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

Definitive assessment of Federal Energy Regulatory Commission policies on regional transmission organizations is not currently possible because of uncertainties in the data and methods used in recent benefit-cost studies as well as lack of investigation of key impacts of the formation of RTOs.

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I. Introduction

During the past four years, government and private organizations have issued more than a dozen studies of the benefits and costs of wholesale electricity competition. Recent studies have focused on the formation of regional transmission organizations (RTOs).[1] Many of these studies use simulation techniques to estimate benefits in the form of production-cost savings resulting from greater centralized dispatch under an RTO compared to less centralized dispatch without an RTO. These benefits are compared to estimated costs for RTO startup and operation. Generally, but not always, the studies find that the production-cost savings are greater than the costs of forming and operating an RTO. Compared to total production-costs,

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however, the differences are modest, on the order of a few percent.

We reviewed recent studies of RTO impacts and identified two areas of concern:

(1) **Significant uncertainties in the data and methods used to estimate benefits and costs.** Because of the narrow margin between benefits and costs, we recommend that future simulation-based studies more consistently discuss key elements, including: (a) the benefits and costs examined (and not examined) and the perspectives from which they are considered; and (b) the choice and use of study tools, including how tools are calibrated and how they are used to represent the effects of the policies under consideration. Consistent discussion of these elements will increase confidence in study results by clarifying what is and is not represented in each study.

(2) **Absence of treatment of entire categories of RTO impacts, resulting in systematic understatement of both benefits and costs**. The impacts of RTO formation on reliability management, generation and transmission investment and operation, and wholesale electricity market operation are either not considered at all or are not quantified in recent studies. This is a major shortcoming. If these impacts are not studied quantitatively, then for all intents and purpose they are treated as if they are equal to zero. Omitting these impacts is misleading. Assessment of the effect of FERC's electricity restructuring policies is incomplete if these impacts are not addressed.

The remainder of this article briefly reviews the main features of the RTO studies we reviewed, describes elements that should be addressed more systematically in future studies, and discusses the challenges of addressing RTO impacts that have not been studied quantitatively to date.

The baselines and policies addressed by studies have changed over time. The earliest ones focused on very large RTOs.

II. Overview of Recent RTO Benefit-Cost Studies

In 2005, we reviewed 11 simulation-based benefit-cost studies that were published between 2002 and 2004.[2] Taken together, these studies represent the current state of the art of RTO benefit-cost analysis. As other researchers have noted, these studies primarily consider the tradeoff between *benefits* in the form of short-run production-cost efficiencies and *costs* for the startup and operation of an RTO.[3] The analytical approach compares two hypothetical generation-dispatch scenarios: a ''baseline'' projection of pre-RTO performance and a post-RTO alternative (a.k.a. the ''policy'' case). **Table 1** summarizes the major elements of our review of the 11 studies.[4]

The baselines and policies addressed by studies have changed over time. The earliest studies focused on the potential impacts of FERC's initial policy preference for a small number of very large regional RTOs.[5] One group of early studies examined the establishment of RTOs in areas of the country where independent system operators (ISOs) had not yet formed.[6] Recent studies have focused how parties deciding whether to join an existing RTO would be affected.[7] These more recent studies look at the incremental change resulting from centralized dispatch in the larger RTO footprint that would result from adding new members.

The studies we reviewed use production-cost simulation tools to estimate economic efficiency gains from changes in generator dispatch.[8] The usefulness of these tools in estimating the short-run economic benefits of RTOs can be easily understood in view of the hypothesis that, by virtue of having a larger footprint than individual utilities and providers, RTOs can reduce the total cost of dispatch. The hypothesized savings result from the RTO's ability to draw from a larger and more diverse portfolio of generation options than is available to the smaller entities whose dispatch

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Table 1: Benefits and Costs Examined Quantitatively by RTO Studies

Study	Production-Cost Tool	Study Horizon	RTO Start-Up Costs	RTO Operating Costs	Reliability Mgmt. Costs	G&T Operating Efficiency & Investment	Wholesale Market Impacts
PJM. 2002. *Northeast Regional RTO Proposal Analysis of Impact on Spot Energy Prices*	Transmission	Single year				Assumed	
ICF. 2002. *Economic Assessment of RTO Policy*	Transportation	15 years	Estimated			Assumed	Demand response
TCA. 2002. *RTO West Benefit/Cost Study*	Transmission	Single year	Estimated	Estimated	Operating reserves		Market power
ESAI. 2002. *Impact of the Creation of a Single MISO-PJM-SPP Power Market*	Transportation	10 years					Demand response
ISO-NE/NYISO. 2002. *Economic and Reliability Assessment of a Northeastern RTO*	Transmission	2 years	Estimated	Estimated	Operating reserves		
CRA. 2002. *The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast*	Transmission	5 years	Estimated	Estimated			
DOE. 2003. *Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design*	Transportation and transmission	10 years	Estimated	Estimated		Assumed	Demand response
CERA. 2003. *Economic Assessment of American Electric Power's Participation in PJM*	Transmission	3 years					
SAIC. 2004. *The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets*	Transmission	Single year	Estimated	Estimated			
CRA. 2004. *The Benefits and Costs of Dominion Virginia Power Joining PJM*	Transmission	4 years	Estimated	Estimated			
Henwood. 2004. *Study of Costs, Benefits and Alternatives to Grid West*	Transmission	Single year	Based on actual	Based on actual	Operating reserves		

operations would be subsumed under the RTO.

The assumption underlying this approach is that individual entities within the RTO's footprint do not have the same access to the larger portfolio of generation that the RTO would have. As a result, the sum of these entities' individual costs to dispatch the (smaller) portfolios of generation to which they do have access (to minimize the costs of serving their own loads) is expected to be greater than the costs borne by a single RTO seeking to serve these same loads. Yet, access to remote generation and the cost of access depend on subtleties unique to the choice of production-cost simulation tools and the ways in which these tools are calibrated and represent the effects of greater centralized dispatch.

How the transmission system is represented within a production-cost model plays an important role in the model's estimate of the efficiency of greater centralized dispatch because the transmission system is the network over which re-dispatch is implemented. Models represent the transmission system in two basic ways. Coarse, aggregate tools (such as POEMS, IPM, and ESAI) represent the transmission system using a ''transportation'' model in which the energy-transfer capability of each network path is set independent of other paths. More detailed tools (e.g., GE-MAPS, Powerworld, Promod IV) represent the transmission system using a ''transmission'' model in which the energy-transfer capability of each network path depends, in part, on the loading on other paths within the network.

In addition to the physical transfer limits of the transmission system, hurdle rates are also used to introduce an economic ''friction'' between current, smaller dispatch regions that prevents these regions from individually obtaining the production-cost savings that are promised by the central dispatch of the larger, combined region. Hurdle rates are implemented as an increased cost for transactions that cross the geographic boundaries between regions. Hurdle rates are used when a base case is being prepared to help calibrate the production-cost simulation to a historical pattern of generation dispatch. Hurdle rates are also the principal means of implementing the policy (post-RTO) case; that is, in the policy case, the hurdle rate is reduced or modified from its initial base-case level so that the production-cost simulation tool can find a different (usually lower-cost) combination of generation resources to meet the aggregated base-case loads.

How the transmission system is represented within a production-cost model plays an important role in the model's estimate of the efficiency of greater centralized dispatch.

Two elements are usually held fixed between the base and policy case production-cost simulations: the variable cost of production by each generator and the fleet of generator and transmission assets. None of the studies we reviewed assumed that the variable cost of production by each generator would change between the base and policy cases. Most of the studies also held the fleet of generators and transmission assets fixed between the base and policy cases. In studies that assumed that the fleet of assets would change over time, the changes were generally based on previously announced plans. The studies that considered multi-year time horizons allowed for capacity expansion beyond announced plans. Nevertheless, because load forecasts and reserve margins were held fixed between the base and the policy cases, the generation fleet (both capacity and fuel source) also remained unchanged between these two cases.

Consistent with FERC's original Environmental Impact Statement, studies generally find that improvements in generation dispatch resulting from establishment of an RTO offer modest reductions in total production-costs.[9] Annual savings are projected to amount to less than 5 percent and fall mostly in the range of 1 to 3 percent.

The main costs considered in the benefit-cost studies we reviewed are startup and ongoing operating costs for RTOs. Early studies had to hypothesize startup and operating costs, but recent studies incorporate actual cost information reported by existing ISOs and RTOs.

III. Recommendations for Improving Short-Term Efficiency Estimates in Future Benefit-Cost Studies

Current RTO benefit-cost studies are similar in general approach but differ in their data, assumptions, models, and logic. The data are sometimes incomplete and often proprietary or otherwise unverifiable. Assumptions are rarely tested against data; the sensitivity of results to variations in study assumptions is not revealed. In addition, studies are inconsistent in what they tell readers about the technical details that play a decisive role in determining the results. Adding the results of individual studies to arrive at a national estimate is not possible, nor is it possible to compare efficiency gains among different regions. With the goal of clarifying what future studies of short-term efficiencies do and do not tell us, we recommend more consistent presentation of: (1) the benefits and costs examined (and not examined) and the perspectives from which they are considered and (2) the choice and use of study tools, including how they are calibrated and how they are used to represent the effects of the policies under consideration. Table 2 summarizes our recommendations.

A. Describe impacts on all affected parties

Many 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. 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 policies on specific constituents or stakeholders. However, a focus on only one set of impacted groups to the exclusion of others does not give a complete picture of the impacts of FERC's policies

Table 2: Recommendations for Improving RTO Benefit-Cost Studies Focused on Short-Term Economic Efficiency Impacts

Study Element	Recommendations
Base Case and Policy Case	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
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 introduced by this choice
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
Generator Offers	Conduct sensitivity studies that directly account for possibility and impact of market power abuse by generators
Cost of FERC Policies	Describe functional and empirical basis for RTO cost estimates Discuss cost impacts on all stakeholders

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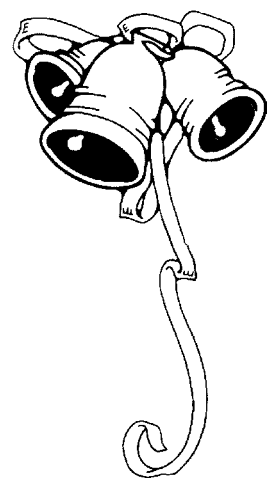
on all affected parties and therefore does not form an adequate basis for evaluating the overall impact of FERC policies.

Benefits and costs are expressed in two main ways in the studies we reviewed: as experienced in a *geographic region* or as experienced by *market participants*. The geographic perspective is by far the most common among the studies we reviewed; this approach describes impacts on parties within defined geographic regions. Impacts outside the immediate study regions are sometimes not considered at all in these studies. The market participant perspective describes impacts on producers separately from impacts on consumers. The majority of studies equate changes in total production-costs with direct benefits to consumers. In some cases, this can be misleading because it ignores or does not address how market-design elements affect the allocation of benefits. 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. Unless impacts on both producers and consumers in both regions are presented, one cannot assess the net impact.

When a study does not address the impacts of a policy on all affected parties, the study misses the opportunity to assess the potential for 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. 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.

B. Discuss adequacy of methods selected to represent transmission constraints

In representing the effect of interregional constraints on electricity exchange, a transportation model will tend to overestimate trade between regions compared to a more detailed transmission model. Calibration of models to reflect historic electricity flows can reduce this effect. The study question and the assumptions required to use either model are as important the choice of which model to use. These aspects of model selection and use should be consistently discussed in all studies of RTO benefits and costs.

We believe that it is misleading to focus on the question of whether a transportation or transmission model is better. In our opinion, the appropriate question is whether the simulation tool is appropriate to study the specific issues being investigated. For example, the complexity of transmission models appears to limit their practical application to single-year studies. The multi-year studies we reviewed were all conducted using transportation models, and the single-year studies were conducted using transmission models. This is sensible. In multi-year studies, it is possible to examine differences in generation and transmission infrastructure investments between base and policy cases. By contrast, single-year studies hold these investments fixed between the two cases. It is less practical to use transmission models to study production-cost changes unless the investments are held fixed (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). In other words, the additional uncertainties introduced when application of transmission models is extended to multi-year

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studies may outweigh the potential technical advantages.

C. Describe calibration of study tools and use of hurdle rates

Hurdle rates play a critical role in benchmarking and in determining the impacts of expanding centralized dispatch. Three aspects of hurdle rates should be documented explicitly in future studies of RTO impacts: (1) calibration of or benchmarking for the base case, (2) specification of changes in hurdle rates for the policy case, and (3) treatment of changes in rates as elements in the benefit-cost calculation.

Only a handful of studies provide numerical, albeit aggregated, information on the results of their calibration efforts, and only one study presents information on the effects of different hurdle rates on calibrations to past power transfers among regions.[10] None of the studies provides an empirically based justification for the reductions in hurdle rates assumed in the policy case. Most of the studies did not clearly document whether or how changes in hurdle rates were treated in the benefit-cost analysis.

Currently, there are no standards for specifying and calibrating or benchmarking the base case to historic dispatch. For that matter, there is no information on the extent to which such calibration is meaningful in examining future dispatch. In addition, there is no readily analyzable empirical information on the changes in generation resulting from expanded 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.

Assessing the degree to which hurdle rates represent true societal costs involves a host of subtle issues that merit further investigation. These issues 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.

D. Discuss representation of market offers using generator production-costs

Production-cost simulation 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, public 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 benefits from centralized dispatch determined by production-cost simulations will be overestimated if there is any level of market power exploitation. That is, shifts in dispatch that result 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 total benefits. It will also likely increase wealth transfers from consumers to producers. In all of the studies we reviewed, production-cost benefits are reported based on the assumption of competitive, marginal-cost-of-production offers. One study that presented a separate side calculation of relative market concentrations suggests that the potential for exercise of market power under an RTO is substantial, but these findings were not employed to change the variable cost of generation used in the production-cost simulation.[11]

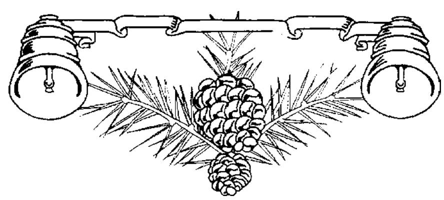
Tools have not yet been developed that would allow us to simulate the behavior of actual generators responding to competitive opportunities created by the design of wholesale markets within a network topology that might confer locational advantages to generators. Currently, there is an enormous gap between academic treatment of these topics and practical application of them to transmission-planning studies. The California ISO Transmission Economic Assessment Methodology is a noteworthy early effort to address this issue.[12] However, it is not realistic to expect RTO studies, in the near term, to do much more than acknowledge this potential problem while continuing to use traditional production-cost simulation methods.

E. Discuss cost impacts on all market participants

Although the studies we reviewed focus on direct costs associated with RTO formation and operation, they generally do not, as noted previously,[13] explicitly treat cost impacts on other market participants. On the one hand, centralizing within an RTO the operational responsibilities formerly undertaken by separate utilities may lower overall costs.[14] On the other hand, market participants (buyers, sellers, regulators) may face new costs because of the creation of new market institutions. We can reasonably assume that these latter 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 have not found studies that consider these issues in detail.

IV. Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies

A broad scope of impacts was considered by the original FERC-



commissioned studies of electricity restructuring policies when these policies were first articulated.[15] FERC wrote "...competition will create benefits through better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion. Staff estimates only the first quantitatively, but based on the experience of, for example, the natural gas and telecommunications industries, we believe that the other three are likely to increase industry efficiency—and benefits—substantially."[16]

As our review has shown, only a much more limited set of impacts has actually been considered by recent benefit-cost studies, namely the potential for lower total production-costs through improvements from greater centralized dispatch, offset by the cost of creating and operating new institutions to manage this dispatch. By and large, entire classes of impacts, such as impacts on reliability management, generation and transmission investment and operation, and wholesale electricity market operation, have not been considered at all, at least not quantitatively. The potential benefits and costs associated with these as-yet incompletely studied impacts could easily outweigh the benefits and costs of the limited impacts that have been studied to date.

Improvements in the state of the art to expand our understanding of these impacts will not come quickly. To date, analyses have been constrained by lack of relevant data and accepted, practicable analytical tools. Nevertheless, it is important to recognize that we are 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. We urge analysts to move beyond *a priori* assumptions and simulation-based studies to rigorous analysis of the actual impacts of FERC policies. **Table 3** outlines some of the elements we recommend for inclusion in future studies.

Table 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
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

A. Reliability management

RTO formation might affect short-term reliability management in two ways:[17] First, the direct costs of managing reliability could change as result of economies (or ''dis-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 could change under an RTO. This issue has been only mentioned in recent studies. We believe this impact may be extremely significant, much more important than the dispatch efficiencies that have been estimated to date. However, quantifying this impact requires overcoming fundamental technical challenges posed by the current formulation of reliability rules, as well as a broader methodological challenge regarding what is an appropriate baseline.

The studies we reviewed considered at most two elements of the cost of managing short-term reliability. First, the direct administrative costs of managing reliability were assumed to be included in the startup and operational costs of an RTO. A few studies suggested that there could be net cost reductions as a result of centralized provision of these and other administrative functions by an RTO (compared the current situation in which these functions are provided by the individual control areas within the RTO footprint); however, none of the studies estimated these reductions. Second, the cost of procuring some reliability services, such as operating reserves, was estimated in several studies as an extension of the benefits estimated using production-cost-simulation approaches to replicate the effects of centralized dispatch over the RTO's geographic footprint.[18]

More elusive aspects of reliability management that might change under an RTO are the quality and scope of the management activities themselves. Several studies suggest that reliability management will be improved under an RTO because an RTO will have greater visibility of a larger geographic footprint and easier opportunities to re-dispatch resources over that footprint than was the case for the individual entities that make up the RTO. However, no studies have attempted to quantify this effect in terms of the impact on system reliability.

The first complication in addressing these reliability benefits and costs is that there is currently no graduated standard for assessing degrees of reliability performance other than the binary standard of compliance or non-compliance with NERC reliability rules. Moreover, it is

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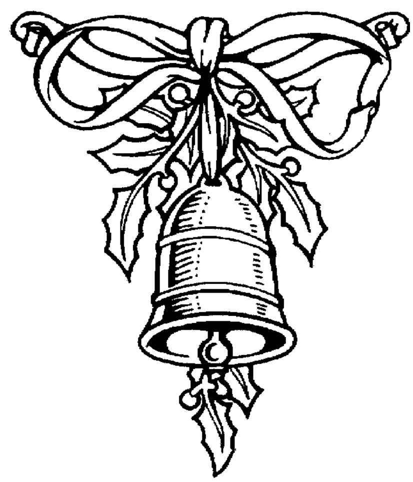
difficult to correlate a finding of ''non-compliance'' with an individual NERC rule to the relative risks that the non-compliance poses to the overall reliability of operations.

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. 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 formation of an RTO in these regions.

More RTO studies cannot, by themselves, improve on the current situation. Better quantification of reliability impacts is necessary. A first step would be development of more comprehensive reliability metrics and collection of consistent performance data over time. Recently revised NERC standards should be the starting point for this much-needed research. More importantly, the research must be undertaken for *all* organizations with short-term reliability management responsibilities, not just for current RTOs.

B. Generation and transmission operation and investment

The original studies of FERC's orders regarding electricity



industry restructuring 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; the generation fleet and transmission network are held fixed between the base and policy cases that are analyzed. As is also true for reliability management, explicit consideration of these impacts is essential for a balanced assessment of the overall impacts of FERC's policies. For example, the largest economic impact originally reported by FERC – larger than the short-run economic efficiencies that FERC reported for improved dispatch – is reduction in fixed operations and maintenance (O&M) costs, which was not assessed by any of the studies we reviewed.[19]

A handful of the studies considered quantitative operational enhancements in generator efficiency and improvements in transmission capability as part of the policy case or as a sensitivity case. The key shortcoming of these initial analyses is that the findings were driven principally by assumptions that cannot be independently verified.[20] The direction of the hypothesized changes is consistent with conventional wisdom regarding the expected impacts of increased competition, but the magnitude of the expected changes is essentially speculative.

Promising efforts are being made to improve the empirical base for assessments of the impacts of restructuring on generator performance. Markiewicz, Rose, and Wolfram apply econometric techniques to operating data collected from generating plants between 1981 and 1999 to examine changes in non-fuel expenses and employment.[21] They find larger improvements in cost efficiencies in plants operated by investor-owned utilities in restructured markets compared to costs in plants operated by investor-owned utilities in non-restructured markets (5 percent) as well as compared to those operated by municipal-federal-cooperative utilities (15–20 percent). More recently, Bushnell and Wolfram find 2-percent improvements in fuel efficiency in plants that have been divested in contrast to fuel efficiency in plants that have not been divested and that continue to operate under traditional cost-of-service rate regulation.[22]

Studies, such as the above 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 precisely determining the influence of individual FERC policies. For example, Bushnell and Wolfram observe that fuel efficiencies in non-divested plants operating under incentive rate regulations are similar to the efficiencies in plants that have been divested.[23] However, the study 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 individual 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.

Analyses of differences in technological progress, operating efficiencies, and investment between RTOs and conventional organizations are severely constrained by the available data.[24] Topics that need attention on FERC Form 1 include: (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.[25] All of these data are needed not primarily to support better RTO benefit-cost studies but to establish a robust empirical basis for ongoing assessments of the evolution of the electricity industry.

C. Wholesale electricity market operation

Despite the central role that formation of competitive wholesale markets for electricity has played in FERC's recent policies, especially in its policies on RTOs, the studies we reviewed focus only competitive-market impacts related to efficient dispatch. No other impacts of market formation and operation are addressed. Many observers believe that formal, public markets are essential for enabling and supporting risk-management strategies that directly influence the nature and pace of future investments in generation and transmission. These observers point out that RTOs are not unique in their ability to support formal wholesale markets. Importantly, these analysts note that public (as well as private) markets may be susceptible to manipulation and the exercise of market power, which may distort prices and erode the markets' credibility. Understanding the full set of impacts of wholesale electricity markets should be a critical element in an analysis of the role of FERC policies.

A handful of the studies we reviewed touch on particular aspects of the possible influences of FERC's policies on markets. As mentioned earlier, only one study directly considered the potential for abuse of market power by generators.[26] Three studies focus on the role of demand response in moderating wholesale electricity prices by introducing demand price elasticity into markets that are currently essentially price-inelastic.[27] DOE (2003) considered the role of demand response as a system

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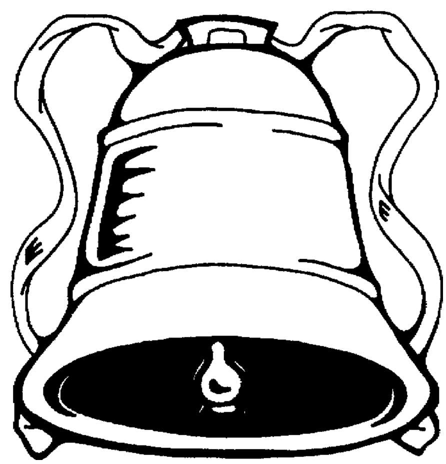
reliability resource, measuring the value of demand response by the value of (what might otherwise be) lost load.

Improving on this situation will be difficult. 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 begun addressing this issue but are focused primarily on existing RTO markets. As discussed in a recent Energy Information Administration (EIA) report, detailed, comprehensive data collection should be undertaken, starting with data on: costs of new entry, frequency of and reasons for generator access and service denial, costs and qualities of transmission service available to generators, costs of congestion, volumes and frequencies of curtailments, and flows of power (trade) across regions and the corresponding differentials in prices.[28]

V. Summary

Our review of recent benefit-cost studies of RTO formation finds many uncertainties and unexamined impacts. Because of these uncertainties and omissions, it is not currently possible 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 to some degree, we believe that future assessments should study impacts that have not been adequately examined, including impacts on 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.

Systematic consideration of these still-to-be-quantified impacts is neither straightforward nor possible without better data and thoughtful analysis. We should immediately begin collecting and analyzing these data so that future policy decisions can be based on the best possible information.■

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Endnotes:

1. FERC 2004.

2. Eto *et al.* 2005.

3. Morey *et al.* 2005.

4. More than 11 benefit-cost studies were conducted during this period; 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.

5. ICF 2002, PJM 2002, ESAI 2002, ISO-NE/NYISO 2002, and DOE 2003.

6. TCA 2002, CRA 2002, and Henwood 2004.

7. CERA 2003, SAIC 2004, and CRA 2004.

8. Production-cost simulation tools were originally developed to support generation planning by vertically integrated utilities. They minimize the cost of dispatching a fixed fleet of generation with known startup and operating costs to meet a fixed set of loads, typically for an entire year.

9. FERC 1996.

10. ISO-NE/NYISO 2002.

11. TCA 2002.

12. CAISO 2004.

13. Morey *et al.* 2005.

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.

15. FERC 1996.

16. *Id*.

17. Reliability management, for the purposes of our discussion, refers to short-term activities to ensure reliability, which involve operating 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 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.

18. TCA 2002, ISO-NE/NYISO 2002, Henwood 2004.

19. FERC 1996.

20. For example, one study assumed that transmission capability will increase by 5 percent from 2004 onward; 100 percent versus 75 percent of transmission capability will be accessible; reserve margins will decline to a system-wide average of 13 percent by 2020; fossil-fuel generation heat rates will improve by 6 percent by 2010; and unit availability will increase by 2.5 percent. One study considered sensitivity cases in which transmission capability 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). Another study assumed that coal units will be 2 percent more efficient and gas steam units will be 4 percent more efficient over five years, and that transmission capability will increase by 5 percent.

21. Markiewicz *et al.* 2004.

22. Bushnell and Wolfram 2005.

23. *Id*.

24. EIA has reached a similar conclusion. See EIA 2004.

25. FERC recently issued order 668, Accounting and Financial Reporting for Public Utilities Including RTOs, which addresses this recommendation. FERC 2005.

26. TCA 2002.

27. ICF 2002, ESAI 2002, DOE 2003.

28. We are encouraged that FERC's recent Open Access Transmission Tariff (OATT) Notice of Proposed Rulemaking will take up these issues. FERC 2006.

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