits would be over and above those identified in the 1996 study; in other words, the RTO baseline in the 1999 study assumes the generator savings (the benefits from improved production efficiency) that had been projected in the 1996 EIS. In particular individual generators are assumed to operate efficiently in the RTO baseline-RTOs could however obtain cost reductions by better using (dispatching) generation.

In the 1999 EA, FERC's list of specific benefits from RTOs include:

1. Better congestion management.
2. Improved grid reliability.
3. Regional transmission pricing.
4. Retail access.
5. Elimination of rate pancaking.
6. Less discrimination in transmission practices.
7. Reduced transaction costs.
8. Improved planning .
9. Better coordination of state regulatory agencies[5].

FERC argued that explicitly pricing transmission in regional markets to reflect the system wide costs of congestion would lead to better congestion management, eliminate rate pancaking, lessen discrimination and reduce transactions costs. In addition, market participants would be expected to improve planning and regulatory coordination once the actual cost of transmission was visible.

Congestion costs are qualitatively different from out of pocket, unavoidable costs like fuel costs. They arise because the least costly collection of generators cannot be used to meet demand when lines are congested.[6] Whether and how the system is congested depends on the decisions of all generators and consumers. The additional cost of meeting demand is a measure of congestion cost. Regional transmission pricing is designed to make each generator and each consumer pay for the marginal congestion costs it imposes on the system. In that way each generator and consumer is motivated to operate at an appropriate level (that configuration that maximizes system wide benefit in the presence of transmission constraints).

Absent a collective decision to impose congestion charges, individual generators do not pay for the costs they impose on others. At most their generation is cut back by dispatchers attempting to preserve the reliability of the system. Individual customers do not pay more for congesting the system; at most they are blacked out. Nevertheless these costs are real-they just don't appear explicitly on companies' books and consumer's bills. Instead they are rolled up into operating costs that are higher than they would otherwise be. Congestion charges only make visible costs that have been incurred all along-they are not an additional cost of regulation to be subtracted from benefits.

[5] FERC (1999), pages 89-90, "Description of Benefits."
[6] See Lesieutre and Eto (2004).

Reliability is also a collective good that cannot be individually bought and sold. Unfortunately reliability is very hard to quantify and price meaningfully.

The EA estimates incremental benefits from RTO formation for the nation as a whole for the period 2000 to 2015.[7] FERC's "best" estimate of annual benefits is $2.4 billion, but the EA indicates that annual savings could be as large as $5.1 billion under some (less likely) circumstances.

2.2. Overview of Benefit-Cost Estimation

Rulemaking benefit-cost studies attempt to put a dollar value on all benefits and costs that will result from a regulation. In the case of establishing RTOs, the major investment is the one-time cost to set up, train, and equip the new organization. Once up and running, an RTO generates a stream of net benefits (and costs). "Net" emphasizes that the costs and benefits being estimated are over and beyond the status quo baseline, i.e., the stream of costs and benefits that the existing system would yield *without* the RTO. Because the costs and benefits of RTOs are spread over many years, the dollar values of net benefits are calculated at each point in time, discounted to the present, and summed. The present value of future net benefits is then compared to the investment in the RTO itself. If the present value of future net benefits generated by the RTO exceeds the investment in the RTO, the investment is economically justified; that is, its benefits, expressed in dollars, exceed its costs.

The baseline economic data that describe a competitive market at a particular time are summarized by the market's demand and supply curve. Figure 2.1 shows a textbook competitive market in equilibrium at a particular time (i.e., a particular hour, day, or year). In a competitive market, consumers continue to buy as long as the benefit to them of each additional unit purchased exceeds the unit's price. Likewise, suppliers increase deliveries as long as the revenue gained from selling one more unit (i.e., the unit's price) is at least as much as the unit's additional (marginal) cost. These forces are resolved in market equilibrium: supply equals demand at the market quantity, price equals marginal cost, and price also equals marginal benefit. In this setting, "price" refers to the delivered price of the commodity. "Cost" refers to all the costs associated with producing, distributing, marketing, and delivering the commodity.

[7] FERC (1999), pages 93-94.

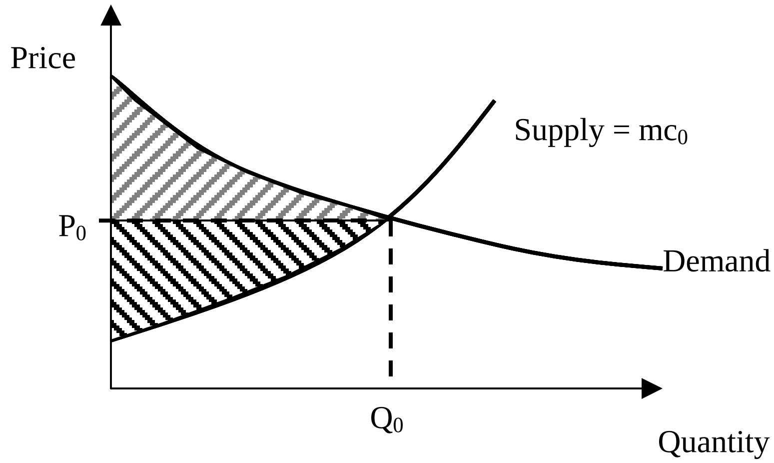

Figure 2.1. Textbook Competitive Market Equilibrium and Market Surplus. The upper and lower shaded areas represent consumer and producer surpluses, respectively.

Baseline economic benefit is represented by market surplus, which is the area below the demand curve and above the supply curve in Figure 2.1. Market surplus represents the difference between what people would be willing to pay to consume the market quantity, the area under the demand curve up to Q_0, and what it costs to deliver the market quantity, the area under the marginal cost curve up to Q_0. Consumer surplus is the part of market surplus lying above market price; it represents the difference between what people would be willing to pay for the market quantity and what they actually pay (P_0xQ_0). Similarly, producer surplus is the part of market surplus lying below the price line; it represents the difference between what producers receive (P_0xQ_0) less what it costs to provide Q_0, the area under the marginal cost curve up to the market quantity.

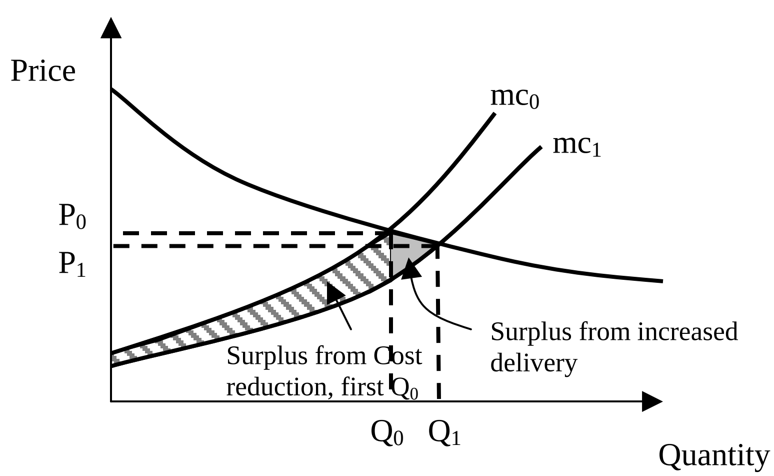

Figure 2.2. Net Benefits. The lowering of marginal production costs from mc_0 to mc_1 increases total surplus by the amount shown in the shaded areas.

Net benefit from a prospective regulatory action is the change in market surplus. Market surplus is divided between changes in consumer and producer surplus. As illustrated in Figure 2.2, any change in the market that reduces marginal cost will increase total surplus. The net benefit of marginal cost reductions (increased surplus) is indicated by the cross-hatched and shaded areas. Notice that the net benefit comes from the reduced cost for the units originally delivered (Q_0) plus additional surplus associated with the additional units delivered to the market (Q_1-Q_0).

It is important to realize that increases in net benefits will probably not benefit everyone. Figure 2.3 shows some examples. In Figure 2.3 (a), the effect of lowering the marginal costs of the lowest-cost supply while leaving higher-cost supply unchanged has the effect of increasing producer surplus (and total surplus) while keeping consumer surplus unchanged. Producers benefit from this change. In Figure 2.3 (b), higher-cost generation is replaced by mid-range-cost supply (mc_1 departs from mc_0 as a flat line). The result is an increase in consumer surplus (and total surplus) but a decrease in producer surplus. Consumers benefit from increased delivery and lower price delivery; producers lose.

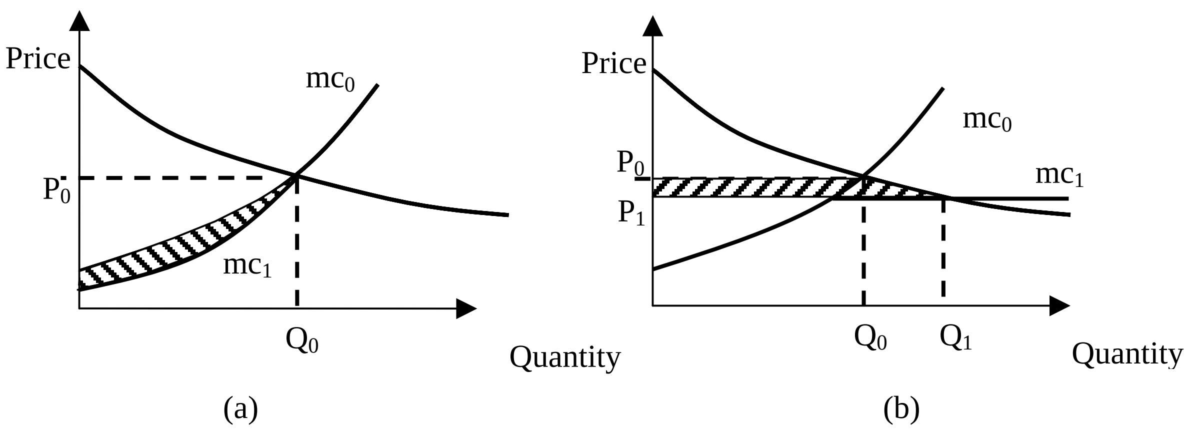

Figure 2.3. Divisions of Net Benefits. In (a) there is an increase in producer surplus while consumer surplus remains constant. In (b) there is an increase in consumer surplus and a decrease in producer surplus.

Over time demand and supply curves can shift position and change shape. Consumers may use more electronic devices; industries can adopt more or less electricity intensive production technologies. Investment in the grid, generation and system control can dramatically impact the shape of the supply of delivered electricity. Consequently to calculate market surplus it is necessary to characterize the impact of regulation on future supply and demand. Given demand, dynamic efficiency obtains when the level and mix of investment maximizes the present value of surplus. Competitive markets operating in an idealized world of perfect future markets are dynamically efficient.

One motivation for restructuring was the belief that utilities invested too much and invested in excessively risky ventures, including nuclear power plants. That was alleged to happen because price regulation ensured regulator approved investments would earn a market return. Shareholders effectively passed investment risk off to the shareholders. Now that shareholders are facing financial risk some analysts argue that the cost of capital for electricity investments has increased (Price C. Watts 2001). Others argue that, like congestion costs, restructuring only makes visible the true cost of capital that previously was borne by ratepayers.

This analytical framework is well suited to competitive markets where the relevant social costs and benefits are fully reflected in dollar revenues and expenditures of private entities. (In other words, there are no important “externalities.”) Regulation, however, is often focused on noncompetitive markets. Regulation is also focused on industries with large costs that are not reflected in the commodity’s market price but instead spill over to others. Pollution from uncontrolled coking coal furnaces, for example, imposes costs on people and other firms in the vicinity. Because there are no markets to price emissions reductions, analysts are forced to estimate the marginal benefits and marginal costs of emissions reductions, which is a daunting task.

Traditional regulated electricity markets are not competitive. Electricity is priced at its average (not marginal) cost; customers never see marginal costs and generally cannot adjust their consumption to price (marginal cost) fluctuations; investments must be approved and are often mandated by regulators; and, returns on capital are limited. As discussed in the next section, transparent public markets are new to the domestic electricity industry.

Most studies assume that the RTO world will be close to competitive, especially on the production/supply side. The analytical difficulty faced by all the studies is to adequately characterize the pre-RTO noncompetitive electricity market. That includes describing quantitatively how generators are dispatched, how congestion and its costs are handled, how power flows across political and organizational boundaries are managed, who can buy and sell, under what terms, and a host of other details describing the existing institutions. Chapter 3 describes how that has been done in considerable detail.

Electricity markets also have significant reliability and congestion externalities. These external costs are not priced in traditional markets. Generators, consumers, and system operators all make choices that affect system reliability for everyone. Likewise, generation and consumption within an RTO can have significant impacts on the costs and deliverability of electricity both within and outside the RTO’s boundaries. Quantitatively estimating reliability, valuing it, and showing the link between reliability benefits and the pattern of industrial organization are not currently feasible even though, as we will explore in Section 4, changes in reliability may be a major benefit (cost) of RTOs.

Finally, it is important to note that the traditional benefit-cost framework assumes a market that is functioning well. However, experience since Order 888 has shown that public wholesale power markets do not spring up on their own; they have to be consciously designed and created through cooperation between regulatory authorities and market participants. Public wholesale markets are unique to RTOs. Thus, one issue that must be addressed is the benefit from public markets compared to private markets. We explore this issue in the next subsection.

2.3 Wholesale Electricity Markets

Prior to electricity-industry restructuring, short-term wholesale trades were negotiated privately among utilities. Most trades were made to relieve temporary surpluses and deficits.[8] The lack of a market price and standard delivery terms meant that each transaction had to be arranged from scratch. To avoid paying too much or charging too little, buyers and sellers invested in price discovery. When several utilities were involved in a deal, the problems of price discovery and coordinating power delivery were significant. The costs of price discovery and negotiation discouraged some trades; the lack of market prices hid beneficial opportunities from market participants.

The public spot-market prices in RTOs greatly reduce price-discovery costs. Any qualified agent can buy or sell power in an RTO, and both buyer and seller know that they can acquire or dispose of supplies at the market price, without separate negotiations to arrange delivery. This set-up makes it easy to identify mutually beneficial trades.

Spot markets can also function as virtual suppliers and customers. If a generator discovers that the spot price is less than his marginal cost, s/he can meet his/her contractual obligations by purchasing power on behalf of his/her customer. Likewise, if a generator discovers that his/her marginal costs are less than market price, s/he can increase generation beyond what his contract customers demand without concerning him/herself with who actually buys his/her additional supplies. Otherwise, s/he would be forced to honor his/her contract by generating inefficiently.

Current studies do not directly quantify the out-of-pocket costs of price discovery and negotiation. They can, however, indirectly pick up the dead-weight loss of missed opportunities in the difference between least cost and realized costs.

Some observers have cited the volatility of wholesale electricity prices as a cost of RTOs. However, this volatility is not a result of the RTO. Prices rise and fall naturally with marginal cost. That is, as demand rises, additional generating units with higher operating costs must be turned on; as demand declines, the units with higher operating costs are shut off. Thus, spot markets do not cause volatility in marginal costs; they merely record it.

By making spot prices visible, public markets make it possible to use “contracts for differences” and other financial arrangements to manage price risk. If a generator and a customer both want a guaranteed price, say $35/megawatt hour (MWh), they can guarantee that price using a contract for differences. The generator sells on the spot

[8] System operators could also order generators to decrease or increase output to relieve surpluses or deficits, respectively. Those changes can be costly, especially if generators are shut down or restarted.

market, and his/her customer buys on the spot market.[9] If the customer pays less than $35/MWh, s/he sends the savings to the generator. If s/he pays more, the generator sends the excess to the customer. Whatever the spot price, both are guaranteed a price of $35/MWh. Other contracts provide varying degrees of price certainty while transferring price risk from those who do not want to bear it to those who do.

The reality is that liquid futures and options markets have not developed. Until they do, market participants will have limited means for managing spot-price or basis volatility.

Visible prices can also have other benefits. Once consumers can see prices, they can choose to respond by consuming only when it is worthwhile to them, i.e., when the marginal benefit from additional consumption exceeds its price. As shown in Figure 2.4, marginal cost pricing unambiguously increases market surplus. Figure 2.4 (a) shows the case where the regulated price is less than the competitive price. The fixed demand at that price is shown by the heavily shaded line. Because regulated utilities are bound to meet demand at the regulated price, they deliver electricity that costs more to generate than it is worth to consumers. The shaded area lying between the competitive quantity and the regulated quantity is a social loss. It has to be offset against the net benefits of consuming up to the competitive quantity, shown by the cross-hatched area. Likewise, if the regulated price is too high, then too little is consumed. Given the freedom to trade, consumers would want more electricity, and utilities would want to deliver more.

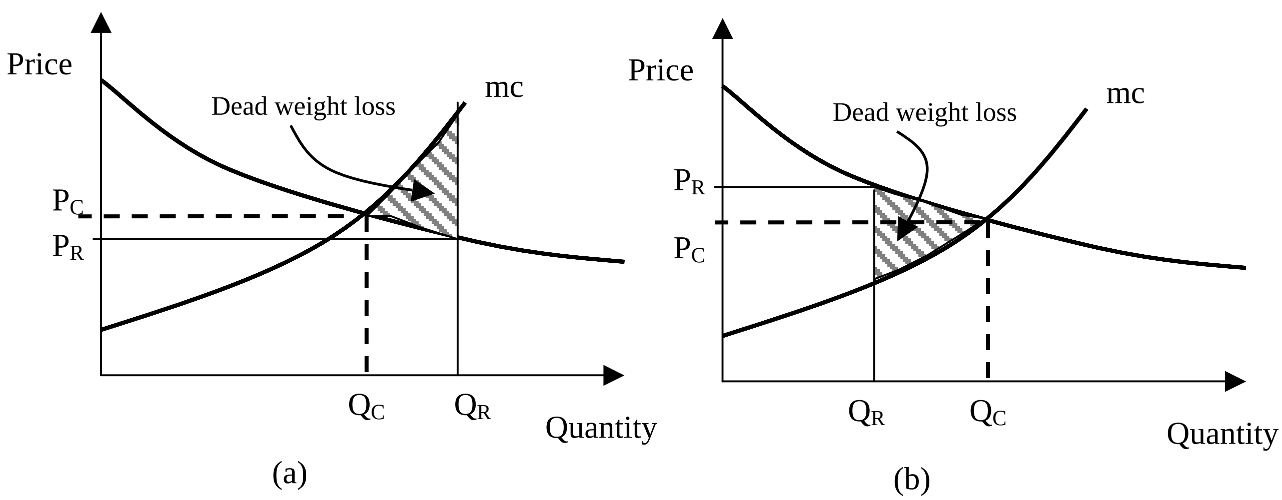

Figure 2.4. Dead-weight loss of regulatory pricing. (a) Regulated price is less than competitive price. (b) Regulated price is greater than competitive price.

Increasing price response would by itself increase market surplus. Currently there are very few examples of real-time pricing in electricity markets. It is too early to say

[9] This example assumes a single spot market, thus eliminating basis risk, which is the chance that the prices in the generator's spot market differ from those in his/her customer's market. The continuing reality of large basis risks in electricity has meant that most risk management contracts are available only in the over-the-counter market.

whether that is because spot prices are new, because there is institutional resistance, or because the benefits are relatively small.

Schweppe et al. (1988) has pointed out that price-sensitive consumption would also have significant reliability benefits. When the system is stressed, prices rise, and consumers automatically curtail consumption. That price response reduces peak demand and reduces the need for expensive peaking capacity to meet demand during a few hours per year.

Spot pricing also opens the door for new reliability products. Chao and Wilson (1987) pointed out that real-time prices could be used to give customers the option of choosing among different levels of reliability. Customers who need very high-quality power could get it, but those whose needs are less stringent would not be forced to buy a high-quality product.

2.4 Application to RTO Benefit-Cost Studies

The benefit-cost studies reviewed in this report define the market as the system within the given RTO's footprint. The marginal cost of delivered electricity in these studies includes: marginal production costs; direct transaction costs such as transmission tariffs, price discovery, and risk management costs; "friction" costs (i.e., use of higher-cost supplies when lower-cost supplies are available); and system control, coordination, and reliability costs. In most electricity markets, retail customers do not see market prices; instead, they pay a fixed price determined by regulators. As a result, total wholesale demand is not sensitive to price, and cost reductions do not yield an additional consumption benefit. The net benefit is simply the cost reduction shown in Figure 2.5.

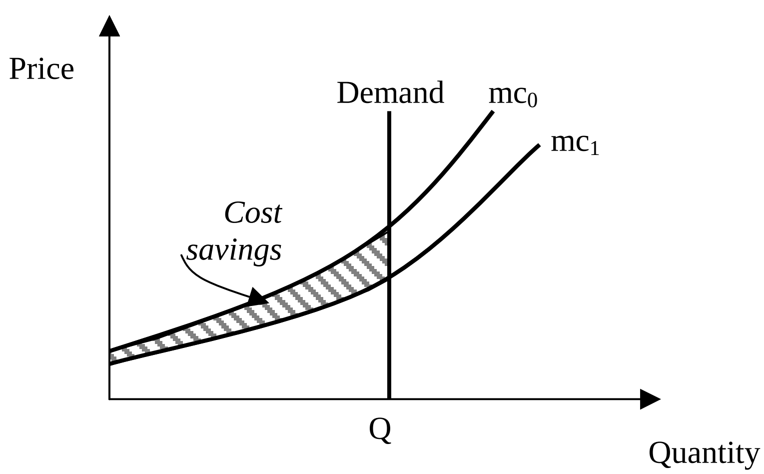

Figure 2.5. Electricity Market, Demand Not Price Responsive.

As mentioned in Section 2.2, typically, a "status quo" case is taken as the baseline for valuing benefits and costs. The "status quo" case assumes that Orders 888 and 889 are in place and that any production-cost benefits available at individual generators are already realized. In the "RTO case," all system resources are centrally managed to minimize the costs, within the RTO, of meeting demand.

RTOs are designed to use all existing assets to minimize the cost of meeting a fixed slate of demands. However, in the near term, RTOs would not improve instantaneous efficiency if the costs of meeting demand were already minimized because all of the following were true: existing suppliers were efficient, electricity was acquired at the lowest price regardless of source within the boundaries of the RTO (i.e., transactions were not artificially constrained by franchise boundaries), and supplies were offered at marginal cost.

Most studies use the RTO case to represent cost minimization across the region because of the multitude of ways in which real systems can fail to minimize cost. Thus, the RTO is assumed to capture many of the *short-run* benefits that FERC expects, i.e., the RTO will: efficiently manage congestion, eliminate arbitrary local transmission charges, end rate pancaking and supplier discrimination, and reduce transactions costs. Sections 3 and 4 of this report analyze in detail the methods and assumptions used to estimate the benefits and costs of RTOs and the need for significant improvements in these methods, specifically the need for current methods to address expected benefits from improved reliability, generation and transmission investment and operating efficiencies, and wholesale electricity markets.

In order to determine the status quo baseline, the study must estimate how much it differs from the RTO. That entails making plausible estimates of congestion, the effect of arbitrary local rates, the effect of pancaking on generator dispatch, and the effect of supplier's discrimination in the existing environment on generator utilization.

One way to estimate the economic consequences of these phenomena is to compare generator scheduling and dispatch in the past with what they would have been had costs been minimized throughout the RTO. If the existing system were efficient, these two would be the same, and there would be no cost penalty. If there is a cost penalty, it can be projected based on historical experience and anticipated near-term demands and costs.

Another approach would be to use historical data to estimate congestion, generator scheduling and dispatch, transmission charges, and wholesale prices under a variety of conditions. Those relationships could be used to simulate how the system would be used in the future. Given that information, analysts could calculate the difference between the "status quo" and the RTO baseline.

Instead, most studies impose hurdle rates on generator costs. This topic is explored at length in Section 3.3. Hurdle rates distort the least-cost supply curve to approximate the past. Using the terms of Figure 2.1, we can see hurdle rates "in action" as follows: either unnecessary congestion, arbitrary transmission charges, or a policy of favoring the transmission operator's own generation, or allowing unnecessary congestion would result in some high-priced generators artificially displacing low-cost producers. The effect is to reduce "status quo" surplus as shown in Figure 2.6. In an RTO, the lower-priced generators are dispatched instead of the higher-cost ones in the above scenarios, which results in an increase in consumer surplus and possibly even an increase in producer surplus, depending on the price change and relative costs of the high-priced to low-priced generators.

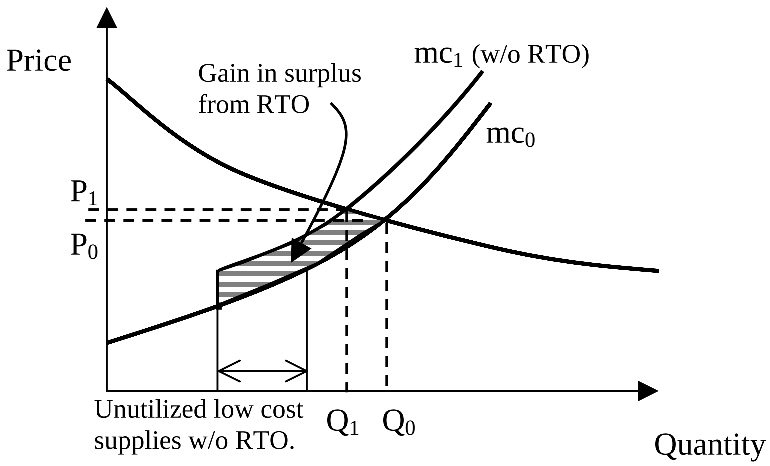

Figure 2.6. Impact of Higher-Cost Production on Baseline.

With a near-term RTO baseline and a “Status Quo” defined, the studies calculate the near-term cost of meeting demand in each case. Because demand is assumed to be unresponsive to wholesale price within the RTO, the RTO benefit is simply the reduction in the production costs of delivered electricity.

2.5 Summary

This chapter has outlined the major impacts of RTOs as first predicted by FERC in preparing Orders 888 and 2000. Identifying these anticipated impacts allows us to assess the extent to which recent studies of RTO benefits and costs have addressed them. We have outlined the principal economic benefit of RTOs, short-run production-cost savings, in formal economic terms because this is the primary benefit examined in the studies we review in the next sections of this report.

3. Review and Assessment of 11 RTO and Competition Benefit-Cost Studies

In this section, we review 11 studies of RTO benefits-costs and competitive electricity markets, all of which were published between 2002 and 2004.[10] These studies consider the tradeoff between *benefits* mainly in the form of short-run production cost efficiencies and *costs* in the form of the start-up and operation expenses of an RTO. We discuss these studies specifically in regard to their treatment of:

1. Specification of baseline case and RTO ("policy") case changes,
2. Scope of benefits-costs considered,
3. Production-cost-simulation methods, and
4. Costs of RTOs vs. cost impacts on other market participants.

For each item above, we: 1) clarify the key analytical or data challenge(s), 2) review the approaches used by the studies, and 3) comment on promising approaches to improve future studies.

3.1 Specification of Baseline Case and Policy Case Changes

The principal approach used by RTO benefit-cost studies, as outlined in Section 2.2, is comparison of two generation-dispatch scenarios. In the first scenario, called the base case or baseline, dispatch is calibrated (or, as we will discuss in Section 3.3, constrained) to represent the state of the electricity market without the policy under study (e.g., assuming that FERC Orders 888 and 889 are in place but that FERC Order 2000 has not yet been enacted). The second scenario, which we refer to as the policy case, typically assumes centralized dispatch (through an RTO), over a larger geographic region, and deploys the same fleet of generation as in the first case to serve the same loads interconnected over the same transmission network. The difference in generation-production costs between these two dispatch scenarios represents the net effect of the policy under examination.

Understanding how the base case or baseline is specified in a study is critical for understanding the study's findings, because the base case is the starting point from which the impact of a policy is measured. It is difficult to compare the findings of studies that employ different baselines even if these studies assess the same policy. In the remainder of this subsection, we discuss the general issues related to specification of the baseline and policy case(s) in benefit-cost studies. In the subsequent subsections, we discuss the presentation of the differences between the base case and policy cases (Section 3.2) and the methods used to calculate these differences (Sections 3.3 and 3.4).

[10] More than 11 benefit-cost studies were conducted during this period; and additional studies have been published since this research was initiated. We believe the 11 studies we review are broadly representative of current practices, but we do not suggest that our findings extend to all studies.

As one might expect, the baselines and policies examined in the studies that we reviewed have evolved over time, reflecting the evolution of industry discussion of FERC's policies. (Table 3.1 lists the studies and their perspectives). The earliest studies we reviewed focus on the potential impacts of FERC's initial policy preference for creating a small number of very large regional RTOs. PJM (2002), ESAI (2002), and ISO-NE/NYISO (2002) are all examples of studies in which the base case is a set of ISOs that existed at the time, and the policy case is the merger of two or more of these ISOs into an RTO.

Another group of early studies, notably TCA (2002) and CRA (2002), examined the formation of RTOs in areas of the country where ISOs had not yet formed. A more recent similar example is Henwood (2004). In these studies, the base case features highly decentralized dispatch by individual utilities and control areas. ICF (2002) uses a hybrid approach in which the entire country was examined as a handful of centrally dispatched larger RTOs.

CRA's (2002) findings were among the first cited by parties that objected to the direction of FERC's policies. DOE's 2003 study was conducted as a result of a congressional order to assess the benefits and costs of FERC's SMD Notice of Proposed Rulemaking NOPR (DOE 2003). In this study, the base case uses the existing dispatch of generation in areas both with and without RTOs.

Recently, studies have focused on the effects on parties that are deciding whether to join and enlarge the scope of an existing RTO. CERA (2003), SAIC (2004), and CRA (2004) are examples of these types of studies. They look at the incremental change resulting from centralized dispatch in the larger RTO footprint that would result from including additional RTO members.

Although we have focused so far on differences in baselines defined by different studies, the vastly different geographic scopes of the studies also create a major challenge for comparing and assessing study findings. Some studies are national in scope; others consider impacts for a specific region. Another challenge is reconciling differences in the metrics used to express the study results. Most studies focused on changes in overall production costs; some focused on electricity prices (and, as we will discuss in Section 3.2, there are also important yet subtle differences, especially among the more recent studies, in the perspectives from which these impacts are assessed). To compare the studies' findings, we have normalized the results by expressing them as a percentage of the base-case metric.

Consistent with FERC's original EIS analysis (1996), improvements in generation dispatch resulting from establishment of an RTO are found to offer modest reductions in total production costs from the assumed fleet of generation and the supporting transmission network. Annual savings are projected to amount to less than five percent and fall mostly in the range of one to three percent.

Table 3.1 Summary of Benefits, Baselines, and Perspectives

Study	Benefit Type/Benefits (% of base case)	Baseline	Additional Benefit-Cost Perspectives
PJM 2002	Load payments: $300M/yr (2%)	PJM, NYISO, and ISO-NE operated as separate RTOs.	PJM, NYISO, ISO-NE Production cost and revenue changes.
ICF 2002	Wholesale generation prices: $1.1B/yr (1.2%), rising to $7.5B/yr (5.0%); 20 yr net present value (NPV) is $41B (3.8%)	2001 mix of ISOs and vertically integrated utilities.	12 regions.
TCA 2002	Difference between load payment reductions and generator net revenue reductions: $300M/yr (n/a)	2002 mix of ISOs and vertically integrated utilities.	Subregions, WECC Consumer and producer impacts.
ESAI 2002	Price of energy: $1.7B/yr or $7.0B/10 year (both ~3%)	2002 mix of ISOs and vertically integrated utilities.	None
ISO-NE/ NYISO 2002	Wholesale power costs: $220M/yr (3.0%) in 2005 and $150M/yr (1.8%) in 2010	ISO-NE and NYISO	ISO-NE and NYISO
CRA 2002	Reduced generator payments + merchant generator net benefits: $2.1B PV 2004-2013 (<1%)	No RTO	GridSouth, SeTrans, GridFlorida, Eastern Interconnection Consumer and producer impacts.
DOE 2003	Wholesale electricity costs: $1.8B/yr to $1.5B/yr (both <1%)	2003 mix of ISOs and vertically integrated utilitie.s	12 regions
CERA 2003	Wholesale energy costs: $245M in 2004 to $188M in 2008 (n/a)	PJM w/o DVP	PJM and DVP, individually.
SAIC 2004	Reduced generation costs plus off-system sales and FTR revenue: $105M/yr (~8%)	MISO w/o Wisconsin utilities.	Wisconsin utilities Consumer and producer impacts.
CRA 2004	Total energy plus capacity and ancillary services savings: $800M/10 yr (n/a)		None
Henwood 2004	Pancaked wheeling rates, operating reserve cost savings, and transmission asset utilization: $78M/yr (n/a)	2003 mix of ISO and vertically integrated utilities.	None

The normalization approach works reasonably well for comparing results from the earlier generation of studies because the results in those studies generally include impacts on all parties within the RTO footprint. The normalization approach works less well for comparing results from recent studies because the impacts presented are typically only for a subset of affected market participants or particular geographic subregion (We discuss this issue next, in Section 3.2).

In examining the earlier group studies for which our normalization approach should be more useful, we hypothesized that the incremental gains, on a percentage basis, of going from an existing set of RTOs to a larger "super RTO" might be smaller than going from a state of no RTO to having an RTO. That is, we would expect if an RTO already existed, it would have already captured some benefits of centralized dispatch within its footprint, so combining RTOs would capture only the incremental additional benefits of centralized dispatch over an even larger footprint. This change would likely be smaller than the more dramatic change of going from having no RTO to having one and beginning to capture centralized dispatch benefits for the first time in the given region.

Unfortunately, because the number of studies is small, there is limited evidence on which to base an evaluation of this hypothesis. Neither TCA (2002) nor Henwood (2004) gives information regarding their base-case metrics, which would allow us to express their findings as percentages. SAIC (2004) and CRA (2002) are complicated because both take into account more than just production-cost differences between the two dispatch scenarios. This issue is discussed further in Section 3.2.

The above subsection has focused only on the specification of base and policy cases in RTO benefit-cost studies that is most commonly found in the reports we reviewed, i.e., that what defines these two cases is a change in production costs, generally assuming a fixed fleet of generation and transmission assets.

However, the change in production costs is a limited way to define a base vs. policy case, as can be seen through our analysis in other sections of this report. That is, in Section 3.3, we focus on the aspects of the change between base and policy cases that can be modeled directly using production-cost-simulation tools. In Section 3.4, we discuss how start-up and operating costs for RTOs are estimated and how this practice does not, by itself, take into consideration other changes in costs between the base and policy cases. More importantly, in Section 4, we review some RTO benefit-cost studies that expand the scope to include consideration of reliability, generation and transmission investment and operation, and wholesale market operation. All of these discussions point out different assumptions can be allowed to vary between the base and policy case. It is important to keep the different ways of defining the changes between the base and policy cases in mind when assessing the significance of the differences that each report finds between its base and policy cases.

Recommendation for future studies: 1) Clearly articulate assumed base-case conditions and assumed changes that define the policy case; 2) Provide rationale for assumed changes in policy case.

3.2 Scope of Benefit-Cost Perspectives

Most of the studies we reviewed were conducted or commissioned by parties within a given region, so the findings focus on impacts on one or more groups within that region. ICF (2001) and DOE (2003) are exceptions; both were sponsored by agencies of the federal government and adopt a national perspective. Table 3.1 lists the benefits and benefit types estimated by the studies we reviewed, and the perspectives from which these impacts are assessed.

Focusing on impacts on one or more groups within a region is a legitimate strategy when a study's goal is to understand the impacts of proposed federal policies on specific constituents or stakeholders. However, for the purpose of evaluating the overall impact of FERC policies, a focus on only one set of impacted groups (or, as we discuss in Section 4, on only one type of impact) to the exclusion of others does not give a complete picture of the impacts of FERC's policies on all affected parties.

Another concern raised by the studies we reviewed is, as we have noted earlier, that these studies focus only on the impacts of FERC policies that are most easily quantified given the types of data and study methodologies that are widely available. It is important that these studies not be interpreted to suggest that impacts that they do not analyze are not significant. Although it may be true that impacts not analyzed in a study may, in fact, be insignificant to all affected groups, it may also be true that the omitted impacts may be highly significant to some or all stakeholders. In the latter case, including these impacts could dramatically change the outcome of the assessment. Either way, if there is no presentation or discussion of the missing information, we simply cannot tell.

Finally, and perhaps of greater significance than the previous point, when a study does not address the impacts of a policy on all affected parties, the study misses the opportunity to assess what economists call "side payments." For example, if there is net reduction in total costs to all parties but some parties would see increased costs, then the gainers can afford to compensate (make a side payment to) the losers. In principle it is possible to arrange for a side payment from those benefiting to those who do not benefit in a way that leaves all parties better off than they were before. See Figure 2.3(b). This is not to suggest that mechanisms for arranging for side payments are costless. However, when the total net benefit is positive, failing to present information about the distribution of impacts eliminates the opportunity to assess the potential for side payments.

Among the 11 studies we reviewed, benefits and costs are expressed in two main ways: from a geographic perspective and from a market-participant perspective.

The **geographic perspective** is by far the most common among the studies we reviewed; this approach describes impacts on parties within defined geographic regions. Studies that employ this strategy include PJM (2002) and ISO-NE/NYISO (2002), which describe impacts of RTO formation on each of the existing ISOs (ISO-NE, NYISO, and PJM; and ISO-NE and NYISO, respectively). CRA (2002) considers separately each of the three RTOs that were proposed at that time for the southeast region. All of these studies are notable for presenting impacts on both individual geographic groupings and on aggregations of these groupings that very effectively illustrate the potential for side payments that could allow all parties to benefit.

Impacts outside the immediate study regions are often not considered at all. TCA (2002) and CRA (2002) are exceptions. TCA (2002) presents impacts for subregions and for the entire Western Interconnection. Similarly, CRA (2002) also presents impacts for the entire Eastern Interconnection.

The **market-participant perspective** describes impacts on producers separately from impacts on consumers. As discussed in Section 2, economic theory holds that changes in total production costs are only a partial measure of total social benefit. This is illustrated in Figure 2.2 where the social benefit is equal to the combined impacts on both consumer and producer surplus (the shaded and cross hatched areas). A study that focuses only on impacts on some, but not all, participant classes is incomplete.

The majority of studies equate changes in total production costs with direct benefits to consumers. In some cases, this can be misleading [see Figure 2.3 (a)]. Although this approach ensures that all production-cost benefits are captured, it ignores or does not address market-design elements that might allocate these benefits between consumers and producers.

The issue of using locational marginal prices (LMPs) to manage congestion illustrates some of the complexity of addressing impacts on both producers and consumers. As discussed in Lesieutre and Eto (2004), settlements based on differences in LMPs are a form of both transfer payment between consumers and producers and allocation of the net increase in social welfare. Henwood (2004), for example, critiques TCA (2002) for including congestion revenues as net benefit rather than as a transfer payment among market participants. In another example, SAIC (2004) considers the role of financial transmission rights (FTRs) as a means of offsetting some transfer payments by compensating the holders of FTRs, which are primarily the load-serving entities (and, ultimately, consumers, rather than producers).

Often, the market-participant and geographic perspectives are related because increased production from lower-cost producers in one geographic region is exported, reducing power-purchase costs for consumers in another region. The benefits reported in CERA (2003), which analyzes the effects of expansion of PJM to include AEP and DVP, illustrate the problems of not presenting all perspectives. The benefits that this study attributes to PJM and DVP include only changes in consumer surplus; potentially negative impacts on producer surplus in these regions are not reported. However, only producer benefits (due to increased production) are reported for AEP, and potentially negative impacts on consumer surpluses in the AEP region are not reported. As a result of this inconsistency, it is difficult to assess the net impact of the expansion.

A closely related issue is ratemaking, which is not treated directly in the studies we reviewed. This issue arises both here in discussing transfer payments resulting from market settlement procedures, as well as in Section 3.4 in discussing cost-recovery of RTO costs. Ultimately, ratemaking determines how specific market participants are affected by RTO (and non-RTO) market activities.

Recommendations for future studies: 1) Present and identify benefits and costs inclusively from a wide variety of perspectives, and 2) Clarify differences between transfers among market participants (and articulate the mechanisms by which they take place) and net changes in total societal costs.

3.3 Production-Cost-Simulation Methods

The main benefit that is assessed quantitatively in the studies we reviewed is the short-run economic efficiency gain that might result from a change in generator dispatch. The main analytic tool used to estimate this gain is production-cost simulation.

Production-cost-simulation tools are a mature technology and are appropriate for analyzing short-run, centralized-dispatch impacts of RTOs. However, because these tools were developed initially to evaluate options for vertically integrated utilities to expand generation and transmission, the scope of the economic dispatch issues that the tools can treat is limited. Current efforts to address the limitations include incorporating explicit representation of the dynamic capabilities of the transmission network and the competitive behavior of market participants. Understanding these limitations and the current state of efforts to address them helps us assess the numerical results that these tools produce.

Production-cost-simulation tools seek to minimize the cost of dispatching a static fleet of generation assets to serve a deterministic forecast of (typically hourly) loads (Kahn 1995). Figure 3.1 is a stylized representation of the cost-minimizing generation dispatch that the models seek to estimate. To minimize total production costs, generation with the lowest variable cost of production is dispatched first (“base load”), and generation with the highest variable cost of production is dispatched last (“peakers”).

The usefulness of production-cost-simulation tools in estimating the short-run economic benefits of RTOs can be easily understood. By virtue of having a larger footprint than individual utilities and providers, it is alleged that RTOs can reduce the total cost of dispatch by drawing from a larger and more diverse portfolio of generation options than the smaller entities whose dispatch operations are subsumed under the RTO.

The assumption underlying this approach is that individual entities within the RTO’s footprint do not have the same access as the RTO to the larger portfolio of generation, so the sum of those entities’ individual costs to dispatch the smaller portfolios of generation to which they do have access (in order to minimize the costs of serving their own loads) is greater than that of the single RTO seeking to serve these same loads. The accuracy of this assumption depends on at least four modeling issues that are addressed to varying degrees by the studies we reviewed:

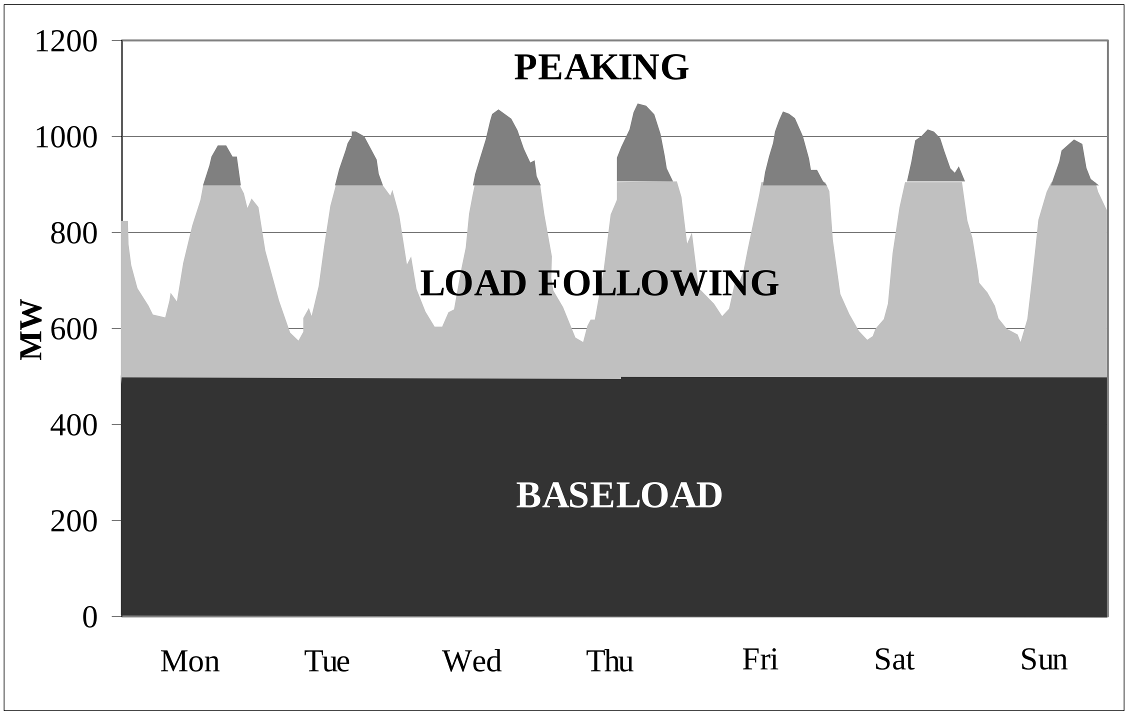

Figure 3.1 Stylized example of least-cost dispatch of three generic generation units for one week.

1. Treatment of long-term contracts,
2. Specification of so-called “hurdle” rates to mimic barriers to trade among and across the individual entities,
3. Representation of the dynamic nature of the transmission network, and
4. Reliance on reported generator production costs as proxies for the prices that would be offered by generators competing in RTO markets.

The first three issues above affect the extent to which the lowest-cost generation can be counted on to serve load before more expensive generators are needed. The fourth issue raises the question of the extent to which the studies can accurately predict the prices that generators would actually offer in RTO markets.

3.3.1 Treatment of Long-Term Contracts

The production-cost-modeling approaches taken by the studies we reviewed omit one important element of current power-system operations: long-term contracts. If all generation resources are not available for redispatch because some have physical contractual obligations to meet, then there may be errors in short-run production cost benefits that are estimated assuming that these resources *are* available for redispatch.

However, depending on the options and information available in the market, the effect of long-term contracts may be addressed financially and might not affect dispatch at all (see

Section 2.3). For example, if contracted generators have access to the wholesale market to meet their obligations, then production costs could, in principle, be unaffected (although determination of the allocation of consumer and producer benefits would require detailed accounting). That is, if a generator is contracted to supply energy at a price higher than the market price (and the market price is lower than that generator's cost of production), then the generator could purchase the power required to meet its obligation from the market rather than supplying the power from its own generation resources. The entity taking delivery would still be obligated by contract to pay the higher, contracted price for the electricity it receives. This situation would transfer wealth from consumers to producers in a way that would not be apparent from the production-cost simulation. Alternatively, if a generator has a contract to supply electricity at price lower than the market price, then the generator would likely produce the electricity from its own assets and not purchase the electricity from the market. In this case, too, total production costs would not change although the contract would involve a transfer of wealth from producers to consumers.

In summary, when there are viable spot markets, the treatment of long-term contracts in production-cost studies is primarily an accounting issue involving wealth transfers between producers and consumers.Thus, long-term contracts should not have a material effect on the ability of the production-cost simulation to produce a least-variable-cost dispatch scenario for all available generation assets.

On the other hand, academic research points to the very different incentives generators may have for exercise market power in situations when prices for significant portions of their capacity are set through forward contracts. We return to this general issue in Section 3.3.4.

Recommendation for future studies: Describe treatment of long-term contracts and "grandfathered" transmission agreements.

3.3.2 Specification and Use of Hurdle Rates

Hurdle rates play a critical role in production-cost-simulation studies of the benefits of central dispatch by an RTO. These rates are used to represent the "friction" between current, smaller dispatch regions that prevents these regions from individually obtaining the production-cost savings that are promised by central dispatch for the RTO's the larger, combined region. They are implemented as an increased cost for transactions across a geographic boundary.

Hurdle rates often serve two purposes. First, they are sometimes used when a base case is being prepared to help calibrate the production-cost simulation so that it replicates a historical pattern of generation dispatch. Second, they may be used in the preparation of a policy case; in this situation, the hurdle rate is reduced or modified from an initial level (regardless of whether the level was set initially to calibrate the base case) to enable the production-cost simulation to find a different (and usually lower-cost) combination of generation resources to meet loads aggregated from the base case.

Table 3.2 lists the hurdle rates used in recent production-cost-simulation studies. Some studies, such as TCA (2002) and Henwood (2004), use hurdle rates that are real in the sense that they represent actual wheeling charges that are being assessed by utilities for transport of power across their systems. Others modify an initial set of rates in order to match dispatch during a representative period of time (e.g., ISO-NE/NYISO 2002, CRA 2002). And, finally, some, such as DOE (2003), build on hurdle rates developed by earlier studies.

There are three generic issues associated with the use of hurdle rates in the benefit-cost studies we reviewed: 1) What are the standards for specifying hurdle rates and then using them to calibrate or benchmark the base case? 2) What is the mechanism or rationale for changing the hurdle rates (by what amount) in the policy case? 3) To what extent do hurdle rates represent real societal costs that would be changed if an RTO was dispatching generation?

With respect to the first two questions, there are no standards for specifying and then calibrating or benchmarking the base case to historic dispatch (or, for that matter, information on the extent to which such calibration is meaningful in examining future dispatch), nor is there readily analyzable empirical information on the actual changes resulting from greater central dispatch (compared to less centralized dispatch) of generators. As a result, specification of hurdle rates in benefit-cost studies appears to be as much an art as a science. Only a handful of studies provide numerical, albeit aggregated, information on the results of their calibration efforts (PJM 2002, ICF 2002, ISO-NE/NYISO 2002, CRA 2002, DOE 2003, SAIC 2004). And only one study (ISO-NE/NYISO 2002) presents information on the effects of selecting different hurdle rates on calibrations to past power transfers among regions.

With respect to the third question about the degree to which hurdle rates represent true societal costs, the issues involved are subtle. They include the historic cost basis for wheeling charges versus the marginal cost of providing wheeling services; wealth transfers among regions exporting, importing, and wheeling power versus real reduction in societal costs; and the difficulties of assigning a social value to transaction costs, broadly defined.

Recommendations for future studies: 1) Discuss (and present numerical results from application of) calibration standard and use of "tuning" mechanisms (e.g., transmission-path ratings), including the influence of these choices on the examination of the policy in question; 2) Document rationale for hurdle-rate adjustment in policy case; 3) Discuss treatment of hurdle-rate changes in different benefit-cost perspectives.

Table 3.2 Production-Cost Study Methods

Study	Tool	Study Year(s)	Base Case Hurdle Rates ($/MWh)	Benchmarking/Calibration
PJM 2002	GE-MAPS	2001	N/A – trade held fixed in base case.	Benchmarked to 2001 LMPs; numerical results not presented.
ICF 2002	IPM	2005-2020	Not presented; adjusted iteratively for calibration.	Within 5% of 2000 interregional generation flows.
TCA 2002	GE-MAPS		Actual wheeling tariffs w/in RTO $3.8 outside RTO.	Not presented
ESAI 2002	ZPM	2002-2012	$5	Not presented
ISO-NE/ NYISO 2002	GE-MAPS	2005 2010	NY-NE: $8-10; NE-NY: $6-11 NY-PJM: $9-10; PJM-NY: $ 4-7	Hurdle rates replicate flows to ~20% of historical levels between NY and NE, and 5% of historical levels between NY and PJM.
CRA 2002	GE-MAPS	2004, 2005, 2007, 2010, 2013	$10 commitment $5 dispatch	2000 coal plant output - +/- 1-2% for on- and off-peak hours.
DOE 2003	POEMS GE-MAPS	2005-2015	Eastern – $10 commitment; $5 dispatch Western – $5 commitment; $3 dispatch	On- and off-peak capacity factors of the southeastern coal plants; numerical results not presented.
CERA 2003	GE-MAPS	2004, 2006, 2008	$7.25 commitment $4.25 dispatch	Calibration conducted for separate multi-client study; not discussed in this study.
SAIC 2004	Promod-IV	2005	Hurdle rate was generally set at $3 for transactions between pools that were not in (the same) energy market.	Capacity reduced in base case using analysis of historic transmission loading relief events; numerical results not presented.
CRA 2004	GE-MAPS	2005, 2007, 2010, 2014	$10 commitment; $4 dispatch + loss on-peak; $2 dispatch + loss off-peak.	Calibration not discussed.
Henwood 2004	Marketsym/ Powerworld	2006	$0-6.3 (detailed list)	Calibration not discussed.

3.3.3 Representation of the Transmission Network

The transmission network is the "highway system" over which power is transported from generators to loads. Because of electricity's unique physical properties, the network's ability to support transport is not static; the network's ability to accommodate a proposed transmission of power at any given time depends on the total loading on the network resulting from all other uses of the network at that same time. Because production-cost-simulation tools are mainly used to study changes in power transport over the transmission network (i.e., how generation might be dispatched differently), the way a tool represents the network's dynamic capability can directly affect a study's results.

In some cases, the tool uses a coarse representation of the network, dividing the country or region into a few large areas connected by a few transmission paths. In other cases, a detailed representation is used with bus-level information and transmission-line power-flow models. The network connections that allow trade among regions (subregions, buses) are impeded by various constraints including:

1. Physical limits, beyond which additional power transfer is not possible;
2. Reliability limits, beyond which the system may be vulnerable to blackouts, which places a practical limit on operation;
3. Electrical impedance, which influences the flow of electricity, possibly restricting desired trade. (Electrical impedance is not always included in the models, especially in so-called "transportation" models, which are explained below.)

If the production-cost simulation can accommodate security-constrained economic dispatch, then physical and reliability limits may be incorporated and included in the solution.[11] Recognizing and taking into account security constraints is more important for short-term studies because the limitations (i.e., reliability-based contingencies) are known. In longer-term studies, because generation, loads, and network capacity are expected to change, sometimes significantly, the appropriate constraints would not be well understood, and attempting to account for them may not add to (and would likely detract from) the usefulness of the study's findings.

There are two basic types of models for electricity transmission. Very coarse aggregate tools (such as POEMS, IPM, ESAI) use a "transportation" model in which the energy-transfer limits on the different network paths are considered independent of each other. More detailed "transmission" models (e.g., GE-MAPS, Powerworld, Promod IV) allow the limits on one path to vary in a somewhat (though not necessarily completely) dynamic manner that depends on the loading of other lines within the network. See Table 3.3.

[11] In security-constrained dispatch, multiple scenarios are run; each scenario considers the loss of one or more key generation and transmission elements to determine whether the resulting configuration could be operated without violating various limits (e.g., thermal, voltage, and, in some cases, stability) that have been pre-set to ensure reliable operation. If a limit is violated, flows must be reduced to stay within the limit. Flows are reduced by changing the dispatch of generation away from the original, least-cost solution to a solution that is more costly but meets the security or reliability constraints.

In the more detailed models, one transmission line or path whose capacity is limited for reliability reasons can restrict the power-flow capacity of other lines and paths as well. This is due to parallel or "loop" flows, which are determined by the electrical impedances in a network and Kirchoff's laws. Loop flows result when an increase on one line that appears to have capacity available would lead to increased flow along another line that is already at its capacity limit. Thus, the capacity of the first line is effectively limited by that of the second.

In addition to limiting capacity in ways that are not represented in transportation models, detailed transmission models may "permit" seemingly uneconomic local trade in order to minimize overall costs. For example, it is possible in a transmission model to have energy flow from a high-price node to a low-price node if this flow allows for even greater flow from a low-price node to a high-price node elsewhere in the network. By contrast, in a transportation model, no trade from a high-price node to a low-price node is ever "allowed."

In general terms, a transportation model will tend to overestimate trade between regions compared to a more detailed transmission model. For short-term studies, this error may or may not be significant. Typical practice, for both transportation and transmission models, is to calibrate flows in the base case to reflect historic flows (or limits). Depending on the degree of calibration and the changes in flows from the base case to the policy case, this level of calibration may be adequate. That is, it is not a given that revised flows in a policy case would require re-specification of transfer limits that have already been introduced as constraints in the base case. Thus, in short-run studies, the above discussion of calibration and use of hurdle rates may be at least as important as the choice of simulation tools to represent the transmission network.

This discussion of the inherent technical superiority of transmission models over transportation of the network models raises the question of which models are the best to use in an RTO benefit-cost study. We believe this is a miss-leading question. In our opinion, the correct question is whether the simulation tool is appropriate to study the specific issues of concern. For example, in addition to the less-detailed (transportation) and more-detailed (transmission) tools we have already mentioned and that are in use for production-cost studies, there is another type of transmission study tool that is even more detailed: the AC power-flow model, but which is never used for these types of benefit-cost studies. The AC model uses a full nonlinear model to account for voltage, voltage limits, reactive power, and reactive power limits on generation and transmission-line usage. The linearized DC model,[12] which is used in the detailed transmission-modeling studies we reviewed (e.g., GE-MAPS, Promod IV), neglects these effects and focuses only on active power. Therefore, linearized DC models tend to overestimate production-cost benefits (by allowing more trade) compared to AC models (similar to the way transportation models tend to overestimate these costs compared to linearized DC

[12] DC denotes "Decoupled," not "Direct Current." This is an unfortunate and confusing choice of terminology. The model is decoupled in the sense that the active power and voltage phase-angle relations are decoupled from reactive power and voltage magnitude relations using engineering approximations, and then the latter are dropped from the analysis. In addition, the engineering approximations include a linearization to achieve a simple and mathematically tractable model for active power.

models). Despite these issues, we do not suggest that more detailed tools are always appropriate for answering the questions we seek to address regarding the benefits of RTO formation, for the reasons outlined in the following paragraphs.

First, the extent to which the linearized DC formulation is employed in the more detailed transmission models (and thus the technical advantage or improvement in accuracy of these models over the transportation models) is not always clear. Full utilization of the linearized DC formulation would involve treating each simulated load separately by dynamically recalculating limits for each modeled path for each hour and redispatching generation as needed. However, limits are typically recalculated in transmission models only once for an entire year or season based on a single case (e.g., the summer peak hour). Thus, from the standpoint of the year-long hourly production-cost simulation, there may be as few as two one-hour calibrating runs in which electrical network effects are explicitly taken into account (once for the base-case summer peak hour and once for the policy-case summer peak hour). With limits set in this manner, the effect of the production-cost algorithms for the remaining hours of the year may not be significantly different in the transmission and transportation models.

Second, and perhaps more important, the complexity of the detailed transmission tools appears to limit their practical application to single-year studies. Or, in other words, the additional uncertainties introduced when their application is extended to multi-year studies may outweigh the potential technical advantages. Referring to Table 3.2, we see that, in practice, the multi-year studies listed there were conducted using transportation models and the single-year studies were conducted using transmission models. This is understandable. As we will discuss in Section 4, the multi-year studies make it possible to examine differences in generation and transmission infrastructure investments between base and policy cases, in contrast to single-year studies, which hold these investments fixed between the two cases. It is much easier in principle to use more detailed transmission models to study production-cost changes while holding these investments fixed because doing so simplifies the subtle assumptions inherent in treating dynamic flow capabilities of the network (e.g., the relevant list of contingencies that is sometimes considered in power-flow studies would change for each different portfolio of generation and each different transmission topology).

Recommendations for future studies: 1) Describe representation of transmission network capabilities used by study tools; 2) Discuss implications of choice of study tool (and its representation of transmission network) on findings, including likely biases or significance of uncertainty that is introduced.

3.3.4 Reliance on Reported Generator Production Costs

Production-cost simulation tools were originally developed to support generation planning by vertically integrated utilities. As a result, the tools assume that the variable cost of production is known. When these tools are used to study restructuring policies, this assumption becomes problematic because, under most restructuring scenarios, generators are expected to offer power in the formal wholesale market at the prices they believe will maximize their profits. In an idealized (i.e., perfectly competitive) restructured market, these offers are expected to reflect a generator's true variable cost of production. Whether this expectation is realized depends on how closely the actual market's performance matches the idealized performance.

The studies we reviewed relied on public and private sources to derive generator-cost offers that are assumed to be equal to the variable cost of production. The variable cost of production is usually specified in several parts: a) heat rate in British Thermal Units per kilowatt hour (BTU/kWh); b) fuel cost ($/BTU); and c) variable O&M costs ($/kWh). Items a) and c) are taken from historical information reported by generators and are held fixed for the study period. In Section 4, we will discuss in detail the lack of empirical research on the extent to which historical engineering performance of generators is likely to persist in the future. Item b) is allowed to vary, based on a forecast of the future cost of fuel. The issue of long-term contracts discussed previously (in this case, the contracts would be for fuel, rather than for electricity, but the issues remain the same) and consistency among the forecasts themselves are two major sources of uncertainty.

Of greater importance for the studies is the implicit assumption that restructured markets will elicit generator offers that reflect only the effects of these technical factors on the cost of production. The main reason that this assumption may be erroneous is the extent to which the restructured market will provide (unintended) opportunities for generators to abuse market power.

With one exception (TCA 2002), none of the studies we reviewed attempts to quantify the potential for market power. In all reports, the production-cost benefits are reported based on the assumption of competitive, marginal-cost-of-production offers. In TCA (2002), a separate side calculation of relative market concentrations suggests that there is significant potential for market power in the northwest. Many reports comment on the potential adverse effects of market power and note specifically that these effects could detract from the calculated benefits. Accordingly, we submit that it is reasonable to think that the benefits determined by production-cost simulations are overestimated if there is any level of market power exploitation. That is, shifts in dispatch that results from exploitation of market power will tend to lead to a solution that is different from least-production-cost dispatch, which will tend to decrease the total benefits. It will also likely also increase the wealth transfer from consumers to producers.

Tools have not yet been developed that would allow us to simulate the behavior of generators responding to competitive opportunities created by the design of wholesale markets within a network topology that might confer locational advantages to them. Currently, there is an enormous gap between academic treatment of these topics and practical application of them to transmission-planning studies. The California ISO Transmission Economic Assessment Methodology is an early notable effort (CAISO 2004). However, it is not realistic to expect RTO studies, in the near term, to do much more than acknowledge these potential problems while continuing to use traditional production-cost simulation methods.

Table 3.3 RTO Costs

Study	Costs	Notes
PJM 2002	Not estimated as part of study scope	
ICF 2002	Start-up costs range from $1.0B/yr to $5.8B/yr. Operating costs not estimated.	Start-up costs estimated based on extrapolation from recent operating experience of ISOs.
TCA 2002	Annual operating costs are $130 to $140M/yr, including the amortized start-up costs of the RTO.	B/C ratios are > 2.
ESAI 2002	Not estimated as part of study scope.	
ISO-NE/NYISO 2002	Net implementation costs range from $120 to 220M. Net changes in operating costs are negative and included as benefits.	Detailed implementation and operating cost elements considered B/C ratios are > 2, considering only organizational benefits.
CRA 2002	Start-up costs are $530M and $700M w/o SMD and w/ SMD, respectively. Annual operating costs are $150M/yr and $200M/yr w/o SMD and w/SMD, respectively.	Both RTO costs and "other transmission costs" are considered (B/C ratio < 1).
DOE 2003	$1.5B/yr annual revenue requirement.	Incremental cost of SMD is approximately 50% of annual revenue requirement (B/C ratio ~2).
CERA 2003	Not estimated in study.	
SAIC 2004	RTO costs plus congestion costs are $54M/yr.	B/C ratio is ~2.
CRA 2004	PJM admin. charge is $240M/10yr.	B/C ratio is > 3.
Henwood 2004	$200M/yr.	Costs developed from detailed review of RTO cost reports (Lutzenhiser 2004) B/C ratio is < 1.

Recommendation for future studies: Conduct sensitivity studies that directly account for possibility and impact of market power abuse by generators (e.g., adding a dynamic price premium on top of variable production costs for generators in load pockets). This could lead to greater awareness and appreciation of the significance of potential problems and help define the value of efforts to address them. It could also help identify promising approaches to detection and assessment of market-power abuses in actual operations (e.g., to identify load pockets, estimate likely mark-ups).

3.4 The Costs of RTOs vs. the Cost Impacts on Other Market Participants

The main costs considered in the benefit-cost studies we reviewed are start-up and ongoing operating costs for RTOs. Table 3.3 presents the cost estimates and, consistent with the treatment of production- costs and benefits presented earlier, normalizes them to enable direct comparisons among them.

Since the time we began this review in the fall of 2004, two studies have been published that speak to the major issues we found in our review. Lutzenhiser (2004) compiled costs reported by existing ISOs and RTOs, and FERC (2004) estimated so-called day-one and day-two costs, based on a detailed functionalization of reported RTO start-up and operating costs. We start with these more recent studies in our review.

Early studies of RTOs had to hypothesize RTO start-up and operating costs, but recent studies have begun to incorporate actual cost information reported by existing ISOs and RTOs. Henwood (2004), for example, incorporates information from Lutzenhiser (2004) in assessing the cost of an RTO in the Pacific Northwest.

Generally speaking, the costs estimated for RTO start-up and ongoing operations are of the same order of magnitude as those estimated for the short-run economic efficiency gains resulting from RTO formation. In addition, benefits are typically found to exceed costs, leading to preliminary conclusions that formation of RTOs would lead to net benefits. The ratios of benefits versus costs hovers around 2; i.e., the benefits are twice the magnitude of the costs.

Regardless of the original source, there are three issues to keep in mind when looking at these cost estimates: 1) comparability of the functions included, particularly the treatment of unique or non-transferable aspects of costs from one region in the hypothesis of likely costs for another region; 2) the potential for higher (or lower) efficiency in providing a given functionality in another region/RTO setting; and 3) the time period over which start-up costs are amortized.

FERC (2004) attempted to address the first issue in its recent study by seeking to functionalize cost elements in order to ensure greater comparability. Greater uniformity and consistency will certainly improve future assessments of these costs.[13]

[13] During the final stages of preparation of this report, FERC issued order 668, Accounting and Financial Reporting for Public Utilities Including RTOs (FERC 2005), which further addresses this issue.

The baseline issue mentioned in the previous subsection is also germane here: one might expect lower incremental costs on a percentage basis going from established RTOs to a single, large "super RTO," compared to the costs for establishing an RTO where none previously existed. We find limited evidence of this trend in the early studies that consider this scenario but do not discuss the issue of costs (PJM 2002 and ESAI 2002) or that consider only start-up costs and do not estimate incremental changes in operating costs (ICF 2002 and ISO-NE/NYISO 2002).

Finally, although the studies we reviewed focus on the direct costs associated with RTO formation and operation, they generally do not explicitly treat cost impacts on other market participants or regulatory agencies (Morey, Eakin, Kirsch 2005). On the one hand, transferring operational responsibilities formerly undertaken by separate utilities and centralizing them within an RTO may lower overall costs.[14] On the other hand, market participants (both buyers and sellers, as well as regulators) may face new costs as a result of the creation of new market institutions. We can reasonably assume that these costs will be included the cost of power offered and delivered to consumers. If this assumption is accurate, it may be possible, in principle, to capture these costs through cost adders in production-cost studies. However, we are not aware of studies that have considered these issues in detail.

Recommendations for future studies: 1) Discuss functional and empirical basis for RTO cost estimates, 2) Discuss cost impacts on all stakeholders.

3.5 Summary and Recommendations for Improving Future Production-Cost-Simulation-based Studies

Taken as a group, the 11 benefit-cost studies that we reviewed document the evolution of the policy dialogue about RTO formation. These studies rely primarily on production-cost-simulation methods to estimate the short-run efficiencies that might result from centralized dispatch by an RTO over a larger geographic footprint than is currently covered by individual utilities. These efficiencies are generally but not always found to be greater than the expected incremental costs of forming and operating an RTO. In recent studies, these incremental costs are based on analyses of the operating experience of current RTO/ISOs. The majority of the studies conclude that formation of an RTO is cost effective; however, these conclusions are drawn from the modest magnitude of and narrow range between the expected benefits and costs that been considered to date, and the uncertainties in the data and methods used in these studies may be comparable in magnitude to the impacts that have been estimated. This should be cause for concern; we should avoid attributing great significance to the numerical results of these studies until we have a better understanding of these uncertainties.

[14] In fact, none of the studies estimated operating cost reductions for the utilities or organizations previously providing the services or functions assumed by the RTO.

We expect that future studies will be conducted to examine the costs and benefits of proposed RTOs and that the methods and data employed will continue to build from those used in the studies we analyzed. To help improve future studies, we conclude this section with a summary list (Table 3.4) of the numerous recommendations we have made throughout our review. This list is intended to help improve the consistency and transparency of future assessments based on production-cost simulation methods.

Table 3.4 Recommendations for Improving RTO Benefit-Cost Studies Focused on Short-term Economic Efficiency Impacts

Study Element	**Recommendations**
Baseline and Policy	Clearly articulate assumed base-case conditions and changes assumed for policy case. Provide rationale for assumed changes in policy case(s)
Benefit-Cost Perspectives	Present and identify benefits and costs inclusively from a wide variety of perspectives. Clarify differences between transfers among market participants (and articulate the mechanisms by which they take place) and real changes in total societal costs.
Long-Term Contracts	Describe treatment of long-term contracts and "grandfathered" transmission agreements.
Hurdle Rates	Discuss (and present numerical results from application of) calibration standard and other "tuning" mechanisms (e.g., transmission-path rating assumptions), including influence of these choices on examination of policy in question. Provide rationale for hurdle-rate adjustment in policy case. Discuss treatment of hurdle-rate changes in various benefit-cost perspectives.
Transmission Network	Describe representation of transmission network capabilities by study tools. Discuss implications of choice of study tool (and its representation of transmission network) on findings, including likely biases or significance of uncertainty that is introduced.
Generator Offers	Conduct sensitivity studies that directly account for possibility and impact of market power abuse by generators (e.g., adding a dynamic price premium on top of variable production costs for generators in load pockets).
Cost of FERC Policies	Discuss functional and empirical basis for RTO cost estimates. Discuss cost impacts on all stakeholders.

4. Expanding the Scope of Future RTO Benefit-Cost Studies

A broad scope of impacts is considered by the original FERC-commissioned studies of FERC electricity restructuring policies when these policies were first articulated (as summarized in Section 2 above). A much more limited set of impacts has actually been considered by recent benefit-cost studies (as summarized in Section 3 above). This disparity makes clear that many of the expected impacts of FERC's policies have yet to be examined in detail.

Future assessments of benefits and costs of FERC policies would be much more comprehensive than existing studies if they addressed the benefits and costs of:

1. Reliability Management,
2. Generation and Transmission Investment and Operation, and
3. Wholesale Electricity Market Operation.

Addressing these additional issues would produce a more complete assessment of the expected benefits and costs of FERC's policies than has been attempted to date.

The three areas listed above are especially important to address in future inquiries because they may be of greater significance than the impacts have been considered to date. Failure to consider the above impacts will perpetuate an incomplete picture of the total impact of FERC's policies.

Earlier studies should not be criticized for failure to consider these additional areas of impact, because for the most part neither data nor methods yet exist on which to base definitive analyses. At the same time, it is important to understand that we are now in a period of transition from analyses that were necessarily prospective and hypothetical to a period in which analyses can be retrospective and based on empirical evidence. The latter approach should become the standard for assessing the impacts of FERC's policies. The primary objective is not simply to improve individual future RTO benefit-cost studies but to establish a more robust empirical basis for ongoing assessment of the electricity industry's evolution.

Accordingly, in this final section of the report, we focus on identifying the challenges in building from the current generation of studies to more comprehensive future assessments that address the additional areas of impact listed above.

4.1 Reliability Management

Reliability management, for the purposes of our discussion, refers to short-term activities to ensure reliability, which the North American Electric Reliability Council (NERC) defines as adequacy and security.[15] Reliability activities involve management of a static fleet of generation and transmission assets to meet ever-changing electricity demands in the face of both planned and unplanned unavailability of individual generating and

[15] We address the longer-term aspects of reliability adequacy in Section 4.2.

transmission assets. These activities include, but are not limited to, scheduling and coordinating maintenance of assets; planning day-ahead operations (including securing adequate reserves) and actual operations in real-time (including supporting interconnection frequency); maintaining voltages; and responding to contingencies as they occur.

RTO formation might affect these aspects of reliability management in two ways: First, the cost of managing reliability may change as result of economies of scale that might be captured by an RTO. This aspect of RTO operation has been addressed to a limited degree by some recent benefit-cost studies. Second, the quality and scope of reliability management within and among regions might change under an RTO. This aspect has been only mentioned by recent studies. It raises a fundamental challenge that stems from the current formulation of reliability rules and also points to a broader methodological evaluation challenge that future studies will need to address.

Measuring changes in the costs of managing reliability has two elements that have been addressed to varying degrees by the studies reviewed in Section 3. First, the administrative costs of managing reliability are included in the start-up and operational costs of an RTO, discussed in Section 3.4 where we note that a few studies consider and none suggest that there would be net cost reductions as a result of centralized provision of these and other administrative functions by an RTO. However, reliability management is not considered directly in these studies. Second, the cost of procuring reliability services, such as operating reserves, is just an extension of the benefits that can be estimated using production-cost-simulation approaches to replicate the effects of centralized dispatch over the RTO's geographic footprint. Several studies consider these production-cost impacts in their assessments (TCA 2002, ISO-NE/NYISO 2002, Henwood 2004).

The more elusive aspects of reliability management that might change under an RTO are the quality and scope of the management activities themselves. A key challenge is that major outages are comparatively rare events. Several studies suggest that reliability management will be improved under an RTO because an RTO will have greater visibility of and easier opportunities to redispatch resources over a larger footprint than was overseen by the entities that make up the RTO. However, no studies attempt to quantify this effect in terms of improvements in reliability. (See Text Box.)

Failure to consider the impacts of RTOs on these aspects of reliability management is a major shortcoming of recent studies because of the potential magnitude of these impacts may be large. Power interruptions are estimated to cost the U.S. approximately $90B annually (Hamachi-Lacommare and Eto 2004). While most of the initiating events for these interruptions originate on utility distribution systems, reducing (or increasing) these costs by even a small fraction would be significant and comparable in magnitude to the economic savings estimated by the studies review in Section 3. An even more dramatic example is the estimated economic damage from the August 14, 2003 Northeast Blackout, which range from $5-10 B (U.S.-Canada Task Force 2004). The fact that

MISO Market Operations Have Reduced TLR Activities in the Midwest

Historically, Transmission Loading Relief (TLR) activities initiated by the MISO reliability coordinator have ranked among the most active of all Eastern Interconnection reliability coordinators. In addition, the severity of the TLRs called by MISO has routinely been a mix of the low and high levels provided for by NERC's operating procedures.

Following the opening of the MISO market in April 2005, the severity mix of TLR's called by MISO has dramatically shifted to lower priority uses of the system. In other words, TLR's, when they are called, affect primarily non-firm transmission requests. These reductions can be attributed to the operation of MISO's market to anticipate and resolve potential conflicts between planned transactions and safe operating limits long before real-time operations. Moreover, the resolution effected by these market operations improves the economic utilization of the available transmission network.

TLR is a real-time operating procedure that allows reliability coordinators to mitigate potential or actual violations of reliability limits (called operating security limits). The need for TLR's arises primarily when transaction schedules are not well-coordinated among multiple control areas in advance of real-time operations. In-adequate coordination leads to situations in which one or more flowgates become overloaded in real-time. Calling a TLR allows the reliability coordinator to initiate a pre-determined sequence of curtailment and re-dispatch actions intended to reduce transaction flows to a safe (or secure) operating level. The scope of actions allowed depends on the severity of the TLR called. More severe TLR's mean that firm transmission service requests can become candidates for reduction; less severe TLR's primarily affect non-firm transmission service requests.

A recent, internal review by MISO staff finds that monthly TLR activity levels (numbers of TLR's called) are consistent with past history (MISO 2005a). However, detailed review of the TLR logs reveals that the mix of TLR's called has greatly shifted to curtailments of lower severity. Discussion with MISO staff confirms that, as a result of centralized dispatch, TLR calls to reduce flows within the MISO footprint have been dramatically reduced (MISO 2005b). TLR calls, nevertheless, remain significant at seams between MISO and its neighboring areas.

Within the MISO footprint, the centralized market operated by MISO, via the posting of locational marginal prices, sends market signals that reveal the severity of congestion at locations within the footprint. These price signals allow generators and loads to voluntarily undertake actions both long in advance and in real-time re-dispatch in order to avoid (or minimize the severity of) the congestion that lead to the need for TLRs in real time (and the involuntary actions they compel).

Reliance on market signals to initiate these actions, moreover, enables an economic response by both the generator and the loads that are affected. As a result, economic utilization of available transmission capability is improved.

recent studies do not take potential impacts of this magnitude into account reinforces the conclusion that these studies do not give a full picture of RTO benefits and costs.

The first complication in addressing these reliability benefits and costs is that there is currently no graduated standard for assessing degrees of reliability performance among organizations other than the binary standard of compliance or non-compliance with NERC reliability rules. Moreover, it is difficult to correlate individual findings of non-compliance with NERC rules to the relative risks that each finding of non-compliance poses to the reliability of operations.

The second complication is that there can be differences of opinion regarding the relevant basis for comparing reliability management before and after formation of an RTO. If the beneficial aspects of reliability management stem mainly from the size of an organization's geographic footprint, then these impacts cannot be uniquely attributed to formation of an RTO because there are many examples of reliability management organizations in North America that have large geographic footprints but are not RTOs. Nevertheless, if size does matter and forming an RTO is the only practical means to consolidate reliability-management activities that would otherwise be dispersed among many smaller entities in a region, then it is reasonable to attribute the ensuing reliability impacts to the RTO.

Addressing reliability impacts requires the development of reliability metrics and the collection of relevant data over time. More RTO studies cannot, by themselves, improve on the current situation. Recently revised NERC standards should be the starting point for this research, and the research should be undertaken for all organizations with real-time reliability management responsibilities, not just for current RTOs.

4.2 Generation and Transmission Investment and Operation

As previously noted, the RTO benefit-cost studies prepared to date focus mainly on short-term production cost savings realized as a result of more efficient dispatch, under an RTO, of a static fleet of generation and transmission assets. However, the original studies of FERC's orders also envisioned significant long-run changes in generation and transmission investment, including the introduction of advanced technologies as well as enhancements or improvements to the efficiency of the assets themselves (e.g., improvements in generating efficiency). By and large, these impacts have not been analyzed in recent studies even though many observers believe that these impacts are significant. As is the case with reliability management, explicit consideration of these impacts is essential if we are to make a balanced assessment of the overall impacts of FERC's policies. For example, the largest economic impact reported in FERC (1996) – larger than the short-run economic efficiencies expected through improved dispatch – is reduction in fixed O&M costs, which has not been assessed by any of the studies we reviewed.

For the most part, generation and transmission assets are held fixed in both the base case and the policy case in the studies we reviewed. In studies that assume that the fleet of assets changes over time, the changes are generally based on previously announced plans. Two studies that consider multi-year time horizons (ICF 2002 and ESAI 2002) allow for capacity expansion beyond announced plans, usually based on a maintaining a static reserve margin, given a load forecast. Nevertheless, in part because the load forecast is held fixed, the fleet (both in terms of capacity and fuel source) also remains unchanged between the base and policy cases.

Three studies consider operational enhancements in generator efficiency and improvements in transmission capability as part of the policy case or as a sensitivity case (ICF 2002, PJM 2002, and DOE 2003). ICF (2002) assumes that: transmission capability will increase by five percent from 2004 onward; 100 percent vs. 75 percent of transmission capability will be accessible; reserve margins will decline to a system-wide average of 13 percent by 2020; and fossil-fuel generation heat rates will improve by six percent by 2010 and unit availability will increase by 2.5 percent. PJM (2002) considers sensitivity cases in which transmission capability is increased among regions (possibly as a result of investment in static-VAR compensation devices and as a result of optimizing the operation of phase-angle regulators). DOE (2003) assumes that coal units will be two percent more efficient and gas steam units will be four percent more efficient over five years, and that transmission capability will increase by five percent.

The key shortcoming of these initial efforts is that the findings are driven principally by *only* the above assumptions, which cannot be verified independently. The direction of the hypothesized changes is logical or at least consistent with conventional wisdom regarding the expected impacts of increased competition, but the magnitude of the expected changes is essentially speculative.

To date, practice clearly outweighs theory as a basis for understanding how recent FERC policies individually or as a group (along with the many other changes that have taken place in the industry) have affected and will affect the operation and investment in generation and transmission assets. Recent appearance of academic analyses - conducted independent of formal RTO benefit-cost studies - are noteworthy for explicitly relying on empirical information and for rigorously controlling for many influences that could otherwise skew their findings. (See Text Box.)

Accordingly, we recommend increased collection and systematic analysis of empirical information on generation and transmission investment and operating efficiencies. We should proceed based on the recognition that we are moving from analyses that are necessarily prospective and hypothetical to analyses that can be retrospective and should be empirically based. The latter should become the focus of future efforts to assess the impacts of FERC policies. The primary objective is not simply to improve individual future RTO benefit-cost studies but to establish a robust empirical basis for ongoing assessment of the evolution of the electricity industry.

The Impacts of Restructuring on Generator Performance

Promising efforts to improve the empirical base upon which assessments of the impacts of restructuring on generator performances are starting to emerge. Markiewicz, Rose, and Wolfram (2004) analyze operating data from generating plants, collected between 1981 and 1999, to examine changes in non-fuel expenses and employment. Using econometric techniques, they find larger cost efficiencies in plants operated by investor-owned utilities in restructured markets than in those operated by investor-owned utilities in un-restructured markets (five percent) and in those operated by municipal-federal-cooperative utilities (15-20 percent). More recently, Bushnell and Wolfram (2005) find two-percent improvements in fuel efficiency in plants that have been divested compared to those that have not been divested and that continue to operate under traditional cost-of-service rate regulation.

Studies such as these are noteworthy for their explicit reliance on empirical information and for the analytical rigor with which they control for the many influences that could skew their findings. They also point to the difficulty of seeking to determine too precisely the influence of individual FERC policies. For example, Bushnell and Wolfram (2005) observe that fuel efficiencies in non-divested plants operating under incentive rate regulations are similar to the efficiencies in plants that have been divested. This study also does not distinguish between plants operated in ISO or RTO markets and those operated outside of these markets. In view of the many influences of different FERC policies on generation and transmission investment and operation, it may not be feasible to definitively isolate the influence of individual policies in analyses of actual investment and operating data. The difficulty of distinguishing the effects of different FERC policies must be kept in mind whenever we discuss what can and should be expected from future analyses of empirical information related to RTO benefits and costs.

Existing Energy Information Administration (EIA) and FERC data-collection activities should be reviewed and revised with the above objectives in mind.[16] Special attention should be paid to the role of RTOs, ISOs, and other regional entities as vehicles for the regional transmission planning that is an essential enabler for these investments. EIA has also reached this conclusion and initiated this process (EIA 2004). Topics that need attention include on FERC Form 1: 1) Consistent separation of transmission from distribution and identification of costs, revenues, and net capital stock and investment, using NPIA definitions of investment; and 2) Specific identification of investments in the high-voltage grid, including related computation, communications, and metering devices.

[16] During the final stages of preparation of this report, FERC issued order 668, Accounting and Financial Reporting for Public Utilities Including RTOs, which addresses this recommendation (FERC 2005).

4.3 Wholesale Electricity Market Operation

A distinguishing feature of ISOs and RTOs is that they support formal, public, wholesale spot markets for electricity. Prior to electricity industry restructuring, short-term wholesale trades were negotiated bilaterally between utilities through private transactions. Price discovery by outside parties in those situations was difficult at best. Formal markets, in contrast, reveal publicly the price of wholesale electricity transactions. Publicly posted prices can reduce the cost of price discovery and improve the credibility of pricing information, thereby facilitating the creation of financial instruments, such as forward contracts, to more effectively manage price risks. Improved risk-management practices should, in principle, lead to lower electricity costs. In addition, these practices enable formal participation in wholesale markets by customers as well as generators and load-serving entities, which can improve both market efficiency and system reliability. Formal public (as well as informal private) markets, however, may be susceptible to market manipulation and the exercise of market power, which may distort prices and erode the markets' credibility.

Despite the central role that formation of competitive wholesale markets for electricity has played in FERC's recent policies, especially its policies on RTOs, the studies we reviewed focus only competitive-market impacts related to efficient dispatch; no other impacts of market formation are addressed. This is a major shortcoming. Many observers believe that formal markets are essential for enabling and supporting risk-management strategies that directly influence the nature and pace of future investments in generation and transmission. They also point out that RTOs are not unique in their ability to support the formal wholesale markets. With or without an RTO, understanding the role of wholesale electricity markets ought to be a critical element in our understanding of the role of FERC policies in influencing these investments. This element is, as yet, missing in benefit-cost analyses of RTOs.

A handful of the studies we reviewed touch on limited aspects of the possible influences of FERC's policies on markets. ICF (2002), ESAI (2002), and DOE (2003) all consider demand response in their assessments. These studies focus mainly on the role of demand response in moderating wholesale electricity prices by introducing demand price elasticity into markets that are currently essentially price-inelastic. DOE (2003) also considers the role of demand response as a system reliability resource, measuring the value of demand response by the value of (what might otherwise be) lost load.

As mentioned in Section 3.3.4, TCA (2002) is the only study that directly considers the potential for abuse of market power by generators. As evidenced by the problems that California faced in 2000-2001, neglecting to address this potential is very risky. The possible costs of market-power abuse could, like the costs of a large-scale blackout, easily exceed the generation dispatch benefits that have been considered by the studies we reviewed.

Improving on this situation will be difficult. As is the case for generation and transmission investment and enhancement, data on market-power abuse are scarce, and robust theoretical constructs and methods for rigorously assessing these data are in their infancy. FERC market-monitoring efforts have started addressing this issue but are focusing only on existing RTO markets. Detailed, comprehensive data collection should be undertaken, starting with data on: new entry, generator access and service denial, costs and qualities of transmission service available to generators, congestion costs, curtailment volumes and frequencies, power flows (trade) across regions, and the corresponding price differentials. Data confidentiality issues must be addressed. (See Text Box.)

Energy Information Agency Recommendations for Improved Data Collection on Transmission and Wholesale Power Markets

The changing structure of the industry and the Federal Government's increasing interest in transmission prompted EIA to reexamine current official data collections to determine whether they continue to meet the needs of the Government. EIA's report, *Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis* (EIA 2004), identifies transmission information relevant to three broad national policy interests:

- Reliability and National security;
- Economic regulation; and
- Economic growth and efficiency.

In the area of transmission and wholesale power markets, EIA finds that much of the data needed to evaluate the grid's support of markets is already being collected. The data are not, however, available for policy analyses. Outside the ISOs the Government "does not have the data necessary to monitor and evaluate the competitive status of wholesale markets." The report goes on the make recommendations to improve this situation.

Financial and Investment Data: Possible Changes to Existing Forms

Information Need	Form	Needed Changes	Comment
1. Consistent separation of transmission from distribution accounts.	FERC 1, EIA-412	Explicitly define transmission in the same way for all utilities and use that definition in assigning costs, revenues, and net capital.	Current data are an "apples and oranges" mix.
2. Utility investment in the high-voltage grid.	FERC 1, EIA-412	1. Adopt NIPA definition of investment. 2. Report line and associated equipment investment by voltage level. 3. Report investment in metering, communication, software, and control of the high-voltage grid.	Current "additions to plant and equipment" data have very limited use for economic and reliability analysis, although they are important to capital cost recovery.
3. Independent power producer (IPP) investment.	EIA-860	Collect direct connection and grid reinforcement costs from IPPs on EIA 860.	Some of these investments may not be picked up on FERC Form 1. See Chapters 3 and 4.
4. Merchant transmission investment.	EIA-412	Add to the list of respondents and require them to report transmission investments, as defined above, and to fill out Schedules 10 and 11.	Merchant investment and line data are not currently collected.
5. Ancillary service revenues.	FERC 1, EIA-412	Require reporting as proposed by FERC.	
6. Re-dispatch costs.	FERC 1, EIA-412	Require reporting.	Only applicable to utilities owning generators. Not necessary for ISOs.
7. Regional costs.	FERC 1, EIA-412	Require reporters to disaggregate cost, revenue, net capital stock, and investment by appropriate region.	This would allow regional cost comparisons.
8. Consistent aggregation.	EIA-412	Adopt FERC definitions (see above) and require reporting by calendar year.	EIA currently allows reporting by fiscal year.

Source: EIA. 2004.

4.4 Summary

Our review of recent benefit-cost studies finds many uncertainties and unexamined impacts. These uncertainties and omissions mean that it is not possible at this time to definitively assess FERC's RTO policies. Although technical improvements in the traditional production-cost methods used to conduct the studies that we reviewed will be helpful at the margin, we believe that future assessments should be devoted to studying impacts that have not been adequately examined, including reliability management, generation and transmission investment and operational efficiencies, and wholesale electricity markets. See Table 4.1. The potential benefits (and costs) associated with these as-yet incompletely studied impacts could easily outweigh the limited benefits and costs that have been studied to date. Failure to consider these impacts results in an incomplete and potentially misleading picture of the total impact of FERC's policies.

Table 4.1 Recommendations for Additional Topics That Should be Included in Future RTO Benefit-Cost Studies

Study Elements	Recommended Areas of Focus
Reliability Management	The total cost of managing reliability within and among regions under an RTO. The quality and scope of reliability management activities within and among regions under an RTO, including establishing a baseline.
Generation and Transmission Investment and Operation	Generation and transmission investment, including role of regional planning. . Generation operating efficiency (heat rate, fixed and variable O&C costs) and availability. Transmission capability, congestion management.
Wholesale Electricity Market Operation	New entry. Generator access and service denial. Cost and quality of transmission service available to generators. Cost of congestion, volume and frequency of curtailment, flow of power (trade) across regions, and the price differentials that correspond to these factors. Role and impact of demand response.

Systematic consideration of these impacts is neither straightforward nor possible without improved data collection and analysis methods. We are hopeful that this review will contribute to advancing the development of the necessary data resources and analysis methods and the preparation of studies to address the impacts that have not yet been evaluated.

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