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Report to Congress:

Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design

U.S. Department of Energy

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Contents

Contents (Continued)

Page

Tables

Figures

Page

1. Introduction

Congressional Direction

This report was prepared in response to a request from Congress that the U.S. Department of Energy (DOE) conduct an independent study to assess various potential impacts of the proposed rulemaking by the Federal Energy Regulatory Commission (FERC), "Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design" (July 31, 2002).[1] In report language accompanying the Omnibus Appropriations Bill for Fiscal Year 2003, House and Senate conferees said:

> Conferees are very concerned about the possible impact on regional electricity prices of FERC's proposed rule for Standard Market Design (SMD). The Secretary of Energy is directed to submit to the House and Senate Committees on Appropriations, the House Energy and Commerce Committee, and the Senate Energy and Natural Resources Committee an independent analysis of the impact of the SMD rule that FERC proposes to finalize. This independent analysis must compare wholesale and retail electricity prices and the impact on the safety and reliability of generation and transmission facilities in the major regions of the country both under existing conditions and under the proposed new rule. This analysis must also address the proposed SMD rule's:
>
> (a) costs and benefits, including its impacts on energy infrastructure development and investor confidence;
>
> (b) impacts on State utility regulation;
>
> (c) financial impact on retail customers;
>
> (d) impact on the reasonableness of electricity prices; and
>
> (e) impact on the safe, reliable, and secure operation of the Nation's generation and transmission facilities.
>
> The Secretary shall work in consultation with the FERC so that the Secretary's analysis will most accurately address the contents and conclusions of the most current version of the proposed rule. The Secretary shall submit the independent analysis no later than April 30, 2003.[2]

In responding to this assignment, DOE has interpreted the language of the Congress as follows:

- DOE interprets the directive that its analysis is to be "independent" to mean that the Department is not to rely on the policy views of FERC staff or Commissioners in its analysis of SMD's impacts. However, DOE has not interpreted the Congressional language to bar discussions with electricity experts outside FERC. DOE believes this is consistent with the views of Chairman Domenici, as expressed at a hearing of the Senate Committee on Energy and Natural Resources on February 23, 2003.[3] Although DOE staff have conferred with a variety of electricity experts, the views expressed here represent only those of the Department of Energy.

- To address the Congressional language calling for consultation with FERC, DOE staff met with FERC staff in early March 2003 to be certain that DOE had an accurate understanding of what FERC regarded as the fundamental elements of the SMD proposal. Authorized persons at FERC indicated that the Commission's views on the essential elements of SMD were accurately summarized in an address given by FERC Chairman Pat Wood in Houston on February 13, 2003.[4] DOE's analysts met a second time with

[1]Notice of Proposed Rulemaking, 18 CFR Part 35, Docket No. RM01-212-000 (July 31, 2002) [hereafter cited as "NOPR"].

[2]Conference Report 108-10 to Accompany H.J. Res. 2 "Making Further Continuing Appropriations for the Fiscal Year 2003, and for Other Purposes" (February 13, 2003), p. 915.

[3]Chairman Domenici said: "And I want to urge that you be sure you use neutral experts, so that we get a report that is really helpful to us and does not just repeat the likes and dislikes of certain individual people but rather what is good for the country." Stenographic Transcript, p. 18.

[4]Address by FERC Chairman Pat Wood III to CERA conference, Houston, TX, February 13, 2003. See especially pp. 5-6. The speech is on FERC's web site at http://www.ferc.gov/news/speeches/commissionersstaff/CERA_Keynote_Feb_131.pdf.

FERC staff in early April 2003 to ensure that the study still reflected the Commission's evolving concepts on SMD. They were told that FERC intended to provide greater latitude to States and regions in developing regional institutions within the SMD framework. The analysis presented here reflects DOE's understanding of FERC's thinking on SMD as of early April 2003 and does not necessarily reflect views expressed in FERC's April 28, 2003, White Paper on the Wholesale Power Market Platform.

- The Congressional language directs DOE to compare various impacts under "existing conditions" and under "the proposed new rule" in the major regions of the country. In response, DOE has constructed a Non-SMD case that corresponds to "existing conditions" when the Notice of Proposed Rulemaking (NOPR) was released and assumes "business as usual" conditions in later years, and an SMD case that assumes full implementation of the proposed rule.

  Under the SMD case, all electricity generators and transmission providers would either become members of a regional transmission organization (RTO) or turn over operation of transmission operations to an independent transmission provider,[5] and all pricing (except for Federal preference power) would be based on marginal costs. To examine various aspects of the SMD case, DOE also constructed three sensitivity cases. In modeling the Non-SMD case, DOE divided the continental U.S. into 16 regions corresponding to the existing regions and subregions used by the North American Electric Reliability Council (NERC). In the SMD case and three sensitivity cases, DOE assumed formation of 8 new RTOs; however, the results of the analysis are reported using the same regional boundaries as in the Non-SMD case in order to facilitate comparisons. In discussing some impacts of SMD, the report also refers to larger geographic regions such as the Pacific Northwest and the Southeast, or the Eastern and Western Interconnections.

The remainder of this introductory chapter outlines the main features of FERC's proposal. Subsequent chapters will sketch the conceptual framework of DOE's analysis of the proposal and present the quantitative and qualitative results of the analysis.

Summary of FERC's SMD Proposal

FERC's proposal, as presented in July 2002, totaled more than 600 pages. This analysis will focus on eight key elements of SMD as discussed by FERC Chairman Pat Wood:[6]

- *An Independent Grid Operator.* "Independent" means independent of any direct or indirect links to market participants, as determined primarily by the arrangements for the governance of the RTO,[7] which FERC must approve. "Grid" refers to the facilities that the RTO would control in managing generation scheduling, dispatch, and transmission operations within its footprint. "Operator" refers to some of the RTO's key responsibilities, as explained in the paragraphs below.
- *A Long-Term Bilateral Contract Market.* In its July 2002 proposal, FERC confirmed that in its view long-term contracts are likely to be the wholesale sector's primary mode of doing business, but it did not propose specific requirements in this area. However, FERC said that it expected the proposed resource adequacy requirements (addressed separately below) to lead to substantial reliance on such contracts.
- *A Voluntary Short-Term Spot Market with Transparent Prices.* FERC's proposal would require RTOs to establish and operate day-ahead markets to coordinate generator startup ("unit commitment") decisions over a wider market area. To address energy imbalances, the proposal would require RTOs to operate real-time spot

[5]The NOPR indicates that FERC expects that "most if not all entities will become members of RTOs, and that the new Network Access Service would be provided through these RTOs. However, this rule may become effective at a time when some transmission owners and operators have not yet become members of functioning RTOs. Thus, we propose that all transmission owners and operators that have not yet joined an RTO must contract with an independent entity to operate their transmission facilities." NOPR, paragraph 8.

[6]Address by FERC Chairman Pat Wood III to CERA conference, Houston, TX, February 13, 2003, esp. pp. 5-6. The speech is on FERC's web site at http://www.ferc.gov/news/speeches/commissionersstaff/CERA_Keynote_Feb_131.pdf.

[7]FERC's proposal would establish a new type of transmission entity called an "Independent Transmission Provider" (ITP). However, an RTO would be a type of ITP, and the RTO format appears to be the one FERC prefers. For ease of presentation, this analysis will use "RTO" as a generic term that covers a range of possible options.

markets based on competitive bids; under RTO oversight, market participants are to observe transmission limits and other operating procedures needed to safeguard the grid. The proposal also requires RTOs to establish markets for certain ancillary services, and to publish promptly the prices for all regulated transactions. Participation in such markets by buyers and sellers would be voluntary.

- *Regional Transmission Planning.* An RTO would have primary responsibility for coordination of transmission planning within its footprint. However, "regional transmission planning" is a shorthand term for successful resolution of a cluster of regional planning issues, which could include guidelines for siting new generation and economically efficient use of alternatives to new transmission lines, such as distributed generation, energy efficiency, demand response programs, and improved real-time grid management.
- *Locational Price Signals.* Under SMD the regional spot markets would use "locational marginal pricing" (LMP), which takes account of transmission constraints and monetizes their consequences (see text box on page 4 for more detail on LMP). LMP induces economically efficient use of transmission capacity when it is not possible to accommodate all proposed transactions within the limits imposed by reliability requirements. LMP also helps to identify the most profitable locations for new generation capacity, and it indicates where new transmission capacity (or a functionally equivalent alternative) may be needed.
- *Tradable Transmission Rights.* Tradable transmission rights[8] are essential to SMD because they provide a means by which market participants, especially wholesale buyers, can insulate themselves against the risks of fluctuations in wholesale electricity prices under LMP due to transmission congestion.
- *Market Power Mitigation.* In FERC's view, generator bids should reflect production costs under normal conditions, as well as scarcity under peak or unusual conditions, but should not reflect market power. Accordingly, bids from generators in confirmed "load pockets"[9] would be limited to marginal production costs plus 10 percent, and bids under scarcity conditions would be capped at a proposed $1000 per megawatthour. In addition, each RTO would be required to establish a market monitoring unit that would scrutinize market operations for indications of abuses and bring any such indications promptly to the attention of FERC and of the RTO's governing body. The market monitor would also review the overall design and administration of the RTO's markets for flaws and inefficiencies.
- *Regional Resource Adequacy Requirements.* To avert capacity shortages, in its SMD proposal FERC suggested a 12 percent reserve requirement as a floor[10] and recognized that States might wish to specify higher requirements. Further, FERC proposed that "load-serving entities" (LSEs) would be required to enter contractual agreements with resource providers for resources exceeding by 12 percent or more their projected needs for the next 3 years.

[8]The terms used for such rights have not yet been standardized. FERC's NOPR uses "congestion revenue rights" (CRRs); other parties sometimes refer to "financial transmission rights" or "fixed transmission rights" or (FTRs). This report uses the terms from FERC's NOPR.

[9]A "load pocket" is a load area that has limited transmission access. Limited access makes the load pocket relatively dependent on local generation sources, and may create a potential for the exercise of market power. The problem may be compounded by an inadequacy of generating capacity within the load pocket. New York City, Boston, and southwestern Connecticut are examples of load pockets.

[10]In most States, utilities currently set reserve requirements based on a loss-of-load probability not to exceed one day in 10 years. While accepted as an industry standard, this planning requirement may not be economically justified for some consumers.

Transmission Congestion, LMP, and CRRs Explained

Functions of Transmission Grids

Today's transmission grids have three major functions:

- Their primary, everyday function is to enable the transfer of electricity in bulk from generators to population centers.
- They also enhance system reliability and reduce its cost by enabling electricity retailers to obtain bulk electricity from alternate sources under unforeseen operating conditions.
- They also reduce consumers' electricity bills by enabling retailers to obtain bulk power from the cheapest available source (i.e., electricity trade).

Consumers benefit economically from all three functions. Maintaining system reliability is economically important because outages are costly when they occur. The current benefits of electricity trade to U.S. consumers have been estimated at about $13 billion per year. Maintaining reliability while maximizing the benefits of electricity commerce requires highly coordinated and centralized management of transmission congestion.

Transmission Congestion

Congestion occurs whenever participants in a regional power market propose more transactions than the grid can safely accommodate. At present, in areas of the Nation not covered by an RTO or an independent system operator (ISO), utility employees known as security coordinators manage grid congestion by curtailing some proposed transactions when necessary; however, in many cases they lack the tools or authority to rank proposed transactions according to their economic merits. High-value transactions may be curtailed to let lower value transactions go through. Grid safety is maintained, but not in a manner that minimizes consumer costs. When grid managers must rely on curtailment to manage congestion, electricity costs tend to rise in the affected area, with adverse effects on the region's economy.

Congestion Management Under FERC's SMD Proposal

SMD proposes an RTO-administered mechanism that would preserve the reliability of the grid, put the costs of congestion management onto those whose transactions cause the congestion, and enable participants in wholesale markets to protect themselves against fluctuations in electricity prices due to changes in congestion costs. The SMD approach is based on two key concepts: locational marginal pricing (LMP) for wholesale power and a regional market in transmission congestion revenue rights (CRRs). This approach is already in use in the PJM Interconnection (which covers most of Pennsylvania, New Jersey, Maryland, and the District of Columbia), New York, the six New England States, and in varying forms in other countries. Its significant features include:

Locational Marginal Pricing (LMP). A locational marginal price is the purchase price of an incremental megawatthour in the real-time or day-ahead market at a specific time and location on the grid. The price includes generation costs based on competitive bids *and* the costs caused by transmission congestion, if any. If demand is low or moderate and the grid is not congested, LMP will be the same at all locations on the grid and will reflect the cost of the cheapest megawatt of unused generation capacity then available. However, as trade on the grid increases, the RTO will begin rescheduling transactions that would load specific lines beyond safe limits. Accordingly, some buyers seeking incremental megawatthours from the RTO's spot market will not be able to obtain access to the least-cost generator, and will have to turn to a higher cost alternative. This causes LMP to begin to vary from location to location. If the congestion becomes more widespread, the price differentials will increase.

Congestion Revenue Rights (CRRs). LMP ensures that wholesale electricity buyers face the cost of congestion management, but it also contributes to the volatility of wholesale power prices. Many market participants would resist LMP unless a way is provided to ensure access to bulk power supplies at a predictable price. CRRs are financial rights (as opposed to physical reservations of transmission capacity) that provide the holder with protection against increases in congestion costs. CRRs would be allocated initially to transmission owners or to parties who have entered contracts with such owners for the use of transmission capacity. CRRs would be specific—i.e., for a specific megawatt level, from a specific electricity entry point to electricity delivery point, and for a specified term. The holder of a CRR is entitled to any congestion revenues associated with transmission at the specified megawatt level between the specified points during the specified term, which would offset increases due to congestion costs. Payments to the holder are made through the RTO or ISO, which manages a settlement process for all transactions in the region's real-time or day-ahead markets. Assuming the holder moved the exact amount of power specified in the CRR, the CRR would reimburse the holder for congestion costs.

Trading of CRRs. After the initial allocation of CRRs, market participants could trade CRRs among themselves bilaterally. Investors in additional transmission capacity would acquire a number of CRRs commensurate with the amount of transfer capacity added. In a secondary market, the value of the CRRs would be closely linked to persistent differentials in LMP.

2. Estimating the Impacts of SMD: Analytic Framework and Methodology

In this analysis, a Non-SMD case projects a continuation of existing conditions, in which some large areas of the country have established centralized wholesale electricity markets and others have not. In the SMD case, FERC's SMD rulemaking would be finalized and all areas under FERC jurisdiction would establish fully competitive regional markets with SMD's basic features.

Types of Impacts Addressed

As discussed in Chapter 1, SMD is assumed to consist of eight major components.[1] This analysis assesses the effects of this regulatory package in terms of the six types of impact mentioned in the assignment from Congress:

- Price impacts (wholesale and retail)
- Impacts on energy infrastructure development and investor confidence
- Impacts on the reasonableness of electricity prices (e.g., price volatility and the possible need for mitigation of market power)
- Impacts on the safety and reliability of generation and transmission infrastructure
- Impacts on State utility regulation
- Regional impacts (i.e., significant variations in the distribution of the above impacts between and within regions).

Quantitative and Qualitative Approaches

We have estimated quantitatively by region the impacts of the increased electricity commerce SMD would facilitate, using two economic models. Quantitative analysis was not feasible for several impact categories, which therefore have been addressed qualitatively. Five qualitative analyses are presented in Chapter 4:

- Impacts on the reasonableness of electricity prices and potential need for market power mitigation
- Impacts on energy infrastructure development and investor confidence
- Impacts on security and reliability of generation and transmission infrastructure
- Impacts on State regulation of electric utilities
- Potential benefits of enhanced demand response.[2]

The two economic models used for the quantitative analysis were General Electric's Multi-Area Production Simulation (MAPS) model and DOE's Policy Office Electricity Modeling System (POEMS) model. GE Power System Energy Consulting and OnLocation, Inc., provided DOE with the quantitative results of the modeling runs. Charles River Associates also aided us in interpreting the outputs of the models.

MAPS is a specialized tool widely used by the electricity industry to analyze transmission issues on a regional basis. It is used to project the functioning of the generation and transmission infrastructure in great detail under different assumptions over the relatively near term (i.e., about 4 years, through 2007). Using MAPS for longer term analyses would require adding a large amount of user-specified detail about expected demand growth, new generation capacity, generation retirements, and transmission upgrades. Establishing such assumptions with the degree of detail required was not feasible within the time and budget for this study.

[1]See pages 2-3 in Chapter 1.

[2]The analysis of the potential benefits of enhanced demand response is in fact a quantitative analysis, but because the range of uncertainty in this area is very large, it is presented with the qualitative analysis in Chapter 4.

For mid-term and long-term projections, DOE found it more appropriate to use POEMS, which depicts how usage of the generation infrastructure would change over time and has full accounting of consumer electricity costs. POEMS is designed to use the demand and supply modules of the Energy Information Administration's National Energy Modeling System (NEMS). This means that the POEMS output is based on a known and tested set of assumptions and projections about future economic growth, energy demand, fuel prices, etc. POEMS projections for the electricity sector, however, are substantially more detailed than those provided by NEMS.

The MAPS model has been used here to develop transmission-related projections for 2005 and 2007. The POEMS model has been used for electricity sector projections from 2005 through 2020. The assumptions used for the Non-SMD case and for the SMD case were the same in the two models. The results from the two models were consistent, although different in focus.

Non-SMD Case, SMD Case, and Sensitivity Cases

Background Assumptions Common to All Cases

The assumptions listed below were common to all cases:

- Fuel price projections were taken from the *Annual Energy Outlook 2003.*[3] Prices for natural gas delivered to electricity generators are projected to average $3.40 per million Btu in 2005, increasing to $4.40 per million Btu by 2020 (in 2002 dollars). Coal prices are projected to decline slightly in real terms.
- Electricity demand was taken from the *Annual Energy Outlook 2003.* The average increase is about 1.8 percent per year from 2005 to 2020.
- Planning reserve margins were set to 15 percent for all regions except New York (18 percent) and Florida (which is assumed to meet a 20 percent reserve requirement by relying in part on capacity in neighboring southeastern States). These assumptions are based on current State law or practice.
- Environmental laws and regulations were assumed to continue as currently written.
- Sales to end users were priced by POEMS region, either by cost of service or marginal cost, depending on whether the State has adopted retail competition.
- No expansion of existing load management or demand response programs was assumed.

Non-SMD Case

This case corresponds roughly to the status quo as of 2002. Four RTOs, excluding the Electric Reliability Council of Texas (ERCOT), are assumed to exist: ISO New England, New York ISO, PJM (Pennsylvania, New Jersey, Maryland, Delaware, and the District of Columbia), and California ISO. In the Non-SMD case, PJM does not include Allegheny Power or the proposed new additions to PJM (transmission facilities from Dominion Resources, American Electric Power, Dayton Power & Light, and Commonwealth Edison). Each RTO has "license plate" transmission pricing,[4] market-based energy pricing, and minimal market inefficiencies. However, there are still obstacles to electricity commerce ("seams") and transmission fees between RTOs. The non-RTO regions are reported according to the boundaries of North American Electric Reliability Council (NERC) subregions, with pancaked transmission fees (see box on page 7) between power control or market areas and market inefficiencies within and between these areas.

Expansion of the transmission grid over time is not explicitly assumed, except for upgrades and replacements necessary to connect new generators and maintain reliability. From a modeling perspective, this means that transmission capability is held constant. Some regions have cost-of-service regulation at the retail level, and some are based on marginal cost pricing for the generation component of retail electricity prices. This difference reflects which States have adopted competition in retail electric markets. Some States, especially those in transition to competition in retail markets, have imposed freezes on retail rates for varying periods. Taking such freezes into account in the modeling was not feasible within the time and budget constraints for this analysis.

[3]Energy Information Administration, *Annual Energy Outlook 2003*, DOE/EIA-0383(2003) (January 2003).
[4]See text box on page 7 for details concerning "license plate" transmission pricing and related terms.

SMD Case and Sensitivity Cases

The SMD case represents a future in which all components of the proposed SMD are implemented successfully. Most of the Nation is divided into 12 regions. (Certain limited areas—Alaska, Hawaii, and Texas/ERCOT—are excluded from the analysis, because in electrical terms they are not interconnected with the Nation's other systems, and SMD does not pertain to them.) Each RTO has license plate transmission pricing, LMP, and minimal internal market inefficiencies. Obstacles to commerce are also reduced between RTOs, although transmission fees still apply between them. The status of retail competition is unchanged from the Non-SMD case, and reserve margins are also unchanged.

For the SMD case, we increased the operational transmission capability by 5 percent within the areas of the new RTOs to reflect the concept that, when transmission is managed in larger regions, operators are able to increase some flows safely because they are managing both sides of a transmission interface. Arguably, SMD would facilitate a significant quantity of new transmission investment. To assess the impact of this view, we tested in a sensitivity case the impact of a 10 percent increase in transmission capability resulting from postulated new transmission investment. This sensitivity case assumes that only cost-effective investments are made, but no attempt is made to quantify the cost of specific expansions. We recognize that only in some situations are the benefits from reducing congestion sufficiently large to pay for transmission upgrades, particularly if wholly new lines are required.

Generator efficiency for fossil steam plants is assumed to be 2 to 4 percent higher in new RTO regions in the SMD case. Based on empirical evidence of generator efficiency improvements in the past few years for plants in the Northeast ISOs relative to the rest of the Eastern Interconnection, coal plants are assumed to improve by 2 percent and gas steam plants by 4 percent.[5] The rationale is that better price signals will provide to generators (in regions with retail competition) and regulators (in regulated regions) the incentive or information that leads to better plant performance.[6]

Alternative Approaches to Transmission Pricing

FERC's NOPR discusses three approaches to recovering the costs of building, maintaining, and operating a region's transmission infrastructure through transmission rates:

- "Pancaked" pricing, in which the transmission charge for a transaction reflects an accumulation of charges levied by individual utility control areas along a contract path between the point where the electricity is put into the grid and the point of delivery. This pricing method is commonly used in regions that do not have RTOs.
- "License plate" pricing, in which a single fee is charged for a transaction within an RTO. The actual fee varies somewhat within the RTO and is based on the zone to which the electricity is delivered.
- "Postage stamp" pricing, in which a single and uniform fee is applied across an entire RTO.

In theory, the three approaches should yield similar results, because they are alternative ways of recovering the same amount of money. However, pancaked pricing is administratively cumbersome and non-transparent, and as a result it substantially inhibits regional electricity commerce. License plate pricing is used in RTOs currently, and it would be used in new RTOs under SMD. In the SMD NOPR, the Commission proposed to shift eventually to postage stamp pricing within RTOs.

To illustrate the effects of the various assumptions, three sensitivity cases were created:

(1) *SMD case with expanded transmission:* Same as the SMD case, but assumes 10 percent increase in transmission capability

[5]Details on the empirical support for assumed generator efficiency improvements are provided in Appendix B for this report. See U.S. Department of Energy, *Appendices to Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design* (May 2003).

[6]There are anecdotal indications that regional competition and LMP induce higher generator availability and efficiency. An examination of Continuous Emission Monitoring System (CEMS) data has confirmed heat rate improvements. An examination of Generator Availability Data System (GADS) data for a comparable improvement in availability was inconclusive.

(2) *SMD case with no increase in transmission capability:* Same as the SMD case, but assumes 0 percent increase in transmission capability

(3) *SMD case with no generator efficiency improvements:* Same as the SMD case, but assumes no improvements in generator efficiency in new RTO areas.

Table 2.1 summarizes the assumptions in the Non-SMD case, the SMD case, and the three sensitivity cases.

Table 2.1. Description of Non-SMD and SMD Cases

Assumption	Non-SMD Case	SMD Case	Sensitivity Cases
RTOs	Four RTOs as of 2002: ISONE, NYISO, PJM,[a] CAISO	Four existing RTOs plus eight new RTOs: GridSouth, SETrans, GridFlorida, TVA, MISO (including SPP),[b] Translink-West, RTO West, and WestConnect	
Barriers to Wholesale Electricity Commerce	Combined hurdle rates[c] and transmission fees pancaked in non-RTO regions No cost for transmission within existing RTOs	No cost for transmission within RTOs Reduced cost between RTOs	
Transmission Expansion	None	5% increase in capability in 2005, from improved operational efficiency at seams that existed in Non-SMD case	(1) SMD case with 10% increase in all limiting transmission interfaces (2) SMD case with 0% increase in transmission capability
Generator Efficiency	Higher efficiencies in RTO areas (ISOs) than in non-RTO areas	Generator efficiency improvements in new RTO areas	(3) SMD case with no generator efficiency improvements in new RTO areas

[a]Does not include Allegheny Power or the proposed new additions to PJM (transmission facilities from Dominion Resources, American Electric Power, Dayton Power & Light, and Commonwealth Edison).

[b]SPP announced its decision not to join MISO after this analysis was begun.

[c]Barriers to commerce are modeled as “hurdle rates” or minimum benefits that a proposed electricity transaction must provide in order to go forward.

Limitations of Cost/Benefit Analysis of Standard Market Design

There are at least three types of limitations:

Effects of "planner's paradox." Regulators and policymakers fashion policy proposals to address particular problems. Both their characterization of the problems and their expectations about the effectiveness of the proposed solutions are unavoidably affected by a network of assumptions and by information limitations. The "planner's paradox" is the difficulty of being adequately prepared for "unknown unknowns"; preventive measures can be designed to address known risks and problems. Changing major features of the regulatory landscape inevitably triggers unanticipated cause-and-effect sequences—some good and some bad, some large and some small. The cost/benefit analyst is affected by planner's paradox in much the same way as the policymaker—for both, the challenge is to characterize as accurately as possible both the direct, intended consequences of a policy measure and its indirect and perhaps unintended consequences.

Nearsightedness. A corollary limitation is that in such analyses it is much easier to assess accurately the near-term impacts than the long-term impacts. Yet for most major regulatory proposals the long-term impacts are likely to be more important. In the SMD context, for example, a near-term effect of shifting to region-wide economic dispatch of generation under RTOs and LMP is more efficient use of the existing generation fleet and transmission system. As described below, these gains can be estimated through an economic model. Over the long term, however, SMD would provide participants in electricity markets large amounts of critical market information that is not available to them today. This information will enable the market participants to make more timely business decisions with lower risk, particularly concerning new investments. For reasons explained below, it is not possible to estimate many of these benefits quantitatively with confidence. Four examples of such improvements in market information, and their possible consequences, are discussed in Chapter 4.

Conservatism of Long-term Equilibrium Models. An equilibrium model for energy markets, such as the one used for this analysis (POEMS[a]) begins with a set of assumptions about variables such as future economic growth, electricity demand, fuel prices, generation capacity by type and location, etc. The model estimates a least-cost solution to meeting electricity demand and presents results in terms of patterns of electricity generation and market-clearing prices. From these results, the analyst can estimate whether certain policy changes are likely to induce lower overall costs for consumers or achieve other desired policy objectives. However, the model relentlessly equilibrates away many key differences or uncertainties over time: for example, new generation is always sited in the most economic location, using the most appropriate technology; fuel price changes follow a smooth path or vary within a specified range. Thus, the model tends to underestimate electricity commerce (as well as other energy trade) over the long term, because it lacks the unforeseen, destabilizing inputs that are normal in a real economy and that provide the economic stimulus for a significant portion of total trade volume.

Given the limitations on the foresight of both the regulatory policymaker and the cost/benefit analyst, DOE believes that it would be important in the present case for FERC to establish mechanisms for periodic assessments of whether a final SMD rule was having its intended effects.

[a]See page 11 in Chapter 3 for more detail on POEMS. DOE recognizes that not all cost/benefit studies involve the use of long-term equilibrium models.

3. Estimating the Impacts of SMD: Quantitative Analysis of Increased Electricity Commerce

This chapter presents the results of DOE's quantitative analysis of SMD impacts, using two economic models, POEMS and MAPS. POEMS was used to project the impacts of increased electricity trade on wholesale and retail electricity prices. MAPS was used to project near-term changes in the use of transmission networks. As described above, the two models were set up with essentially identical supply, demand, and fuel price assumptions, and they produced generally consistent results. In addition, DOE estimated the costs of implementing SMD. The projected impacts on retail electricity prices include both the effects of increased electricity trade and the estimated SMD implementation costs. For the reasons stated in Chapter 2, DOE believes that quantitative projections such as those shown below are likely to underestimate the price impacts of SMD (i.e., net economic benefits), particularly for the long term.

Wholesale and Retail Price Impacts of Increased Electricity Commerce Under SMD

The POEMS Model

The Policy Office Electricity Modeling System (POEMS) is an integrated energy model of the United States with a specific focus on the electric sector. The POEMS model incorporates a detailed integrated multi-market model that uses a constrained bilateral transaction framework for electricity market analysis employing transmission fees, transmission constraints, hurdle rates, and alternative definitions of bidding behavior. The POEMS multi-energy sector implementation relies on the Energy Information Administration's National Energy Modeling System (NEMS) and its *Annual Energy Outlook 2003* assumptions[1] and results for the non-electricity sectors. NEMS represents all the supply and demand sectors of the U.S. energy system.

In POEMS, TRADELEC replaces the Electricity Market Module of NEMS to add detail and enable disaggregation of results. TRADELEC was designed specifically for analyzing competitive electricity markets and the transition from regulated markets. POEMS develops an economic capacity expansion plan to meet future demand requirements (representing a step-wise optimal expansion plan). The expansion plan incorporates the current environmental regulations of the Clean Air Act and other relevant regulations. The expansion planning explicitly addresses the retirement of uneconomical and unused generating capacity.

POEMS has been used to perform analytic studies of many energy sector issues. It was used to support DOE's analysis of the Comprehensive Electricity Competition Act proposed by the Clinton Administration. For various participants in electricity markets, POEMS has been used to assess regional markets, forecasting electricity prices, supply, and demand under alternative economic and fuel price scenarios. The model has also been used to assess the impact of alternative environmental policies on utility industry capital turnover and inter-fuel substitution.[2] It was also used in the National Transmission Grid Study to examine the value of trade and the economic propensity for inter-regional transmission congestion.[3]

DOE believes that POEMS produces a conservative estimate of the trade-related benefits of SMD because:

[1]For a detailed description of NEMS, see Energy Information Administration, *Assumptions for the Annual Energy Outlook 2003 With Projections to 2025*, DOE/EIA-0554(2003) (January 2003).

[2]For a more complete description of POEMS, see U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (May 1999); and Appendix A for this report in U.S. Department of Energy, *Appendices to Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design* (May 2003).

[3]U.S. Department of Energy, *National Transmission Grid Study* (May 2002).

- POEMS utilizes all resources in a market area to meet native demand efficiently in that same area; i.e., POEMS does not discriminate against local nonutility generating capacity in establishing its merit order dispatch.[4]
- POEMS, like most models used for long-term projections, assumes that economic agents act in an economically rational manner over time; i.e., investors in new generation and other electricity-related assets are assumed to deploy them in optimal quantities and locations. In practice, many factors can lead to less than optimal capacity expansion.

POEMS Scenario Assumptions

The assumptions used in POEMS were the same as those used in the GE-MAPS™ model to the extent practical, given the differences in the modeling frameworks.

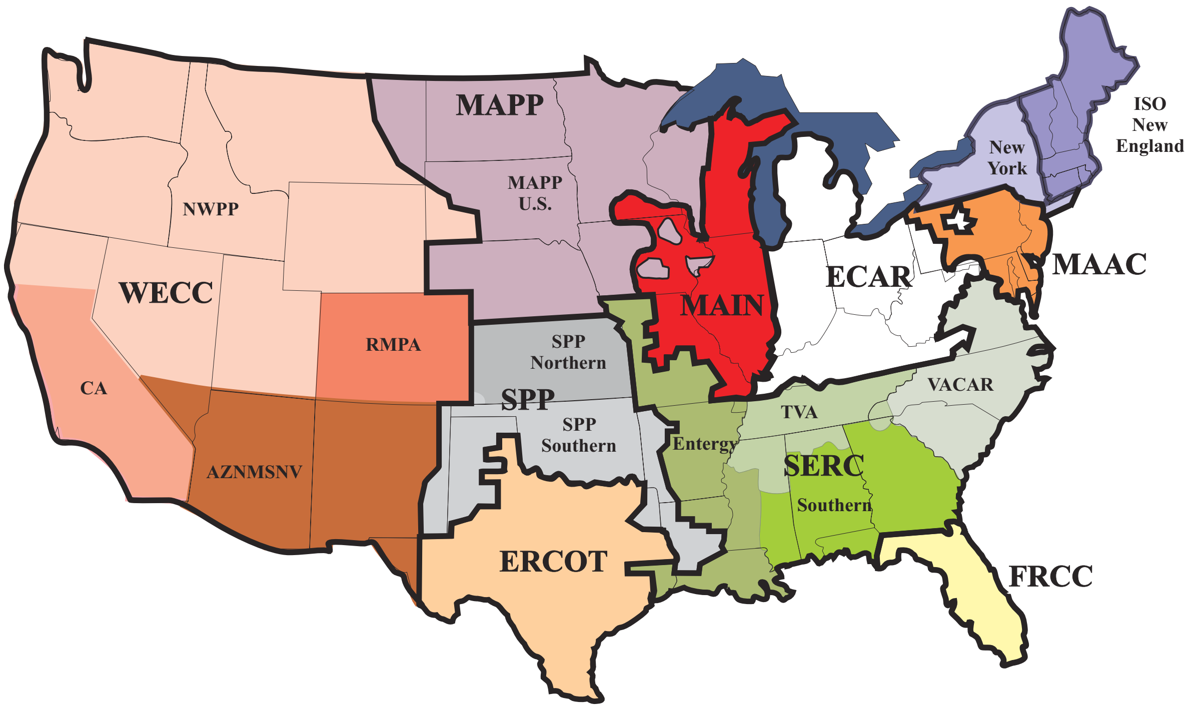
- In the Non-SMD case, transmission fees were assumed to be pancaked in all market areas that do not currently have RTOs.
- The transmission constraints, fees, and hurdle rates for wholesale electricity transactions were set to correspond to the same level of market inefficiency represented in the MAPS modeling.
- In the SMD cases and the sensitivity cases, all regions were assumed to have RTOs, and pancaking was eliminated.
- The costs to establish 8 new RTOs and operate all 12 of them under SMD amount to about $760 million per year (in 2002 dollars). The basis for this figure and the allocation of the costs on a regional basis is explained below.
- The generator efficiency improvements of 2 percent for coal steam and 4 percent for gas steam plants were phased in over a 5-year period, assuming that not all plant owners would achieve the improvements immediately. The least efficient plants were assumed to be improved the most, and those that are already very efficient would not be improved.
- Reserve margins were set at 15 percent for all areas except New York (18 percent) and Florida (20 percent, 5 percent of which may come from out-of-State sources). The reserve requirements do not change between cases, and the SMD case does not attempt to measure the capital cost savings that may be associated with greater opportunities for reserve sharing under SMD.
- The model was initialized with existing capacity, augmented with all currently known and planned generating capacity under construction and expected to be on line by 2004 (consistent with the input to the MAPS modeling). This results in significant overcapacity in most regions initially. Subsequent retirement of significant oil and gas steam generating capacity is assumed to occur, followed by additional new construction as economically justified.
- The impacts on retail rates were estimated at the generation and transmission functional level. The costs of distribution functions were unchanged across all cases.
- The status of competitive retail choice varies by region and was assumed to remain unchanged in all cases.
- No additional demand response was assumed in the SMD case. (Chapter 4 includes a separate analysis of the potential impacts of enhanced demand response under SMD.) Historical demand programs are imbedded in the underlying load data and so are incorporated in the projections.
- Demand levels were held constant between cases, so that consumer benefits could be measured without the complexity of shifting demand due to price changes.

The regional results for all cases are presented at the NERC subregion level (Figure 3.1), because these are familiar boundaries in the electrical system.[5] The analysis covers the U.S. portion of the

[4]DOE does not know to what extent such discrimination exists under current operating practices, but there is reason to assume that it exists and that its adverse impacts on consumers is not trivial (see NOPR, paragraphs 57-60, and Supplemental Comments of TECO Energy, Inc., in Dockets RM01-12-000, RM02-1-000, and RM02-12-000 of February 4, 2003). Due to limitations of time, budget, and pertinent data, we were not able to estimate the potential benefits of eliminating such discrimination.

[5]The names that correspond to the acronyms for the NERC subregions are as follows: AZNMSNV = Arizona, New Mexico, and Southern Nevada; CA = California; ECAR = East Central Area Reliability Coordination Agreement; ENTERGY = Entergy; ERCOT = Electric Reliability Council of Texas; FRCC = Florida Reliability Coordinating Council; MAAC = Mid-Atlantic Area Council; MAIN = Mid-America Interconnected Network; MAPP = Mid-Continent Area Power Pool; NE = ISO New England; NY = New York; NWPP = Northwest Power Pool; RMPA = Rocky Mountain Power Area; SOUTHERN = Southern Company; SPP = Southwest Power Pool; TVA = Tennessee Valley Authority; VACAR = Virginia and Carolina.

Figure 3.1. Major Regions of the United States for DOE's SMD Analysis, Based on NERC Subregions



NERC regions only. In the SMD case, 12 RTOs are formed in the lower 48 States, excluding ERCOT. Table 3.1 shows the relationship between the subregions and the RTOs.

Costs To Implement SMD, Including Establishment and Operation of RTOs

The costs of implementing SMD are subject to considerable uncertainty. This is partly due to the uncertainty about the final rule itself and partly to uncertainty about how to separate the impact of the SMD rule from the costs already incurred in response to previous FERC orders, especially FERC's Order No. 2000, which has resulted in substantial effort to establish RTOs. Moreover, it is difficult to estimate how much operational savings may be achieved as the RTO dispatch function under SMD begins to substitute for the utility dispatch function that exists today. These factors have been addressed in this study, but not perfectly.

Table 3.2 shows a median estimate of the total annual revenue requirement of the various RTOs expected to evolve in the United States, excluding Texas, Alaska, and Hawaii. The table reports estimated costs for 2005, converted to 2002 dollars to be consistent with costs used elsewhere. The bases for the cost estimates are different for different RTOs and are noted in the table. Some of the estimates have been taken from the annual reports of ongoing ISOs[6] and RTOs; some are based on

Table 3.1. NERC Subregions and RTOs

NERC Subregion	SMD RTO(s)
NE	ISO New England
NY	NY ISO
MAAC	PJM
VACAR	PJM, GridSouth
Southern	SeTrans
FRCC	GridFlorida, SeTrans
ECAR	PJM, MISO
TVA	TVA
MAIN	MISO, PJM
Entergy	SeTrans
MAPP	MISO
SPP	MISO
NWPP	RTO West
RMPA	Translink West
AZN	WestConnect, RTO West
CA	CAISO

[6]New York, New England, and California have Independent System Operators (ISOs) as opposed to RTOs. For the purposes of this analysis, it is assumed that the ISOs will become RTOs under SMD.

cost estimates developed specifically for the RTO; and the remainder are based on estimated average costs extrapolated back to the load in the region. These cost estimates are also affected by assumptions about how many RTOs would be established. This study assumes a total of 12 RTOs, not including ERCOT. DOE assumes that the total number of RTOs is unlikely to go higher, but if the number of RTOs were reduced, the total costs probably would be somewhat lower.

The total annual revenue requirement is an estimate of the total costs of running the RTO, assuming that SMD has been implemented in 2005. This includes amortized startup and ongoing operational costs. For the purposes of this study, RTO startup capital is assumed to be amortized over a 10-year period. The total annual cost includes the base cost of existing ISOs and an expected amount of incremental costs that would be incurred by existing ISOs in implementing SMD. In the case of

Table 3.2. Summary of Annual RTO/SMD Costs, 2005 (2002 Dollars)

Region	A RTO Annual Revenue Requirement (Million Dollars)	B Annual Generation (Terawatthours)	C RTO/SMD Costs (Dollars per Megawatthour)	Incremental SMD Costs After 10% Savings	
				D Million Dollars	E Dollars per Megawatthour
1. ISO New England	63	130	0.48	—	0.00
2. NY ISO	135	163	0.83	—	0.00
3. PJM	287	702	0.41	86	0.12
4. MISO	155	784	0.20	140	0.18
5. SPP	33	80	0.41	29	0.37
6. RTO West	116	284	0.41	105	0.37
7. WestConnect RTO	34	82	0.41	30	0.37
8. California ISO	234	278	0.84	12	0.04
9. Rocky Mountain	22	54	0.41	20	0.37
10. SeTrans	117	463	0.25	105	0.23
11. GridSouth	109	219	0.50	98	0.45
12. GridFlorida	109	208	0.52	98	0.47
13. TVA	45	177	0.25	40	0.23
Total	**1,457**	**3,623**	**0.40**	**762**	**0.21**
Other Benchmarks					
14. Ontario IMO	85.3	154	0.55		
15. ERCOT	121.9	292	0.42		

General Assumptions: Costs grow by 2% per year; load grows by 1% per year.
Sources:
- Incremental costs (D) based on CRA assumptions.
- All costs assumed to be in 2005 dollars and deflated to 2002 dollars using factor of 0.922.
- ISO New England (1A) data from ISO New England Inc. Annual Report for Year Ended December 31, 2002; (1B) from NERC ES&D for 2002.
- NY ISO (2A) data from NY ISO presentation "Projects Budget Review" (March 28, 2003); (2B) from NERC ES&D for 2002.
- PJM (3A and 3B) from New PJM Companies' FERC Filing.
- MISO (4A) from MISO 2003 Budget Summary - No SPP Merger; (4B) from FERC Form 1 (401a) for companies in MISO.
- SPP annual energy (5B) from FERC Form 1 (401a) for companies in SPP; (5C) assumed to equal (4C) and (5A) calculated from (5B) and (5C).
- RTO West (6A) taken from "RTO West Benefit/Cost Study" conducted by Tabors Caramanis & Associates (March 11, 2002), lower bound of estimate; (6B) from FERC Form 1 (401a) for companies in RTO West.
- WestConnect annual energy (7B) from FERC Form 1 (401a) for companies in WestConnect; (7C) assumed to equal (6C) and (7A) calculated from (7B) and (7C).
- California ISO (8A and 8B) from "RTO West Benefit/Cost Study," Table 23.
- Rocky Mountain ISO annual energy (9B) from FERC Form 1 (401a) for companies in WestConnect; (9C) assumed to equal (6C) and (9A) calculated from (9B) and (9C).
- SeTrans (10A and 10B), GridSouth (11A and 11B) and Grid Florida (12A and 12B) based on SEARUC Report.
- TVA incremental cost (13C) set equal to that estimated for SETrans; (13B) from NERC ES&D for 2005.
- Ontario IMO (14A and 14B) from "IMO 2002-2004 Business Plan" (October 2001). Canadian dollar costs converted to US dollars using conversion factor of 1.5796 C$/US$.
- ERCOT (15A and 15B) from "RTO West Benefit/Cost Study," Table 23.

RTOs that do not currently exist, the total annual cost represents an estimate of establishing the RTO and implementing SMD. Table 3.2 reports this total as about $1.46 billion per year. This total annual revenue requirement includes amounts that are not attributable to FERC's proposed SMD rule itself and is reported here for comparison purposes only.

Column D of Table 3.2 reports the estimated incremental cost of the FERC SMD rule. For the purposes of this study, it is assumed that adoption of the proposed rule would result in certain savings that are difficult to quantify, incorporated here as a 10 percent savings of the estimated cost. The basis for this 10 percent savings is an expectation that SMD will result in certain economies, such as the transfer of knowledge and experience from existing RTOs and ISOs to the new RTOs being formed around the country; the potential consolidation of control areas from the current level of about 150 down to a smaller number over time; the possible avoidance of capital cost and software expenditures that otherwise might have been needed to upgrade existing utility control center operations; improved regional planning; and consistency in market design.

For ISO-NE and NYISO, the study assumes a net incremental cost of zero to implement SMD, on the grounds that SMD efficiencies should roughly balance any needed expansion of RTO functions. For PJM, the incremental cost reflects the addition of the new PJM member companies (AEP, ComEd, DP&L, Dominion, and APS), reduced by the above expected savings. For the California ISO, a 5 percent net incremental cost has been assumed, based on the known need to upgrade from a zonal to an LMP system. For MISO and the remaining RTOs, the incremental cost is considered to be the full cost of the RTO reduced by the 10 percent savings discussed above.[7]

Table 3.2 shows that a median estimate of the cost of FERC's SMD rule is about $760 million per year nationally. This is about $0.21 per megawatthour (MWh). This incremental cost cannot be estimated precisely. It is possible that the costs could be lower or higher, depending on how the rule is implemented and the extent to which existing technology can be transferred to the new RTOs. The range of uncertainty is estimated to be about $100 million, meaning that the incremental cost of implementing the SMD rule might be as low as $660 million or as high as $860 million.

As shown in Figures 3.2 and 3.3, the estimated costs have been redistributed in the POEMS outputs to conform to the NERC regional boundaries. The total cost of about $760 million dollars annually is allocated to customers at an average cost of $0.22 per MWh at retail. Regions with existing RTOs have zero additional costs. The largest total costs are expected in ECAR, FRCC, VACAR, and NWPP (Figure 3.2). On a cost per MWh basis, the costs are highest in FRCC, VACAR, NWPP, and RA (Figure 3.3).

Figure 3.2. Total RTO Costs by NERC Subregion

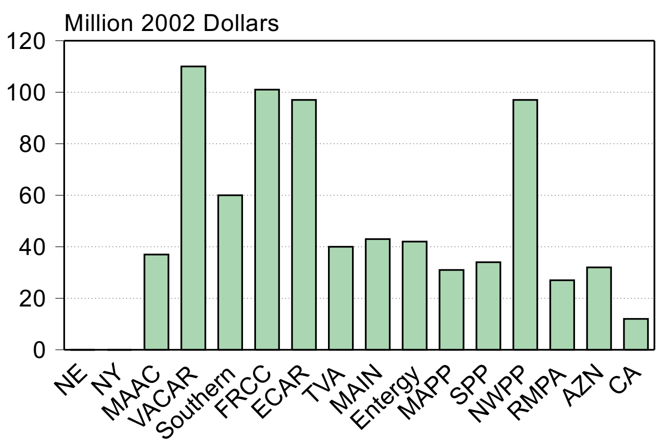
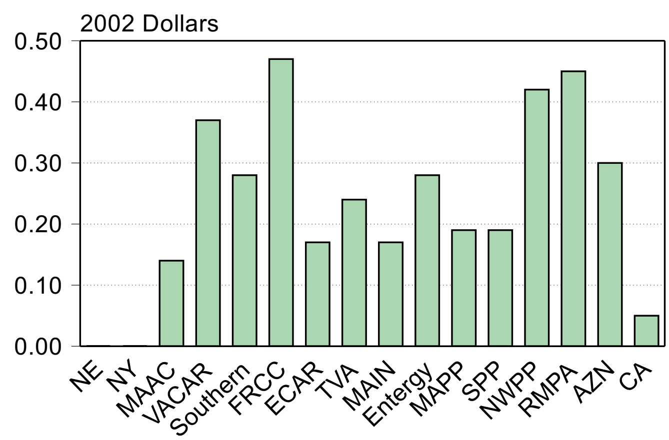


Figure 3.3. RTO Costs per Megawatthour by NERC Subregion



[7]This treatment of MISO costs is intended to be consistent with the benefit modeling done for this study, in which the pre-SMD case reflects an absence of RTOs/ISOs outside the Northeast and California. In this view, MISO and the other formative RTOs represent incremental benefits of the SMD rule, and a consistent treatment of the costs requires that the full costs of MISO and the other new RTOs be included as well.

Non-SMD Case Results

The projections begin with the current surplus of capacity that exists in many markets of the country. As depicted in Figure 3.4, we project the existence of almost 100 gigawatts of capacity (excluding ERCOT) above what is needed to meet peak demands including reserves in 2005. The new capacity is expected to be primarily gas-fired combined cycle units and combustion turbines. The greatest amounts of surplus are projected to be in the ECAR, MAAC, New England, Entergy, and Southern regions. These are the regions where the most new power plant construction has occurred in the past several years. The additional capacity is likely to displace old oil and gas steam generation capacity that is less efficient, and it will be used over time to meet new demand growth.

Over time the surplus is projected to diminish through retirements of uneconomic units and demand growth projected at 1.8 percent per year. By 2008 many regions are expected to need new capacity, and by 2020 almost 250 gigawatts of new capacity construction is projected. Two-thirds of the new capacity consists of natural-gas-fired combined-cycle units or combustion turbines, and one-third is coal-fired. The new plants are assumed to be located so as to reduce system costs and meet reserve requirements. No assumption was made to reflect any current locational inefficiencies associated with the placement of new capacity.[8]

As described previously, the Non-SMD case represents current transmission arrangements, in which transmission fees are pancaked in large areas of the Nation and where individual companies must seek out bilateral trading partners without a formal market structure. Even with these market inefficiencies, a substantial volume of trading occurs. A proportionally larger fraction of intra-regional trade occurs in the West, in part because of the sale of hydroelectric power from Federal dams to a large number of utilities.

Over time POEMS projects the overall volume of wholesale commerce as roughly constant, which means that it is shrinking somewhat as a percent of total generation requirements. Demand growth that reduces the capacity surplus in many regions, and the construction of new capacity in regions where it is needed, gradually reduce the reliance on trade. However, the projections indicate that in most regions significant trading opportunities will remain. Seasonal differences in demand across regions, the availability of electricity from low-cost sources, and the opportunity to build new power plants where the fuel sources are cheapest lead to continued reliance on commerce. For example, it is unlikely that new coal-fired power plants would be built in California, and so California will continue to import both coal-fired and hydroelectric generation from other areas in the West.

The projected near-term trading pattern is shown in Figure 3.5. Regions such as ECAR, MAAC, Southern, AZN, and NWPP are large exporters of low-cost power, while New York, Florida, VACAR, and California are primarily importers.

Figure 3.4. Supply/Demand Balance, 2005

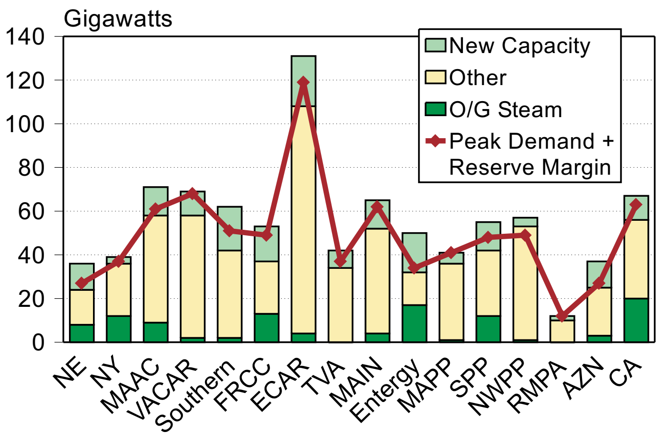
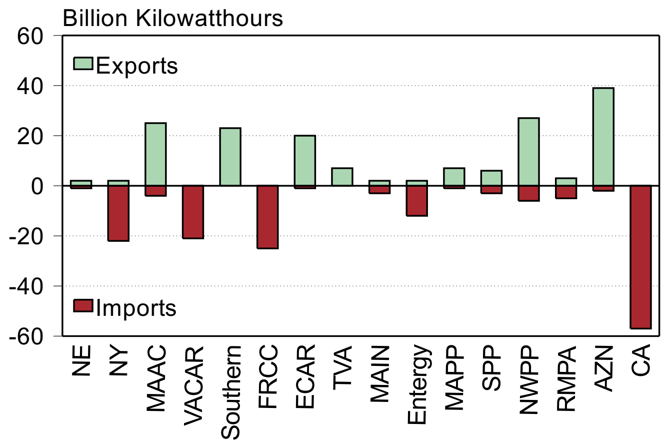


Figure 3.5. Near-Term Inter-Regional Commerce in the Non-SMD Case



[8]Because of the level of aggregation in POEMS, the placement of plants to relieve transmission congestion in specific areas is not considered.

Projections of near-term wholesale prices in the Non-SMD case are shown in Figure 3.6. Importing regions generally experience higher wholesale prices due to their more expensive mix of generation relative to exporting regions. Although imports help to reduce prices, obstacles to commerce mean that not all possible economic trades are found. In some areas, transmission congestion may also prevent the transfer of power from one region to another.

Figure 3.7 shows projections of near-term generation and transmission components of retail electricity prices in the Non-SMD case. Consumer costs must reflect generation and transmission costs and are assumed to be based either on cost-of-service regulated rates or on competitive market prices, depending on whether the region has adopted competitive retail choice. The State-specific complexities of transition issues such as stranded cost recovery and rate freezes could not be considered in this national study.

Figure 3.6. Near-Term Wholesale Market Prices in the Non-SMD Case

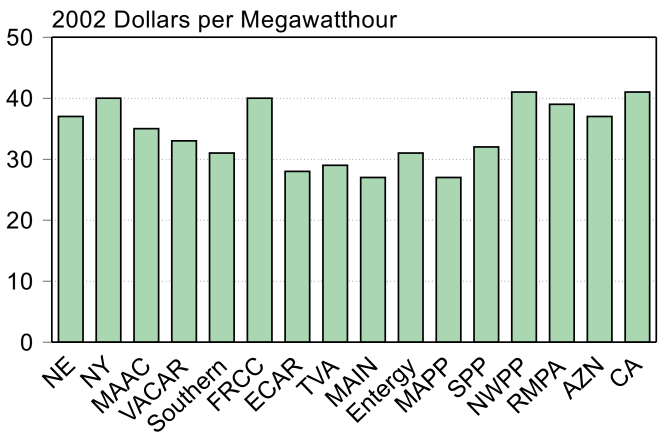
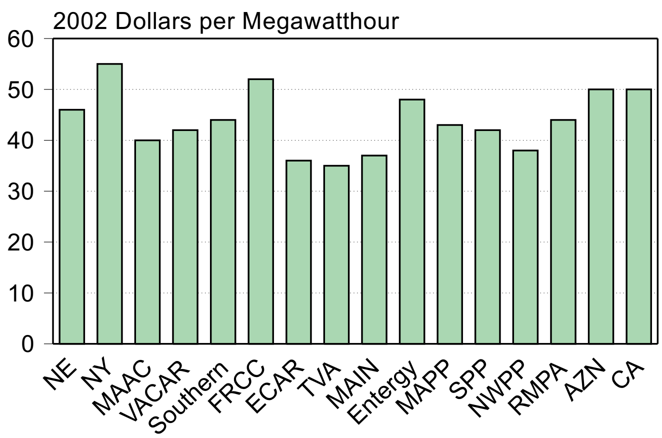


Figure 3.7. Near-Term Generation and Transmission Components of Consumer Prices



The cost-of-service prices are built-up rates from embedded capital costs and annual fuel and operating costs. For regions that have adopted competitive retail choice, market-driven wholesale prices directly determine consumer costs, adjusted for the consumer's load shape and losses incurred in delivery of electricity to the consumer. Retail customers may not literally face fluctuating time-of-day wholesale prices, but their rates must reflect the trends and conditions in wholesale markets (see box on page 18 for additional details).

Wholesale trading yields benefits to both seller and buyer that are valued here either on a traditional split-savings basis or on the basis of the market price. The split-savings approach is used if both parties are utilities that are not in existing RTOs, as there is not an established market price. If one of the utilities is in an RTO, then the market-clearing price of the importer is used. If the seller is a nonutility, it would presumably not sell using split savings, but instead the buyer would pay the equivalent of a competitive market price. In all areas, revenue from the collection of wholesale transmission fees is used to offset the transmission component of prices to native retail customers.

SMD Case Results

As shown in Table 3.3, average wholesale prices under SMD are estimated to decrease by about 1 percent in 2005 and by about 2 percent by 2020 relative to the non-SMD case. As shown in Table 3.4, the generation and transmission component of retail prices would decrease by an average of about 1 percent. The tables also indicate significant regional variance in these wholesale and retail price changes. *All the estimates presented in this analysis are subject to significant uncertainty, because they are dependent on assumptions about future conditions in the economy and the electricity sector.*

Projected changes in wholesale electricity prices as a result of increased wholesale commerce under SMD are shown in Table 3.3. Operation of the most expensive units that were setting market-clearing prices in the Non-SMD case has been displaced by operation of lower cost units. The largest reductions in wholesale prices are in MAAC, FRCC, SPP, CAL, and NWPP. In some exporting regions, wholesale prices rise because of competing demands for their low-cost power. In the near term (2005-2010), these regions include ECAR, MAIN, MAPP, and TVA (Figure 3.8 and

Electricity Pricing

Wholesale electricity prices, in the terms used here, are the prices received by generators and paid by load-serving entities (utilities that serve retail customers) in short-term transactions—as opposed to the prices in long-term bilateral contracts. Annual values for wholesale prices can be calculated either by averaging each hourly price equally (time-weighted) or by taking into account the changes in volume sold at different prices (quantity-weighted). The latter is used here, because it better reflects the value of the power consumed.

Wholesale prices can be set through ***competitive*** markets or ***split-savings*** agreements. ***Competitively determined prices*** are based on the marginal cost of the last power plant needed in a given hour to satisfy demand. The plant could be located within the demand area or some distance away, in which case the cost would include the transmission charges to deliver the electricity to the demand area. If there were no transmission fees, losses, or congestion, wholesale prices would be the same everywhere. In reality, of course, all these exist, and prices will generally be lower where low-cost generators are located. The change in wholesale prices between the SMD and Non-SMD cases shown in Table 3.3 are for competitive wholesale prices calculated on a load-weighted basis.

Split-savings pricing is a traditional method, historically used in power pools and other economy energy agreements, for establishing prices for short-term transactions between utilities. The savings associated with a given transaction is the difference between what it would cost the buyer to produce the electricity itself and the price for the same quantity from a cheaper source. Under split-savings pricing, the savings achieved by the transaction are shared evenly between the buyer and seller. In the Non-SMD case it is assumed that transactions between utilities are priced on the basis of split-savings if the two are in areas without RTOs or formal markets (i.e., outside of New England, New York, PJM, or California). All purchases between utilities in which at least one belongs to an RTO are priced competitively, with the assumption that trading will occur at these transparent prices. In addition, all purchases from nonutilities are priced at the competitive wholesale price. In the SMD case, once all regions have RTOs and real-time markets, the competitive prices are used, with the exception of Federal power, which is priced on a split-savings basis.

The reported wholesale prices in the SMD case include the costs of SMD implementation (i.e., the incremental costs of establishing and operating RTOs in compliance with SMD requirements). These costs vary by RTO.

Retail prices paid by consumers consist of generation, transmission, and distribution components. Because the distribution portion is assumed to be unaffected by the SMD proposal, the effects on retail prices reported here are restricted to the generation and transmission components. Depending on whether an area has adopted retail choice, the generation component is based either on ***cost-of-service*** regulation (in regulated regions) or ***market-clearing prices*** (in competitive regions). Cost-of-service prices are built up from embedded capital costs and annual fuel and operating costs. Purchased power costs and profits from exports both flow through rates to the customer. In the SMD case, the generation component of the retail price paid by the consumer is affected by fuel cost savings associated with greater trade, shifts from split-savings to competitive wholesale prices (where applicable), changes in competitive wholesale prices (where applicable), and changes in import and export volumes.

For regions that have adopted competitive retail choice, market-driven wholesale prices directly determine consumer costs, adjusted for the consumer's load shape and losses incurred in delivery of electricity to the consumer. (Generally, the regions with retail choice are also the ones that have RTOs and real-time markets.) Retail customers may not literally face fluctuating time-of-day wholesale prices, but their rates must reflect the trends and conditions in wholesale markets.

In the SMD case, consumer prices include the SMD implementation costs previously shown in the wholesale prices.

The transmission component of retail prices is assumed to remain cost-of-service based in all regions. As part of their electric bills, retail customers typically pay small charges to cover the costs to build, maintain, and operate their area's portion of the transmission system, minus any revenues collected by the transmission owner from wholesale trades. In the Non-SMD case, with traditional transmission fees the retail customer's portion of transmission costs is reduced when wholesale transactions associated with selling across or out of the area pick up some of the costs. With the simpler and reduced transmission fees in the SMD case, transmission revenues from wholesale transactions in general are reduced. The basic costs for the transmission system, however, remain fixed; this means that any region that had a substantial transmission revenue credit from the wholesale market in the Non-SMD case will, in the SMD case, probably have to pass a somewhat larger fraction of the transmission system's costs on to retail customers.

Table 3.3). In the long term (2016-2020), the same general pattern of wholesale price changes is projected, but the price increases in the exporting regions are generally smaller (Figure 3.9 and Table 3.4).

The effects of SMD on retail rates are influenced to a significant extent by whether the States in question have cost-of-service regulation or competitive retail choice. In some regions, most of the States have cost-of-service regulation (cost-based rates). Other regions have few if any cost-of-service States, and retail prices are determined by market forces.

With cost-based rates, utility costs for fuel and purchased power are passed through to consumers. In a shift to SMD, both the volumes of and

Figure 3.8. Near-Term Wholesale Market Prices in the Non-SMD and SMD Cases

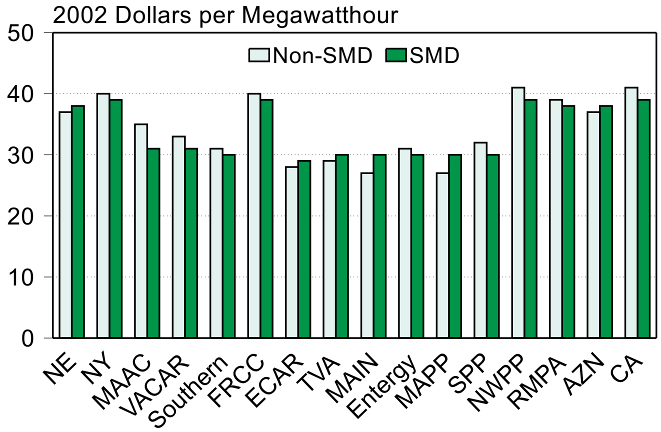


Figure 3.9. Long-Term Wholesale Market Prices in the Non-SMD and SMD Cases

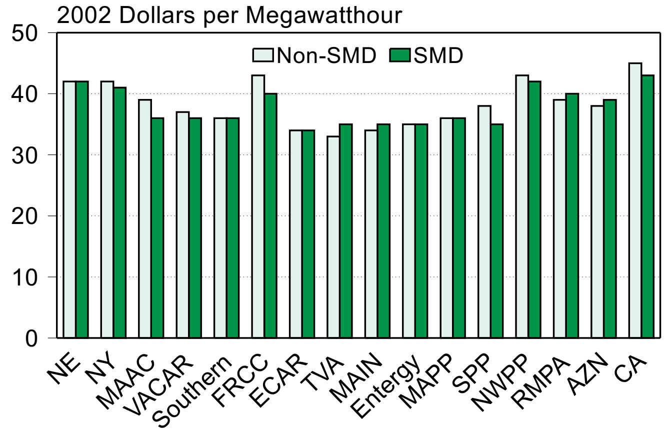


Table 3.3. Projected Percentage Changes in Wholesale Electricity Prices Under SMD by Region, 2005-2020

Region	Projected Change in Wholesale Prices from Non-SMD to SMD (Percent)		
	Near Term	Mid-Term	Long Term
NE	1	-1	-1
NY	-2	-2	-1
MAAC	-11	-7	-6
VACAR . . .	-4	-4	-3
Southern . .	-3	-3	-1
FRCC	-4	-6	-7
ECAR	4	3	1
TVA	4	2	7
MAIN	10	7	4
Entergy . . .	-2	-3	-1
MAPP	10	0	-1
SPP	-4	-8	-7
NWPP	-4	-3	-3
RMPA	-2	2	2
AZN	1	1	3
CA	-4	-4	-4
Average . .	**-1**	**-2**	**-2**

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.
Source: POEMS Model scenario outputs.

Table 3.4. Projected Percentage Changes in Generation and Transmission Components of Retail Electricity Prices Under SMD, 2005-2020

Region	Projected Change in Retail Price Generation and Transmission Components from Non-SMD to SMD (Percent)		
	Near Term	Mid-Term	Long Term
NE	0	-1	0
NY	-1	-1	0
MAAC	-7	-4	-4
VACAR . . .	-2	-1	-1
Southern . .	1	0	1
FRCC	1	1	1
ECAR	-1	-2	-2
TVA	0	0	0
MAIN	4	3	3
Entergy . . .	0	0	0
MAPP	-3	-2	-1
SPP	-1	-1	-1
NWPP	1	1	1
RMPA	1	-1	0
AZN	3	3	3
CA	-2	-1	-1
Average . .	**-1**	**-1**	**-1**

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.
Source: POEMS Model scenario outputs.

prices for imports and exports would change. Retail prices would be affected either by the shift induced by SMD from "split-savings" to market prices for wholesale transactions or by the changes in the volumes and prices for imports and exports, or by both of these. (See text box on page 18 for additional detail.) For some importing regions with cost-based rates, the net result could be increased costs associated with wholesale purchases, which would be passed through to retail customers. For example, a 1 percent increase is projected for FRCC (Florida). For some exporting regions with cost-based rates, additional utility revenues from exports could lead to lower retail prices for the region. In MAPP, for example, retail prices are projected to be 1 percent to 3 percent lower.

In regions in which most States have adopted retail choice, changes in wholesale prices would have a more direct effect on consumer prices. For MAIN and AZN, SMD could lead in some years to increased electricity exports, which lead to higher market-clearing prices in the short-term markets and somewhat higher consumer prices. Conversely, MAAC and California are projected to see increased imports, lower wholesale prices, and lower prices for consumers. The magnitude of the projected changes in the generation and transmission components of retail prices (positive or negative) generally decreases over the study period.

The net benefit for all consumers is about $1 billion per year over the first 6 years (the near term), after factoring in the estimated $760 million per year in RTO costs. Although the annual net consumer benefits decline slowly over time, they are still about $700 million per year for the long term (2016-2020), as shown in Figure 3.10.

The regional impacts of SMD on consumer prices (with the SMD implementation costs included) are shown below for the mid-term and long-term period (Figures 3.11 and 3.12). As with the wholesale prices, the retail price effects are moderated over the long term. These benefits accrue from increased commerce in the SMD case. Interregional commerce increases particularly in the East, where pancaked transmission fees are eliminated (Figure 3.13).

In the Eastern Interconnection, the greatest differences are increased coal-based production in ECAR, MAIN, and MAPP, displacing more expensive coal-based generation in MAAC and oil- or gas-fired generation in several regions (Figure 3.14). Although MAAC and ECAR are reported here by the same NERC subregion boundaries as in the Non-SMD case, portions of ECAR and MAIN

Figure 3.10. Total Consumer Benefits and RTO Costs in the SMD Case

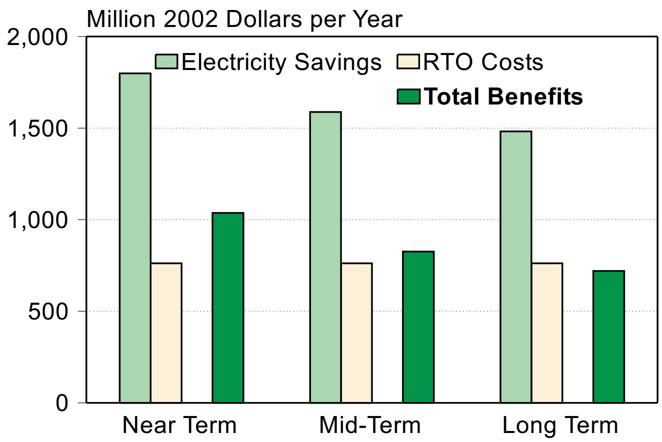


Figure 3.11. Near-Term Changes in Consumer Prices in the SMD Case (Annual Averages, 2005-2010)

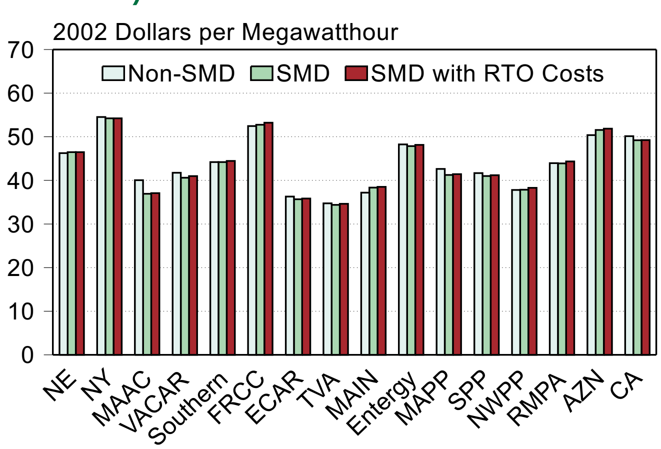


Figure 3.12. Long-Term Changes in Consumer Prices in the SMD Case (Annual Averages, 2016-2020)

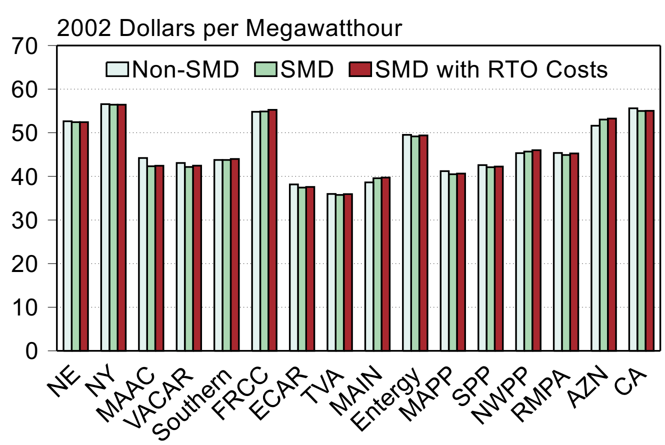


Figure 3.13. Volume of Inter-Regional Commerce in the Non-SMD and SMD Cases

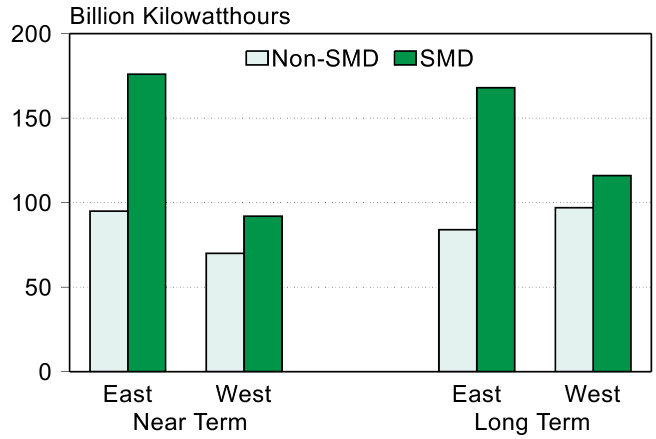


Figure 3.14. Near-Term Regional Shifts in Generation in the SMD Case

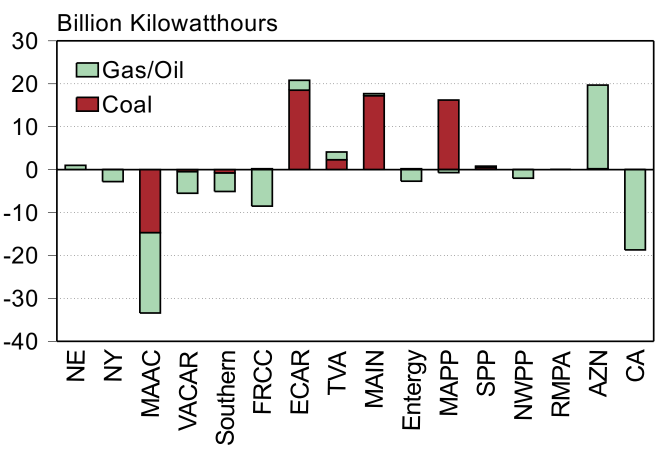
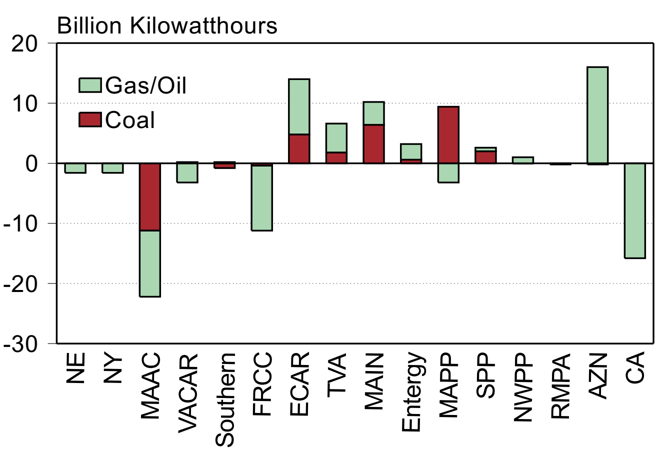


Figure 3.15. Long-Term Regional Shifts in Generation in the SMD Case

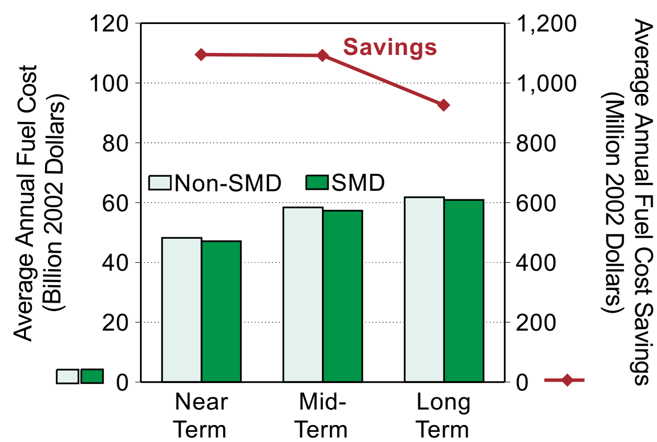


become part of the PJM RTO in the SMD case. This allows significantly reduced hurdles to trading among these areas. In the Western Interconnection, there is a shift toward greater use of combined-cycle units in Arizona, which displaces use of oil/gas steam plants to serve California.

These fuel shifts continue in the later years (Figure 3.15), although the displacement of gas-fired generation with coal-fired generation diminishes as new capacity is constructed. In the long term, the generation shifts in both interconnections include a significant amount of gas-to-gas displacement. Usage of nuclear and renewable generation plants does not change between cases, because they have low operating costs and are always fully used when available.

Greater trade means more displacement of high-cost generation with lower cost generation, resulting directly in lower total fuel costs (Figure 3.16). In the near-term period of SMD implementation, fuel savings are projected to be almost $1.1 billion per year, compared with a total fuel bill of $48 billion. In the long term, savings fall to about $0.9 billion per year. The reduction declines over time because the fuel savings from displacement of high-cost gas-fired generation by lower cost gas-fired generation is smaller than if coal is the displacing fuel.

Figure 3.16. Fuel Cost Savings in the SMD Case



Sensitivity Case Results

Three sensitivity cases were constructed to gauge the effects of some of the assumptions made about the impacts of SMD. The sensitivity cases changed the assumptions as follows:

(1) *SMD case with expanded transmission **(SMD w/ 10%T)**:* Same as the SMD case, but assumes 10 percent increase in transmission capability

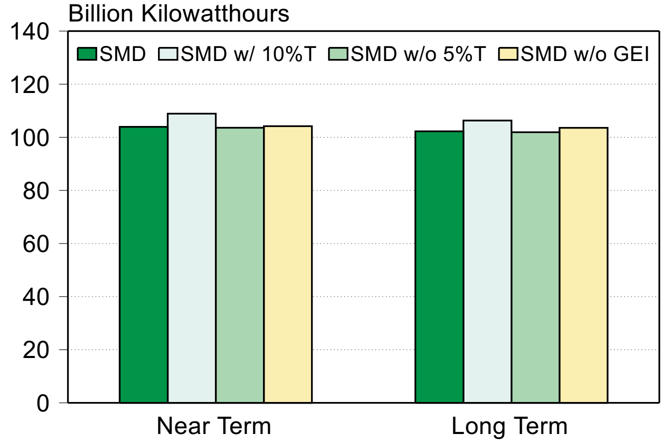
(2) *SMD case with no increase in transmission capability **(SMD w/o 5%T)**:* Same as the SMD case, but assumes 0 percent increase in transmission capability

(3) *SMD case with no generator efficiency improvements **(SMD w/o GEI)**:* Same as the SMD case, but assumes no improvements in generator efficiency in new RTO areas.

Table 2.1 in Chapter 2 summarizes the assumptions in the Non-SMD case, the SMD case, and the three sensitivity cases.

The total volume of commerce projected by POEMS is not much affected in the sensitivity cases (Figure 3.17). The 5 percent increase in transmission capability associated with the formation of new RTOs has a negligible impact on the projected amount of commerce. The generator efficiency improvement assumption has a small impact on commerce volumes. The 10 percent increase in transmission capability at limiting interfaces, including across RTO boundaries, has a small impact nationally (about 5 billion kilowatthours). Most of the increase in inter-regional flow is between MAAC and New York, Southern and Florida, and AZN and California. These are areas in which congestion occurs with enough frequency for the 10 percent increase to make a significant difference.

Figure 3.17. Inter-Regional Commerce in the SMD and Sensitivity Cases



The change in fuel cost savings is more visible between the cases, with the exception of the 5 percent change in transmission capability, where very little change occurs. The generator efficiency sensitivity case illustrates that widespread improvements in plant efficiency can yield significant cost savings, but that even without them the fuel savings expected from SMD are $800 million to $500 million per year. In the first 6-year period, this contribution is smaller because of the assumption that not all plants would be improved immediately. The full effect is not seen until 2010. The savings are smaller in the later years, because the amount of trading declines. The expansion of transmission capability saves an additional $30 million to $50 million per year relative to the SMD case (Figure 3.18 and Table 3.5).

Figure 3.18. Average Annual Fuel Cost Savings in the SMD and Sensitivity Cases

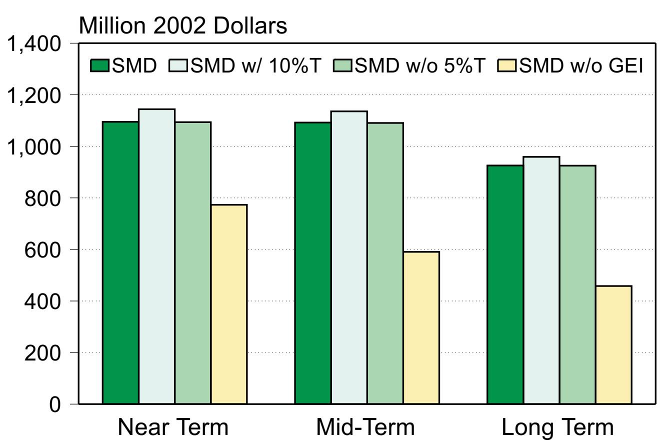


Table 3.5. Average Annual Fuel Cost Savings in the SMD and Sensitivity Cases

Analysis Case	Fuel Cost Savings (Billion 2002 Dollars) Near Term	Mid-Term	Long Term
SMD	1.1	1.1	0.9
SMD w/ 10% T	1.1	1.1	1.0
SMD w/o 5% T	1.1	1.1	0.9
SMD w/o GEI	0.8	0.6	0.5

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.
Source: POEMS Model scenario outputs.

The net total consumer cost savings (taking into account the SMD implementation costs) relative to the Non-SMD case is similar in the transmission capability sensitivity cases (Figure 3.19 and Table 3.6). Little change is induced by omitting the assumed 5 percent intra-RTO improvement. With the 10 percent expansion in transmission capability, the additional consumer benefit is $20 million to $80 million per year. If no generator efficiency improvements are assumed, the savings are still $900 million per year in the near term. The benefit after the SMD implementation costs have been deducted drops to about $200 million to $250 million per year in the later years.

The following pages present brief summaries of the projected SMD impacts in the 16 NERC subregions.

Figure 3.19. Average Annual Consumer Cost Savings in the SMD and Sensitivity Cases

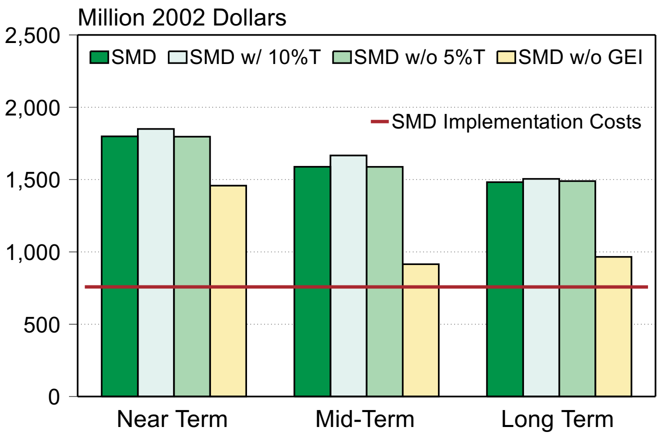


Table 3.6. Average Annual Consumer Cost Savings in the SMD and Sensitivity Cases

Analysis Case	Consumer Benefits (Billion 2002 Dollars) Near Term	Mid-Term	Long Term
Consumer Electricity Savings			
SMD.	1.8	1.6	1.5
SMD w/ 10% T.	1.8	1.7	1.5
SMD w/o 5% T.	1.8	1.6	1.5
SMD w/o GEI.	1.5	0.9	1.0
SMD Implementation Costs			
All Cases	0.8	0.8	0.8
Net Consumer Benefit			
SMD.	1.0	0.8	0.7
SMD w/ 10% T.	1.1	0.9	0.7
SMD w/o 5% T.	1.0	0.8	0.7
SMD w/o GEI.	0.7	0.2	0.2

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.
Source: POEMS Model scenario outputs.

Discussion of Regional Impacts

New England Region (NE)

Applicable RTOs: ISO-NE

Retail Rate Regulation: All competitive except Vermont

New England is a net exporter to New York in the near term in both the Non-SMD and SMD cases. In the long term New England becomes a small net importer. There is slightly more wholesale commerce in the SMD case due to the assumption that the hurdle rate between RTOs is reduced by SMD effective in 2005. In practice, it may take longer for such “seams” issues to be resolved.

Most of the region has adopted competitive retail choice, and the market sets both wholesale and retail prices. Initially wholesale prices are slightly higher for New England in the SMD case, because prices are being bid up by selling more to New York; in later years prices are slightly lower than in the Non-SMD case. At the retail level, the generation and transmission component increases in price in the near term by just under 0.5 percent; in the mid- and long term it declines by around 0.5 percent.

Table 3.7. New England Region: Model Results

Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	1	2	3	1	3	4	1	1	1
Exports	2	1	1	4	1	1	2	1	0
Generation	142	150	156	143	150	155	1	-1	-1
Coal	21	21	27	21	21	27	0	0	0
Natural Gas	70	76	75	71	76	74	1	0	-1
Other	51	53	54	52	53	54	0	-1	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0	0	0	—	—	—
Wholesale Prices	37	42	42	38	41	42	1%	-1%	-1%
Retail G&T Prices	46	51	53	46	51	52	0%	-1%	0%
	Billion Dollars								
Consumer G&T Costs	5.9	7.1	7.6	6.0	7.0	7.6	0%	-1%	0%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

New York Region (NY)

Applicable RTOs: NYISO

Retail Rate Regulation: Competitive

New York is a net importer in both cases, but the amount imported diminishes over time. With the reduced fees and hurdle rates in the SMD case, New York can import economically from more distant regions, such as ECAR. This allows for the displacement of more expensive gas-fired generation, particularly in the early years.

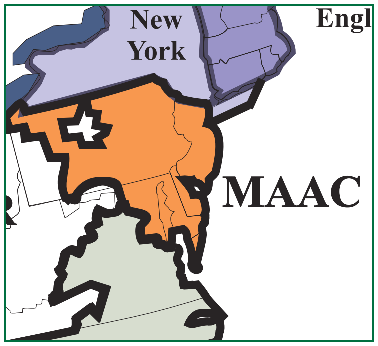
Wholesale market-clearing prices are slightly lower in the SMD case as a result of the increased imports. New York is a competitive retail region; thus, although retail customers may not pay the actual fluctuating time-of-day wholesale prices, their rates will reflect underlying conditions in wholesale markets.

Table 3.8. New York Region: Model Results

Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	22	18	17	26	23	21	4	4	4
Exports	2	2	3	3	5	5	1	2	3
Generation	157	175	181	154	173	180	-3	-2	-1
Coal	30	33	45	30	33	45	0	0	0
Natural Gas	57	71	66	55	69	65	-3	-2	-1
Other	70	71	69	69	70	70	-1	0	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0	0	0	—	—	—
Wholesale Prices	40	42	42	39	42	41	-2%	-2%	-1%
Retail G&T Prices	55	58	57	54	57	56	-1%	-1%	0%
	Billion Dollars								
Consumer G&T Costs	8.9	10.1	10.1	8.9	10.0	10.1	-1%	-1%	0%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.
Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.
Source: POEMS Model scenario outputs.

MAAC Region (most of Pennsylvania, New Jersey, most of Maryland, Delaware, and the District of Columbia)



Applicable RTOs: PJM

Retail Rate Regulation: All competitive

MAAC is a net exporter in the Non-SMD case, primarily to New York. In the SMD case PJM has expanded, and commerce with the Midwest becomes cheaper (due to no transmission fees within the PJM RTO and no pancaking). As a result, MAAC becomes a net importer, with most of the new imports coming from ECAR. The additional imports displace generation from the more expensive coal and gas plants in the fleet.

Wholesale prices are much lower due to greater commerce, and the SMD implementation costs are modest. The region has adopted retail choice, and the market sets consumer and wholesale prices. Even if customers bought on a term-contract basis, those contracted prices would reflect underlying competitive conditions in wholesale markets. In the Non-SMD case, customers are projected to see an increase of $0.2 to $0.3/MWh in the transmission component of prices, because incremental wholesale transmission revenue is credited back to customers. In the SMD case, with fewer transmission fees collected on a transaction basis, less is available to net back to customers.

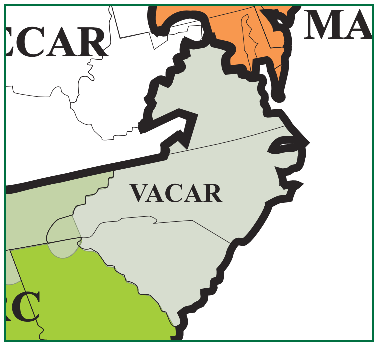
Table 3.9. MAAC Region: Model Results

Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	4	5	4	31	25	28	27	21	24
Exports	25	24	21	19	25	23	-6	1	2
Generation	317	342	357	284	322	335	-33	-20	-23
Coal	149	153	166	134	144	155	-15	-9	-11
Natural Gas	48	61	60	30	50	50	-18	-11	-11
Other	120	128	131	120	128	130	-1	0	-1
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.1	0.1	0.1	—	—	—
Wholesale Prices	35	39	39	31	36	36	-11%	-7%	-6%
Retail G&T Prices	40	45	44	37	43	42	-7%	-4%	-4%
	Billion Dollars								
Consumer G&T Costs	11.0	13.3	14.0	10.2	12.8	13.5	-7%	-4%	-4%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.
Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.
Source: POEMS Model scenario outputs.

Discussion of Regional Impacts

VACAR Region (eastern Virginia, North Carolina, and South Carolina)



Applicable RTOs: PJM and GridSouth

Retail Rate Regulation: 70 percent cost of service; 30 percent competitive

The VACAR region is primarily an importer of electricity in both cases. The reduction in pancaked fees in the SMD case leads to higher imports, displacing more expensive generation. This displacement, in concert with the lower transmission fees, reduces wholesale prices in the region.

Consumer prices fall for both cost-of-service and competitive areas, but especially for the competitive area due to lower wholesale prices. For the cost-of-service regions, the assumption that utilities move from split-savings prices to competitive wholesale rates in the SMD case does not have much impact in the region. The SMD implementation costs create some upward pressure on prices but do not outweigh the other effects that reduce prices.

Table 3.10. VACAR Region: Model Results

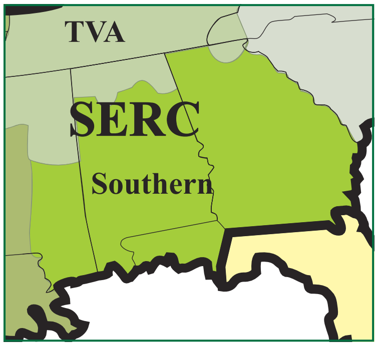
Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	21	26	18	29	32	23	8	6	6
Exports	0	0	0	2	2	4	2	2	3
Generation	319	360	408	314	355	406	-6	-5	-2
Coal	167	185	228	167	184	228	-1	-1	0
Natural Gas	21	41	44	17	38	42	-4	-4	-2
Other	131	134	136	130	134	136	-1	0	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.4	0.3	0.3	—	—	—
Wholesale Prices	33	38	37	31	36	36	-4%	-4%	-3%
Retail G&T Prices	42	42	43	41	42	42	-2%	-1%	-1%
	Billion Dollars								
Consumer G&T Costs	13.3	15.3	17.2	13.0	15.1	17.0	-2%	-1%	-1%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

Southern Region (Georgia, most of Alabama, and parts of Florida and Mississippi)



Applicable RTOs: SETrans

Retail Rate Regulation: All cost of service

The Southern region is a net exporter in both cases in all years, primarily exporting to Florida. In both cases the interface with Florida is used to its limit a significant portion of the time, although to a greater extent in the SMD case.

The SMD implementation costs are projected to be moderate in the Southern region. Wholesale prices decrease slightly due to lower exports in the near and mid-term. As a result, retail generation and transmission prices increase very slightly in the SMD case relative to the Non-SMD case (close to 0.5 percent in all periods). The generation component of the price is reduced slightly by increased revenues from utility exports. Although the volume of exports is diminished or only slightly higher, the average price is higher. In the Non-SMD case, utilities are assumed to buy and sell power with other utilities using a split-savings approach, where buyer and seller share equally the benefits of the transaction. In the SMD case, the assumption is that all transactions will take place at the wholesale market-clearing price. As a result, the average price received by the Southern region is higher in the SMD case.

In the SMD case, wholesale transmission revenues are significantly reduced with the elimination of pancaked fees and with lower fees between the RTOs, resulting in a slight increase in the transmission component of retail rates. Finally, the costs of SMD implementation, while small, add roughly 0.5 percent to the generation and transmission component of rates.

Table 3.11. Southern Region: Model Results

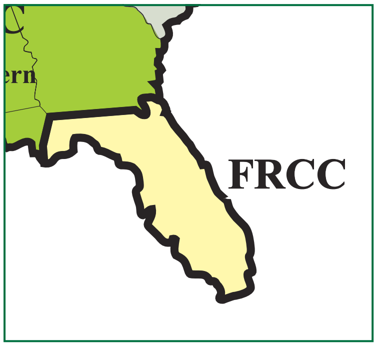
Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	0	1	1	4	4	3	3	3	2
Exports	23	18	16	22	18	18	-2	1	2
Generation	263	286	310	258	284	309	-5	-2	0
Coal	180	191	214	179	190	213	-1	-1	-1
Natural Gas	27	39	38	22	38	39	-4	-1	0
Other	56	57	58	56	57	58	0	0	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.3	0.2	0.2	—	—	—
Wholesale Prices	31	37	36	30	36	36	-3%	-3%	-1%
Retail G&T Prices	44	43	44	44	44	44	1%	0%	1%
	Billion Dollars								
Consumer G&T Costs	9.9	11.0	12.2	10.0	11.0	12.2	1%	0%	1%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

FRCC Region (most of Florida)



Applicable RTOs: GridFlorida, SETrans

Retail Rate Regulation: All cost of service

Florida is an importer in all years in both cases. Its primary trading partner is the Southern region. With market inefficiencies eliminated in the SMD case, Florida trades with more distant regions as well. The transmission interface between Florida and the Southern region is congested a significant portion of the time and becomes more so in the SMD case.

The SMD implementation costs are estimated to be among the highest in the country. Even so, wholesale prices are lower in all years in the SMD case, as more operation of Florida's expensive oil- and gas-fired plants is displaced through commerce.

Retail rates, on the other hand, are projected to be slightly (1 percent) higher in the SMD case. In the Non-SMD case, utilities are assumed to price transactions with other utilities at split-savings (each shares half the benefit of the trade). Only purchases from nonutilities are at market prices. Once there are transparent wholesale markets in the SMD case, all wholesale purchases are made at the market price. For Florida, this leads to a net increase in costs for purchased power. To the extent that Florida utilities are already obtaining the equivalent of competitive market rates or may be able to continue prior long-term contracts, the 1 percent rate increase might be reduced or not occur.

Table 3.12. FRCC Region: Model Results

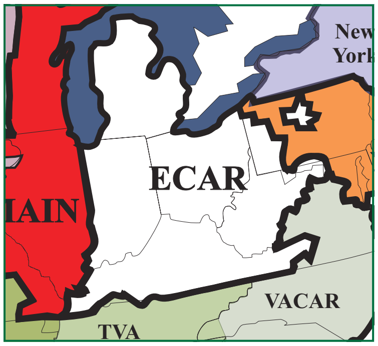
Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	25	18	17	34	33	29	9	15	12
Exports	0	0	0	0	0	0	0	0	0
Generation	217	256	286	208	242	275	-8	-14	-11
Coal	77	108	152	77	108	152	0	0	0
Natural Gas	87	96	83	85	89	79	-2	-7	-4
Other	53	53	51	46	46	44	-7	-7	-6
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.5	0.4	0.4	—	—	—
Wholesale Prices	40	44	43	39	41	40	-4%	-6%	-7%
Retail G&T Prices	52	55	55	53	56	55	1%	1%	1%
	Billion Dollars								
Consumer G&T Costs	11.9	14.1	15.6	12.0	14.3	15.8	1%	1%	1%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

ECAR Region (lower Michigan, western Pennsylvania, West Virginia, Ohio, Indiana, and Kentucky)



Applicable RTOs: PJM and MISO

Retail Rate Regulation: 70 percent cost of service; 30 percent competitive

ECAR has a large amount of low-cost generating capacity and is an exporter in both cases. With the reduction of market inefficiencies through SMD, the region is able to export larger quantities and for a greater distance. Initially, existing coal-fired capacity is the major source of exports, but over time ECAR also exports generation from new low-cost gas-fired combined-cycle plants.

Wholesale prices are projected to rise due to increased demand in the SMD case. Consumer prices fall slightly, primarily as a result of the additional revenue earned from export sales by the cost-of-service areas. The SMD implementation costs are expected to be minimal, because part of the region is joining the existing PJM RTO and the other portion is joining MISO, which is projected to have relatively low implementation costs.

Table 3.13. ECAR Region: Model Results

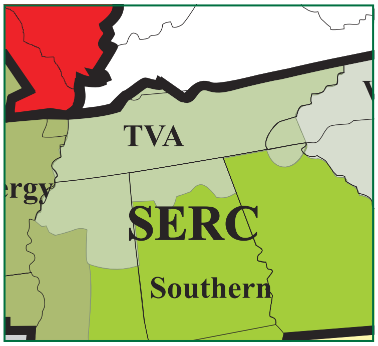
Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	1	1	3	7	8	11	6	7	9
Exports	20	23	16	45	50	38	25	27	22
Generation	645	709	747	665	730	761	21	21	14
Coal	542	574	587	560	586	592	19	12	5
Natural Gas	42	75	99	44	84	108	2	9	9
Other	61	60	61	61	60	61	0	0	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.2	0.2	0.1	—	—	—
Wholesale Prices	28	33	34	29	34	34	4%	3%	1%
Retail G&T Prices	36	38	38	36	38	38	-1%	-2%	-2%
	Billion Dollars								
Consumer G&T Costs	21.2	24.6	26.2	21.0	24.3	25.8	-1%	-2%	-2%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

TVA Region (Tennessee, western Virginia, northeastern Georgia, northern Alabama, and northern Mississippi)



Applicable RTOs: None today; under SMD, TVA is assumed to establish its own RTO (or equivalent)

Retail Rate Regulation: All cost of service

The TVA region is an exporter in both cases, with increased exports in the SMD case.[9] In the near term, both coal and gas generation increase. In the long term, the additional generation is primarily from gas combined cycles. The increased ability to reach more distant markets leads to an increase in wholesale prices; however, TVA continues to have the lowest wholesale prices in the Southeast.

Consumer prices in the region are set by cost-of-service regulation. Higher wholesale revenues lead to slightly lower prices for native customers.

Table 3.14. TVA Region: Model Results

Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	0	1	0	1	1	0	0	1	0
Exports	7	6	9	11	9	15	4	3	7
Generation	191	210	230	195	213	237	4	2	7
Coal	121	132	151	124	131	153	2	0	2
Natural Gas	7	13	12	8	16	17	2	3	5
Other	63	65	67	63	65	67	0	-1	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.2	0.2	0.2	—	—	—
Wholesale Prices	29	35	33	30	36	35	4%	2%	7%
Retail G&T Prices	35	35	36	35	35	36	0%	0%	0%
	Billion Dollars								
Consumer G&T Costs	5.9	6.6	7.5	5.9	6.6	7.5	0%	0%	0%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

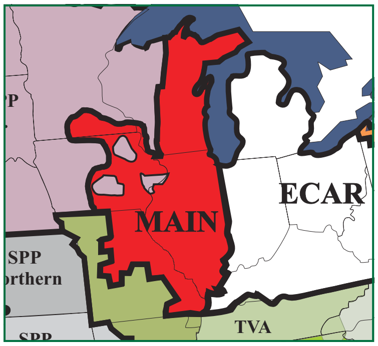
Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

[9]The TVA Region, as modeled, consists of approximately 40,000 megawatts of generating capability, including the TVA's approximately 31,500 megawatts. For modeling purposes, we assumed that the short-term energy markets would operate in an economically efficient fashion without respect to the restrictions on TVA selling outside its historical markets (i.e., outside the "fence"). Thus, the model does not discriminate between the TVA assets and the other assets in the TVA region.

Discussion of Regional Impacts

MAIN Region (Illinois, eastern Wisconsin, northern Michigan, southeastern Minnesota, eastern Iowa, and eastern Missouri)



Applicable RTOs: MISO, PJM

Retail Rate Regulation: 60 percent cost of service; 40 percent competitive

The MAIN region is both an importer and exporter of power. Imports increase slightly and exports increase substantially in the SMD case with the elimination of intra-RTO transmission fees and pancaking. The exports are produced primarily from coal-fired generating units.

In the Non-SMD case, the MAIN region has low wholesale prices in comparison to neighboring regions. In the SMD case wholesale prices rise due to greater commerce, as prices are bid up by sales to higher priced MAAC and other regions. Consumer prices rise, but not as much as the wholesale price.

Table 3.15. MAIN Region: Model Results

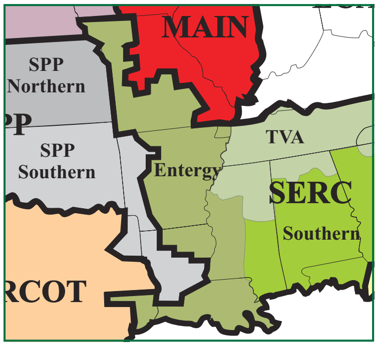
Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	3	2	3	7	6	8	4	3	5
Exports	2	5	3	23	26	18	21	21	14
Generation	287	317	334	304	335	344	18	18	10
Coal	166	182	192	183	193	199	17	12	6
Natural Gas	7	19	24	8	25	28	1	7	4
Other	114	116	117	114	116	117	0	0	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.2	0.2	0.1	—	—	—
Wholesale Prices	27	33	34	30	35	35	10%	7%	4%
Retail G&T Prices	37	39	39	39	40	40	4%	3%	3%
	Billion Dollars								
Consumer G&T Costs	10.0	11.3	12.1	10.3	11.7	12.4	4%	3%	3%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

Entergy Region (western Missouri, eastern Arkansas, and northeastern Louisiana)



Applicable RTOs: SETrans

Retail Rate Regulation: All cost of service

The Entergy region is both an importer and exporter of power. In the SMD case, both imports and exports increase with the removal of pancaked transmission rates. Wholesale prices fall for the region as more expensive generation is displaced by imports.

Consumer prices are cost-of-service based throughout the region. Some of the exports are from nonutilities, so any change in their profits does not affect consumer prices. The generation component of rates falls by $0.3 to $0.4/MWh, but the decrease is offset by SMD implementation costs of almost the same magnitude. There is little change in the transmission component of rates for the Entergy region.

Table 3.16. Entergy Region: Model Results

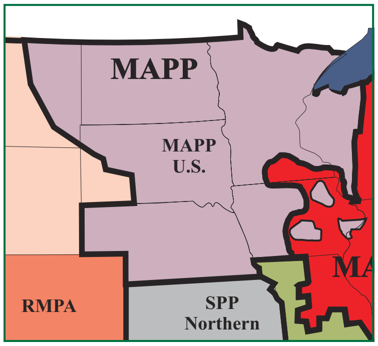
Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	12	13	12	22	21	19	10	8	6
Exports	2	2	3	10	9	11	7	7	9
Generation	157	176	192	155	175	195	-2	0	3
Coal	59	64	87	59	64	87	0	0	1
Natural Gas	54	66	58	52	65	61	-3	-1	3
Other	44	46	47	44	46	47	0	0	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.3	0.2	0.2	—	—	—
Wholesale Prices	31	36	35	30	35	35	-2%	-3%	-1%
Retail G&T Prices	48	49	50	48	49	49	0%	0%	0%
	Billion Dollars								
Consumer G&T Costs	7.6	8.7	9.4	7.6	8.6	9.4	0%	0%	0%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

MAPP Region (North Dakota, most of Minnesota, most of South Dakota, western Iowa, Nebraska, and eastern Montana)



Applicable RTOs: MISO

Retail Rate Regulation: All cost of service

MAPP is a net exporter. In the Non-SMD case, market inefficiencies prevent some of the available low-cost power from reaching more distant load centers. As a result, net exports increase in the SMD case, especially in the early years.

In the Non-SMD case, MAPP is among the regions with the lowest wholesale prices. Wholesale prices rise in the near term with SMD due to the ability to reach to higher priced markets, but the impact moderates within a few years.

Retail prices, which currently are based on cost-of-service regulation, are reduced in the SMD case. Larger wholesale revenue (due to increases in both export volumes and export prices) gets credited back to consumers. Transmission fees collected through wholesale commerce decrease in the SMD case, but the fees are not large enough to have an appreciable effect on retail prices.

Table 3.17. MAPP Region: Model Results

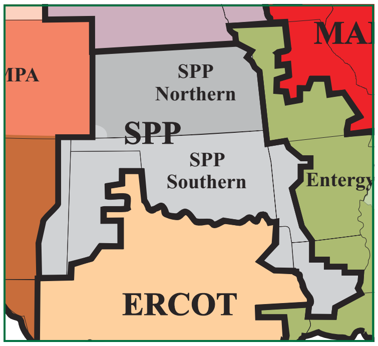
Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	1	3	3	7	9	11	5	7	8
Exports	7	9	8	26	21	21	20	12	13
Generation	192	214	229	208	220	235	16	6	6
Coal	139	151	161	156	159	170	16	7	9
Natural Gas	6	14	19	5	12	15	-1	-1	-3
Other	47	49	50	48	49	50	1	0	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.2	0.2	0.2	—	—	—
Wholesale Prices	27	36	36	30	35	36	10%	0%	-1%
Retail G&T Prices	43	41	41	41	40	41	-3%	-2%	-1%
	Billion Dollars								
Consumer G&T Costs	7.4	7.8	8.5	7.2	7.7	8.4	-3%	-2%	-1%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

SPP Region (Kansas, Oklahoma, western Arkansas, northwestern and central Louisiana, northwestern Texas, and eastern New Mexico)



Applicable RTOs: MISO

Retail Rate Regulation: All cost of service

SPP imports and exports power, and both increase in the SMD case with the elimination of pancaked fees and market inefficiencies. As part of MISO, parties in SPP can buy and sell across a large area with minimal transaction costs.

Wholesale prices are projected to decline substantially in the SMD case. Because the region has cost-of-service retail rates, the cost of wholesale power affects consumers only through changes in import costs and profits from export sales. The net effect in SPP is a slight reduction in retail generation and transmission rates. The cost of SMD implementation is relatively small, as is the change in wholesale transmission revenue.

Table 3.18. SPP Region: Model Results

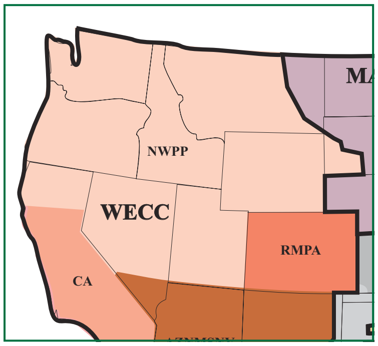
Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	3	6	4	8	12	10	5	6	6
Exports	6	5	6	11	10	14	6	6	9
Generation	204	220	237	205	220	240	1	0	3
Coal	145	150	173	145	150	175	1	0	2
Natural Gas	44	54	48	44	54	49	0	-1	1
Other	15	16	15	16	16	16	1	1	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.2	0.2	0.2	—	—	—
Wholesale Prices	32	39	38	30	36	35	-4%	-8%	-7%
Retail G&T Prices	42	43	43	41	43	42	-1%	-1%	-1%
	Billion Dollars								
Consumer G&T Costs	7.9	9.2	9.7	7.8	9.1	9.7	-1%	-1%	-1%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

NWPP Region (Washington, Oregon, Idaho, most of Montana, western South Dakota, Wyoming, Utah, most of Nevada, and part of northern California)



Applicable RTOs: RTO West

Retail Rate Regulation: All cost of service

NWPP is a net exporter of power to other regions in the West. There is a modest increase in exports and imports in the SMD case when obstacles to commerce are removed. The generation displaced is oil- or gas-fired; all excess hydroelectricity is exported in both cases.

Market-based wholesale prices fall in the SMD case. California markets are the main outlets for NWPP exports, and the wholesale prices in the two regions tend be to linked.

Federal preference power continues to be sold on a cost-of-service basis below the indicated competitive wholesale market prices in both cases. There is little change in utility profits from inter-regional exports between cases, and consumer generation prices remain roughly constant. However, the transmission component of consumer prices increases slightly in the SMD case, because transmission revenue from wholesale customers outside the region is lost when the pancaked transmission fees are removed. The SMD implementation costs contribute to the rest of the increase in consumer generation and transmission rates.

Table 3.19. NWPP Region: Model Results

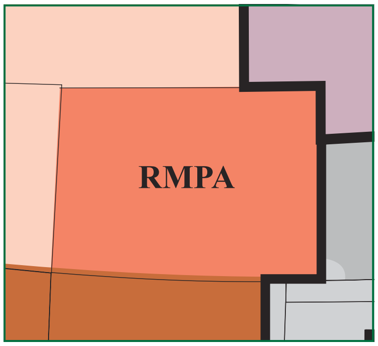
Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	6	10	11	7	11	12	1	2	2
Exports	27	28	34	28	30	36	1	2	2
Generation	283	315	351	282	315	351	-1	0	1
Coal	89	95	123	89	95	123	0	0	0
Natural Gas	43	68	75	42	68	76	-1	0	1
Other	152	153	153	152	152	152	0	-1	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.4	0.4	0.3	—	—	—
Wholesale Prices	41	42	43	39	41	42	-4%	-3%	-3%
Retail G&T Prices	38	44	45	38	44	46	1%	1%	1%
	Billion Dollars								
Consumer G&T Costs	9.2	11.9	13.6	9.3	12.0	13.8	1%	1%	1%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

RMPA Region (Colorado)



Applicable RTOs: Translink West

Retail Rate Regulation: All cost of service

RMPA is both an import and exporter of power, but it becomes more of an exporter over time. RMPA' s historical trading pattern with AZN continues over the forecast period.

Wholesale prices are lower in the near term in the SMD case, then become higher over time. The reduction of barriers to commerce in the SMD case means that exports can reach more expensive markets outside the region.

Consumer prices are based on cost-of-service regulation. The primary source of increased prices in the near term is the RTO costs. Over time, revenue from exports offsets the SMD implementation costs, and retail generation and transmission prices are slightly lower in the SMD case.

Table 3.20. RMPA Region: Model Results

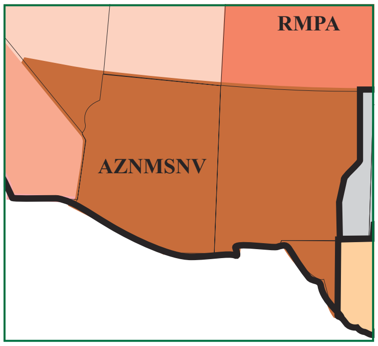
Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	5	1	2	6	2	3	1	1	1
Exports	3	9	9	4	10	10	1	1	1
Generation	65	86	94	65	86	94	0	1	0
Coal	50	72	79	50	72	79	0	0	0
Natural Gas	11	10	10	11	10	10	0	1	0
Other	5	4	4	4	4	5	0	0	1
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.5	0.4	0.3	—	—	—
Wholesale Prices	39	38	39	38	39	40	-2%	2%	2%
Retail G&T Prices	44	45	45	44	45	45	1%	-1%	0%
	Billion Dollars								
Consumer G&T Costs	2.7	3.2	3.7	2.7	3.2	3.6	1%	-1%	0%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

AZN Region (southern Nevada, Arizona, most of New Mexico, and a small area of western Texas)



Applicable RTOs: WestConnect, RTO West

Retail Rate Regulation: 60 percent competitive; 40 percent cost of service

AZN is a significant power exporter, in part because it has several large power plants that are jointly owned by utilities in AZN and California. This trend is projected to continue in the future, with the construction of new power plants that will sell some of their output into the California market, as the lowest cost option for the combined AZN-California area. With the reduction in transmission hurdles as a result of SMD, AZN's exports increase and wholesale prices in AZN rise.

Roughly 60 percent of retail sales in the AZN region are based on competitive prices. As a result, consumer prices rise with the increase in wholesale prices. In addition, reduced transmission revenues from wholesale transactions increases consumer prices by $0.2 to $0.5/MWh. The estimated SMD implementation cost of $0.3/MWh also contributes to higher prices.

Table 3.21. AZN Region: Model Results

Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	2	1	1	3	1	1	2	0	0
Exports	39	56	54	60	70	70	21	14	15
Generation	160	196	210	179	210	226	20	14	16
Coal	78	118	133	78	118	133	0	0	0
Natural Gas	37	32	31	56	46	47	20	14	16
Other	46	46	46	46	46	46	0	0	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0.3	0.3	0.2	—	—	—
Wholesale Prices	37	39	38	38	39	39	1%	1%	3%
Retail G&T Prices	50	52	52	52	54	53	3%	3%	3%
	Billion Dollars								
Consumer G&T Costs	5.6	6.6	7.3	5.7	6.8	7.6	3%	3%	3%

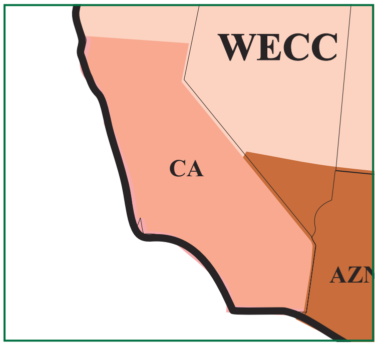
Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.

Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.

Source: POEMS Model scenario outputs.

Discussion of Regional Impacts

CA Region (most of California)



Applicable RTOs: CAISO

Retail Rate Regulation: All competitive

California is currently a major importer of power, and it is projected to remain so over time in both cases. In the SMD case, with lower fees and lower hurdles to trade, California increases its imports, displacing more expensive gas-fired generation. The CAISO already has set up many elements of SMD, and the additional implementation costs are projected to be small.

The increased ability to trade reduces wholesale prices in the region. Lower prices flow directly through to consumers, because the region has competitive retail rates.[10] Although retail customers may not literally face the fluctuating time-of-day wholesale prices, their rates will reflect underlying conditions in wholesale markets.

Table 3.22. CA Region: Model Results

Projection	Non-SMD			SMD			Change from Non-SMD to SMD		
	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term	Near Term	Mid-Term	Long Term
	Billion Kilowatthours								
Imports	57	82	83	76	96	99	18	14	16
Exports	0	0	0	0	0	0	0	0	0
Generation	223	231	259	204	217	244	-19	-14	-15
Coal	26	26	26	26	26	26	0	0	0
Natural Gas	96	101	125	78	88	110	-19	-14	-15
Other	101	103	108	101	103	108	0	0	0
	Dollars per Megawatthour								
SMD Implementation Cost	—	—	—	0	0	0	—	—	—
Wholesale Prices	41	45	45	39	43	43	-4%	-4%	-4%
Retail G&T Prices	50	55	56	49	54	55	-2%	-1%	-1%
	Billion Dollars								
Consumer G&T Costs	12.6	15.5	17.4	12.4	15.3	17.2	-2%	-1%	-1%

Near term: annual average, 2005-2010; Mid-term: annual average, 2011-2015; Long term: annual average, 2016-2020.
Notes: All dollar amounts are in real 2002 dollars. Changes are rounded to the nearest billion kilowatthour or nearest whole percent. Some figures may not add to totals shown due to independent rounding.
Source: POEMS Model scenario outputs.

[10] This study does not take into consideration the disputed existing long-term contracts in California or the repeal of retail choice in the State. Attention to all of the special circumstances in each region was not possible in the time available for this study.

Changes in Usage of Transmission Networks Under SMD

The MAPS model, with its great detail concerning the existing generation and transmission infrastructure, enables analysts to understand how changes in the institutional framework for managing the Nation's transmission assets would affect the usage of those assets, and how those changes would affect both participants in wholesale markets and retail electricity consumers. *Note: The MAPS-based results presented below are to be understood as occurring within the envelope of projections defined earlier by POEMS. That is, the economic benefits projected by MAPS from increased commerce across certain interfaces are subsumed within the aggregate results projected by POEMS.*

The MAPS Model

GE-MAPS™ (Multi-Area Production Simulation) is a security-constrained production simulation program incorporating a detailed transmission constraints model. The MAPS program provides a highly granular physical model of all the regions in the Eastern Interconnection (EI) and the Western Electricity Coordinating Council (WECC) system, meaning that it has detailed information on power plants, transmission lines, and other engineered features of the system's infrastructure. It applies a DC representation of an AC power flow to the transmission system during the program's commitment and dispatch routines. With this basis, the MAPS program simulates operation of the system, striving for the lowest system-wide production cost. Each week it finds the low cost commitment schedule and then runs an hourly dispatch to optimize plant operations to meet projected system load.[11]

Assumed Effect of RTO Formation on Inter-Regional Transactions

Modeling the Non-SMD case required a representation of inefficiencies in the existing markets. This was done through the use of "hurdle rates" assigned to flows between control areas and between RTO regions. The hurdle rates represent the total barrier, or economic hurdle, that must be overcome before energy will be traded across a transmission interface. As such, hurdle rates include both the real costs (such as wheeling rates) that are in existence and "other factors" that may inhibit commerce (such as minimum savings thresholds assigned by power buyers or sellers, inability to identify all beneficial transactions due to inadequate information, and difficulty in arranging transmission access, among others).

The schedule for this study did not permit an independent determination of hurdle rates for all the regions of interest. Consequently, we applied representative hurdle rates previously determined by GE Power Systems energy Consulting (GE-PSEC) for regional studies performed in both the Eastern Interconnection and WECC systems.[12] In those studies, effective hurdle rates were calculated by comparing actual power exchange with the amount of power exchange that would be expected to result from optimal operation of the power system. The optimum transactions were determined by applying MAPS simulation using historical loads, resources, and fuel prices. The resulting transfers between control areas were compared with the equivalent historical values. In all cases, the volume of actual inter-regional transactions fell below that predicted for the optimized system, indicating that barriers to commerce did exist. To quantify the extent of the barriers, economic costs (hurdle rates) were assigned to power flows between control areas until the projected interchange matched that observed historically.

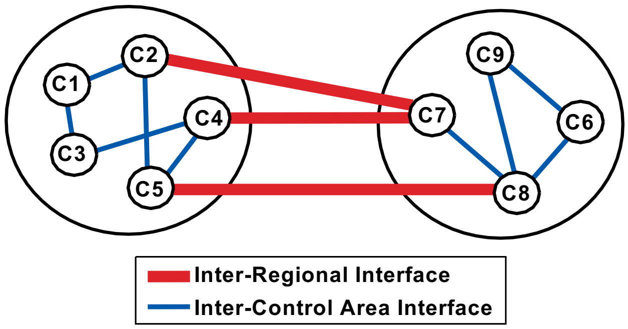
In the study of the Northeast it was assumed that each of the existing RTOs operated as a single control area, so that we were primarily examining the flows between the RTOs. In the Southeast the RTOs are not currently in existence, and so it was important to look not only at the flows between regions but also at the flows between control areas, as illustrated in Figure 3.20. In addition, an effort was made to match the regional energy production by unit type to their corresponding historical values.

Based on these previous studies we assumed a \$10/MWh hurdle rate between control areas and RTOs for the commitment of the Eastern Interconnection (EI). A \$5/MWh rate was assumed in the dispatch process. Within the existing RTOs (ISO-NE, NYISO, and PJM) the hurdle rate was assumed to be zero, because these regions have wholesale power markets and do not assess wheeling charges for intra-RTO transactions.

[11] Additional description of MAPS is provided in Appendix B for this report. See U.S. Department of Energy, *Appendices to Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design* (May 2003).

[12] These studies included work performed by GE-PSEC in the Northeast for the New York ISO and ISO New England, in the Southeast for SEARUC, and in WECC for a confidential client.

Figure 3.20. Illustration of Inter-Control Area and Inter-Regional Interfaces



WECC has traditionally had relatively higher levels of wholesale commerce, implying that existing trade barriers in the West are lower than in the Eastern Interconnection. (This was confirmed in an earlier MAPS study.) WECC hurdle rates were set at $5/MWh and $3/MWh for commitment and dispatch, respectively. No hurdle rates were assumed between control areas in the existing California ISO.

With the introduction of the RTOs the hurdle rates between the control areas within an RTO were eliminated. An entire RTO is assumed to operate as a single control area with full price transparency and without intra-regional wheeling charges. A small hurdle rate is assumed to remain between the RTOs to represent the residual wheeling and "seams" issues. The SMD case assumed inter-RTO hurdle rates of $4/MWh and $2/MWh for commitment and dispatch respectively in both the Eastern Interconnection and WECC.

SMD and Sensitivity Cases

In the SMD case it was assumed that the formation of an RTO would result in improved efficiency in the operation of the transmission lines within the RTO footprint. Based on estimates from a study performed in the Northeast (NERTO study) we assumed an additional 5 percent transfer capacity on interfaces between all control areas within new RTOs. The first sensitivity case (*SMD w/ 10%T*) assumes that the RTO formation under SMD would result in increased transmission investment that would remove any significant bottlenecks, leading to a 10 percent increase in transmission capability at limiting interfaces between control areas. The second sensitivity case (*SMD w/o 5%T*) removes the assumption of the 5 percent improvement in transmission capability between control areas. The third sensitivity case (*SMD w/o GEI*) removes the assumption of improved generator efficiency from the SMD case. Table 3.23 summarizes the assumptions for the Non-SMD, SMD, and sensitivity cases.

Impacts of SMD on Transmission Utilization

The elimination of obstacles to commerce produces a significant increase in the use of the transmission system. The MAPS model includes tens of thousands of interconnection points and transmission lines and examines flow limits for thousands of lines under normal and contingency constraints. To illustrate the effect of SMD on transmission system usage, MAPS model results for the Eastern Interconnection and WECC are summarized below.

Table 3.23. Assumptions for the MAPS Non-SMD, SMD, and SMD Sensitivity Cases

MAPS Analysis Case	Region	Hurdle Rates: Inter-Control Area Commitment	Hurdle Rates: Inter-Control Area Dispatch	Hurdle Rates: Inter-Regional Commitment	Hurdle Rates: Inter-Regional Dispatch	10%T[a]	5%T[b]	GEI[c]	Years Simulated
Non-SMD	EI	10	5	10	5	No	No	No	2005, 2007
	WECC	5	3	5	3	No	No	No	2005, 2007
SMD	EI	0	0	4	2	No	Yes	Yes	2005, 2007
	WECC	0	0	4	2	No	Yes	Yes	2005, 2007
SMD w/ 10%T	EI	0	0	4	2	Yes	Yes	Yes	2005
	WECC	0	0	4	2	Yes	Yes	Yes	2005
SMD w/o GEI	EI	0	0	4	2	No	Yes	No	2005
	WECC	0	0	4	2	No	Yes	No	2005
SMD w/o 5%T	EI	0	0	4	2	No	No	Yes	2005
	WECC	0	0	4	2	No	No	Yes	2005

[a]10% improvement on all limiting interfaces.
[b]5% improvement in inter-control area interface limits.
[c]Generator Efficiency Improvements (2% for coal units, 4% for gas-steam units).

Figure 3.21 shows the change in energy flowing between NERC subregions in 2005. The total amount of energy exchanged between the subregions in the Eastern Interconnection more than doubles when the hurdles are reduced in the SMD case. (As a point of reference, total annual electricity consumption in the Eastern Interconnection is approximately 2,700 terawatthours [TWh].) For WECC the corresponding increase is about 30 percent.

Figure 3.22 shows the change in power flows between all the control areas in both the Eastern Interconnection and WECC in 2005, including not only the energy flowing between the NERC subregions but also the interchanges between control areas within the subregions. In the SMD case, the total energy transferred increases by about 25 percent.

The following charts illustrate changes in the utilization of specific transmission interfaces under SMD. Figure 3.23 shows the hourly flow for a year (2005) across the Southern-Florida interface, sorted according to the quantity of power transferred during each hour. In the Non-SMD case the interface flow is at the limit about 30 percent of the time. Approximately 10 percent of the time, the line is projected to be essentially unused. In the SMD case the line is used at its limit approximately 70 percent of the time. Also, in the SMD case, the line is used to some extent in 95 percent of the hours of the year. Consistent with the assumptions discussed above, the limit is 5 percent higher in the SMD case. Figure 3.23 demonstrates that, under SMD, the existing transmission facility would be used much more productively, with substantial benefit for wholesale buyers and the consumers they serve. Projected usage of an interface at its capacity for such a large fraction of the year also implies that there may be opportunity for economic investment to increase the interface's transfer capacity.

Figure 3.23 shows a large increase in energy flows across the Southern to Florida transmission interface resulting from the introduction of SMD. The assumed 5 percent increase in the interface limit contributes only a small amount to the total benefit (13 percent of the total increase in energy flow). The majority of the increase in energy flow comes from the removal of obstacles to commerce.

The economic value of the commerce across the Southern to Florida interface was calculated for both the Non-SMD and SMD cases by multiplying the hourly flow times the average spot price at the receiving end of the interface. The resulting number is a measure of the value of the delivered energy. When the operational inefficiencies are reduced in the SMD case, energy imports increase

Figure 3.21. EI and WECC Inter-Regional Power Flows, 2005

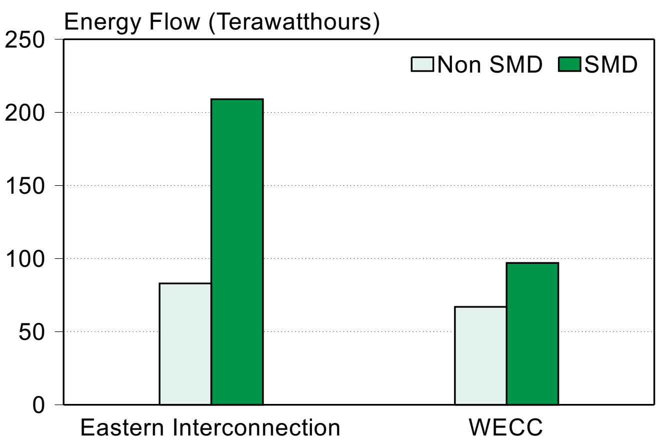


Figure 3.22. EI and WECC Inter-Control Area Power Flows, 2005

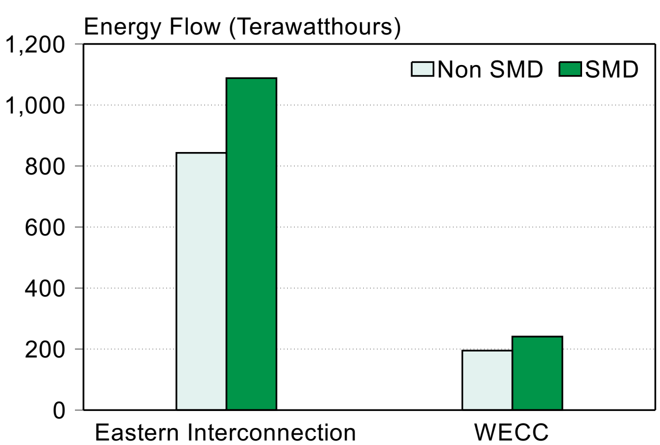
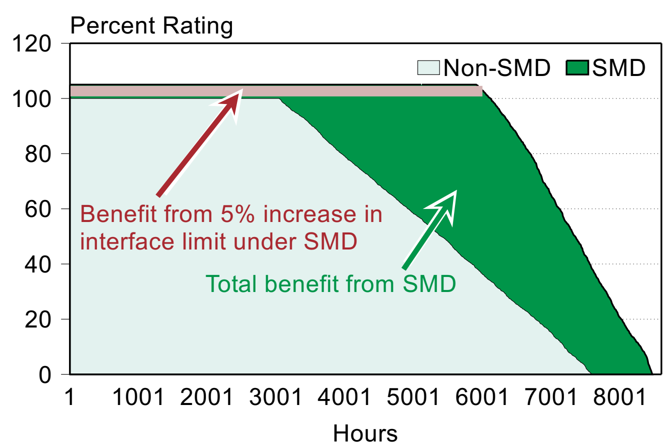


Figure 3.23. Power Flows Across the Southern-Florida Interface, 2005



by 42 percent (Table 3.24). At the same time, spot prices in Florida drop, in part due to increased operating efficiencies induced by SMD elsewhere in Florida. The result is an increase of over $150 million in the value of the energy delivered over the interface in 2005.

Figure 3.24 shows similar results for the ECAR to VACAR interface. Here the projected usage level of the interface changes from full utilization 7 percent of the time to full utilization almost 30 percent of the time. The Non-SMD case shows zero flow over 30 percent of the time, whereas the SMD case has essentially no hours when the line is not in use. Transfers projected in the Non-SMD case represent only 33 percent of the maximum possible. The SMD case shows transfers at 76 percent of the maximum possible. Further, the assumed 5 percent increase in the ECAR-VACAR interface limit contributes only a small amount (3 percent of the total increase in energy flow) to the total benefit. The majority of the projected increase in energy flow comes from removal of barriers to trade through SMD.

Table 3.25 shows that the primary impact in the SMD case is on the flows from ECAR to VACAR. Although there is some projected commerce in the opposite direction, the flows into VACAR more than double, and the spot price at the receiving end drops by more than 25 percent. The total effect is a projected 78 percent increase in the value of commerce across the interface (summing the values for the flows in both directions).

As a final example in the East, Figure 3.25 shows hourly power flows on the Entergy-SPP interface. The curve for the Non-SMD case shows minimal utilization of the interface; the SMD case shows the interface used to its limit more than 50 percent of the time and some energy flowing all of the time in one direction or the other. For this interface, line usage increases by 80 percent. Table 3.26 shows that, in the SMD case, after summing the values of the energy flows in both directions, the projected total value of commerce across the

Figure 3.24. Power Flows Across the ECAR-VACAR Interface, 2005

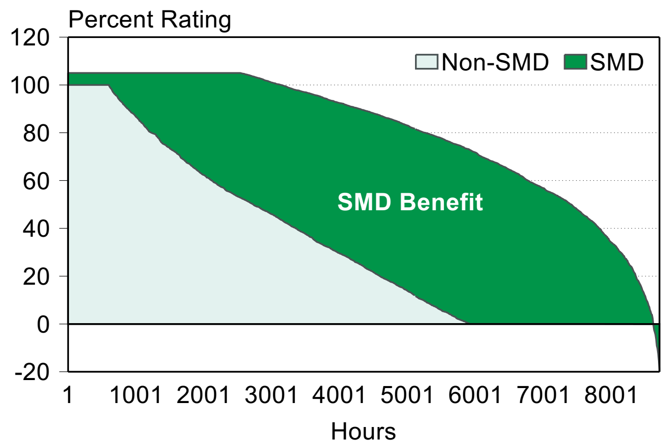


Table 3.24. Power Flows Across the Southern-Florida Interface, 2005

Projection	Non-SMD Case	SMD Case	Difference Under SMD	Percent Change Under SMD
Southern to Florida Energy Flow (Gigawatthours)	16,160	22,942	6,782	42%
Average Receiving End Spot Price (Dollars per Megawatthour)	38.34	33.61	-4.73	-12%
Value of Delivered Energy (Thousand Dollars)	619,551	771,012	151,461	24%

Table 3.25. Power Flows Across the ECAR-VACAR Interface, 2005

Projection	Non-SMD Case	SMD Case	Difference Under SMD	Percent Change Under SMD
VACAR to ECAR				
Energy Flow (Gigawatthours)	9	70	61	678%
Average Receiving End Spot Price (Dollars per Megawatthour)	32.44	19.71	-12.73	-39%
Value of Delivered Energy (Thousand Dollars)	292	1,380	1,088	373%
ECAR to VACAR				
Energy Flow (Gigawatthours)	7018	16,982	9,964	142%
Average Receiving End Spot Price (Dollars per Megawatthour)	32.21	23.72	-8.49	-26%
Value of Delivered Energy (Thousand Dollars)	226,056	402,710	176,654	78%
Total Value of Delivered Energy (Thousand Dollars)	**226,348**	**404,090**	**177,742**	**78%**

Table 3.26. Power Flows Across the Entergy-SPP Interface, 2005

Projection	Non-SMD Case	SMD Case	Difference Under SMD	Percent Change Under SMD
Entergy to SPP				
Energy Flow (Gigawatthours)	167	2,036	1,869	1,119%
Average Receiving End Spot Price (Dollars per Megawatthour)	32.63	30.88	-1.75	-5%
Value of Delivered Energy (Thousand Dollars)	5,449	62,871	57,422	1,054%
SPP to Entergy				
Energy Flow (Gigawatthours)	480	1,987	1,507	314%
Average Receiving End Spot Price (Dollars per Megawatthour)	28.98	16.79	-12.19	-42%
Value of Delivered Energy (Thousand Dollars)	13,912	33,357	19,445	140%
Total Value of Delivered Energy (Thousand Dollars)	**19,361**	**96,228**	**76,867**	**397%**

Entergy-SPP interface quadruples, to more than $75 million.

Turning to the West, Figures 3.26 and 3.27 show the projected changes in flows over two interfaces, Arizona-Northwest and Arizona-California. The increase in transmission usage is not as dramatic as in the East, because the barriers to commerce removed by SMD are smaller. Nevertheless, both charts show increased flows for most hours. Table 3.27 shows that, for the Arizona-Northwest interface, the major effect of the SMD case is to increase the projected energy flows from Northwest into Arizona. The energy delivered more than doubles, and the value of commerce over the interface increases by a net 70 percent. The spot price in Arizona increases, due to a substantial increase in exports from Arizona to California (Table 3.28). The exports to California are large enough to more than offset the downward pressure on wholesale prices associated with the imports from the Northwest. However, Figure 3.27 and Table 3.28 show also that SMD produces only about a 10 percent increase in the value of commerce over the Arizona-California interface, because that interface is already heavily used in the Non-SMD case.

Figure 3.25. Power Flows Across the Entergy-SPP Interface, 2005

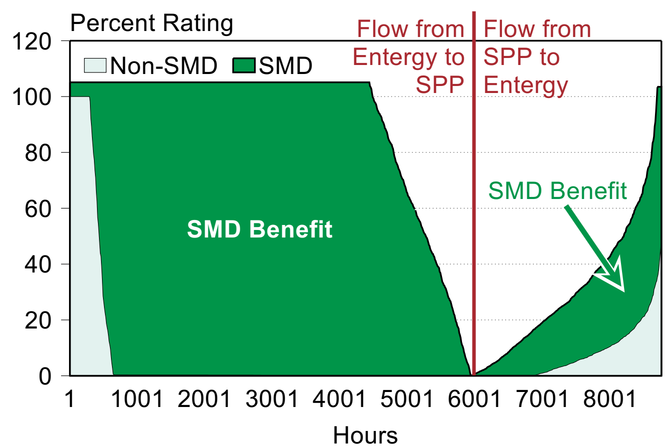


Figure 3.26. Power Flows Across the Arizona-Northwest Interface, 2005

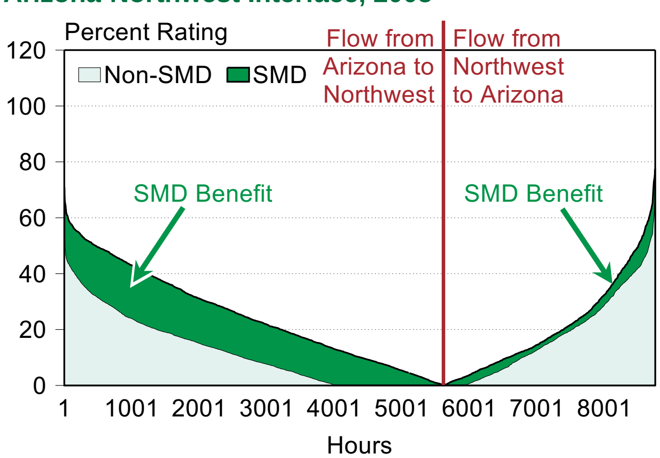


Figure 3.27. Power Flows Across the Arizona-California Interface, 2005

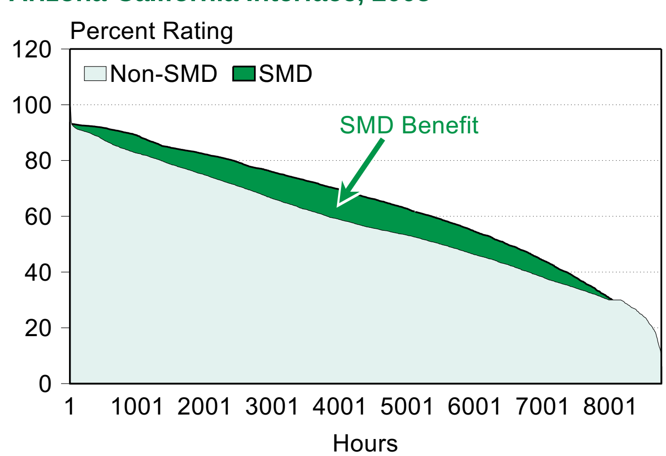


Table 3.27. Power Flows Across the Arizona-Northwest Interface, 2005

Projection	Non-SMD Case	SMD Case	Difference Under SMD	Percent Change Under SMD
Arizona to Northwest				
Energy Flow (Gigawatthours)	571	683	112	20%
Average Receiving End Spot Price (Dollars per Megawatthour)	36.23	35.93	-0.3	-1%
Value of Delivered Energy (Thousand Dollars)	20,686	24,543	3,857	19%
Northwest to Arizona				
Energy Flow (Gigawatthours)	670	1,423	753	112%
Average Receiving End Spot Price (Dollars per Megawatthour)	27.96	29.8	1.84	7%
Value of Delivered Energy (Thousand Dollars)	18,731	42,410	23,679	126%
Total Value of Delivered Energy (Thousand Dollars)	**39,417**	**66,953**	**27,563**	**70%**

Table 3.28. Power Flows Across the Arizona-California Interface, 2005

Projection	Non-SMD Case	SMD Case	Difference Under SMD	Percent Change Under SMD
Arizona to California Energy Flow (Gigawatthours)	50,027	55,714	5,687	11%
Average Receiving End Spot Price (Dollars per Megawatthour)	33.56	33.51	0.05	0%
Value of Delivered Energy (Thousand Dollars)	1,678,868	1,866,813	187,945	11%

Sensitivity Cases

Figures 3.28 and 3.29 show projected energy flows between NERC subregions and between control areas in 2005 for the entire United States in the five cases used in this analysis. Although there is some slight variation between the SMD case and the sensitivity cases as a result of the different assumptions about transmission capability and generator efficiency, most of the projected increase in electricity transfers results from the reduction of trade barriers.

Figure 3.28. Comparison of Inter-Control Area Power Flows in Five Cases, 2005

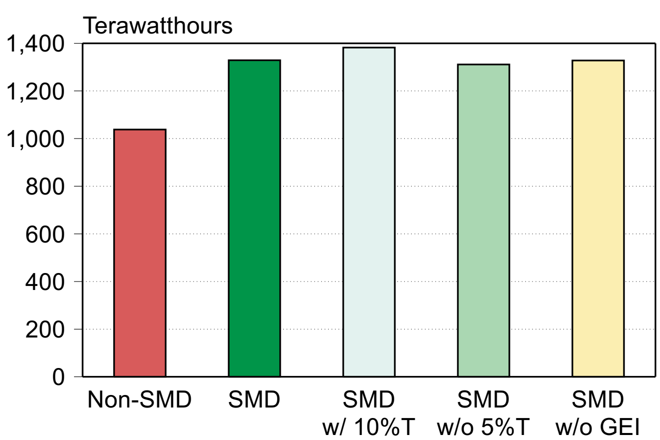
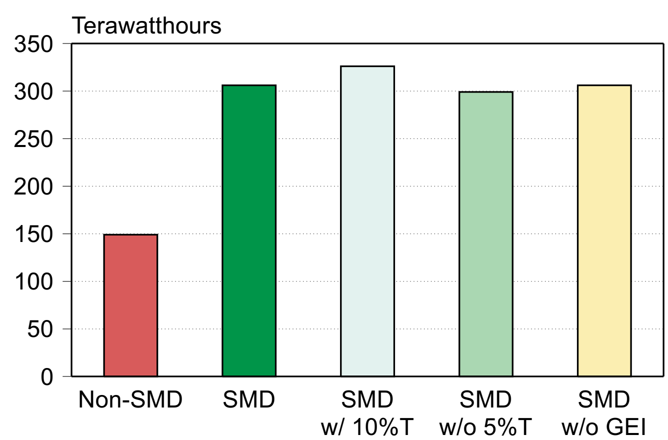


Figure 3.29. Comparison of Inter-Regional Power Flows in Five Cases, 2005



4. Estimating the Impacts of SMD: Qualitative Analysis

This chapter discusses several categories of impacts that are not suited to exploration using the MAPS and POEMS models, at least within the time and budget limitations of this analysis.

Impacts on the Reasonableness of Electricity Prices and Potential Need for Market Power Mitigation

SMD and the Potential for Instability in Wholesale Electricity Markets

From mid-2000 to mid-2001, California and the broader Western market experienced electricity shortages and unprecedented high prices for bulk power. The electricity shortages led to some rolling blackouts and to serious economic harm to a substantial number of wholesale and retail market participants.

There are two leading interpretations of the root causes of this experience. The first is that the high wholesale electricity prices were caused by scarcity of bulk power as a commodity. This is the "Perfect Storm" interpretation, which maintains that a combination of conditions came together to create unprecedented scarcity, resulting in unprecedented high prices. The second interpretation is that market scarcity was important, and that suppliers were able to leverage that scarcity by exercising market power in the dysfunctional California spot markets. This "market power" interpretation maintains that market manipulation contributed significantly to the disruption.

The two views are not mutually exclusive, and both are dependent on the premise that underlying scarcity plagued California and the broader Western market during the 2000-2001 period. The scarcity resulted from many factors, including a relative lack of building new generation capacity in the preceding 10 years, a poor hydro year that limited hydroelectric production, a dysfunctional spot market that was encumbered by inefficient and restrictive rules, a California State restructuring decision to rely on energy markets alone without any sort of planned generation reserve requirement, and perhaps most importantly a regulatory rule that inhibited utilities from buying power in advance of the daily spot market. Given that the State's three large investor-owned utilities previously had divested about half of their generating capacity as part of the State's restructuring program, this meant that the utilities were forced to buy substantial amounts of power from the short-term spot markets—for the most part without the benefit of hedging through long-term contracts.

The SMD proposal seeks to address the scarcity problem preemptively in several ways. However, each of these components could be implemented independent of Standard Market Design.

- *Regional resource adequacy requirements.* FERC proposed to work with the States to establish minimum requirements and to create regional markets for reserve capacity or the demand-side equivalent. Creation of such markets would aid reliance on long-term contracts and minimize over-dependence on short-term spot markets. As long as these basic concerns are met, it appears that FERC is prepared to leave the details to the States. However, where RTOs span several States, significant and effective interstate cooperation would be required.

- *Regional transmission planning.* Inadequate transmission resources can contribute to or exacerbate an underlying scarcity of regional generation capacity. SMD addresses this by assigning responsibility for coordination of regional transmission planning to the RTO. Further, "regional transmission planning" is a shorthand term for resolving a cluster of interactive planning issues, including guidelines for siting new generation and economically efficient use of alternatives to new transmission lines, such as distributed generation, energy efficiency, demand response programs, and improved real-time grid management. Here too, RTOs would have to work with the States, and the States would have to work with each other, in the development of workable regional requirements and procedures. FERC, it appears, would give the RTOs substantial latitude to work with the States in this area.

- *Facilitation of Grid-Related Investment.* FERC clearly intends for RTOs to be proactive, and to be proactive itself, in facilitating investment to meet needs identified in RTO transmission expansion plans. Here again it is important to realize that "transmission expansion plan" is a shorthand term for transmission lines *and* a wide array of technological and market-related alternatives to such lines. One of the responsibilities of the RTO would be to foster fair and open competition between all feasible alternatives.

- *Facilitation of Demand Response Capability.* Although demand response has arguably been addressed in the preceding paragraphs, especially "regional resource adequacy requirements" and "regional transmission planning," it is sufficiently important here to merit explicit mention as an antidote to scarcity of generation capacity.

Market Monitoring and Mitigation of Market Power

FERC proposes to require each RTO to establish a market monitoring and market power mitigation program. These requirements are based on substantial experience with similar programs that have been instituted by PJM, the New York ISO, and ISO-New England. Those programs have good and proven track records. They include several safeguards:

- Close, daily monitoring of the region's day-ahead and real-time markets by an independent party

- Reliability Must Run (RMR) agreements for individual generating units that have localized market power

- A safety net price cap of $1,000 per MWh

- A regional resource adequacy requirement

- The potential to adjust a generator's bid downward automatically if it is out of line with its historical bidding behavior.

The monitoring and mitigation proposed under SMD are easier to implement in an organized regional short-term market administered by an RTO (or ITP) than they would be in the less structured bilateral short-term markets that characterize much of the industry today. The information on bids and transparent prices is available to the RTO monitor on a real-time basis. The RTO monitor would be able to detect and respond to unusual pricing and bidding behavior much more quickly than would be possible in a bilateral market. A potential disadvantage of the bid-cap components of FERC's proposal is that if they are overused they may suppress prices, especially at the time of peak demand, and thereby create a disincentive for needed investment in generation. This is always a concern in any regulatory price cap program. FERC appears to be aware of the problem and recognizes the need to maintain a balance between reasonable consumer prices and wholesale prices that are adequate to attract investment in new generation.

Summary Regarding Market Power

The ability and incentive to exercise market power should not increase under SMD as long as two SMD conditions are met: (1) an adequate infrastructure (generation, transmission, and demand-side resources) is maintained at the regional level; and (2) capabilities for effective regional market monitoring and market power mitigation are established and diligently applied. The independent regional market monitor could recommend tougher measures to FERC if needed.

Impacts on Energy Infrastructure Development and Investor Confidence

In its directions to DOE concerning this study, Congress asked for an analysis of the "impacts on energy infrastructure development and investor confidence." In interpreting this language, DOE has focused on how the SMD rulemaking might affect perceptions as to the uncertainties and risks of financing projects that would improve the Nation's electricity infrastructure. Although the SMD rulemaking would have some implications for infrastructure development, after the Commission issued its SMD NOPR it initiated a separate rulemaking, "Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid"

(Docket No. PL03-1-000), to address issues related to whether incentives are needed to ensure transmission-related investment.[1] Further, some of the comments filed in response to SMD suggested that FERC consider regulatory approaches used in other countries to ensure the adequacy of infrastructure investment. Analysis of such alternative regulatory approaches is beyond the scope of this study, particularly given that FERC has opened a separate docket on the subject.

Background

As discussed in DOE's *National Transmission Grid Study*, the creation of wholesale electric markets has enabled market participants to address the need for new generating capacity adequately in most parts of the country. NERC forecasts that generation capacity will increase by almost 20 percent over the next decade, a rate comparable to the expected increase in U.S. demand for electricity. U.S. investment in transmission facilities, however, has been decreasing. From 1975 to 2000, new transmission investment declined at a constant-dollar rate of $117 million per year, and there is growing evidence that the U.S. transmission system is in urgent need of modernization. Shortfalls in transmission investment have led to increased congestion, which has hindered the access of electricity customers to more distant and competitive supply choices. The *National Transmission Grid Study* points to a lack of regional institutions, a lack of clarity in regulatory policy on transmission issues, and problems associated with State-by-State siting approval processes as some of the key barriers to greater investment in transmission facilities.

Since the latter months of 2001, investor confidence in the electricity industry has fallen sharply. According to a recent statement by Merrill Lynch and Co., Inc., for example, the top twenty utilities had a negative cash flow of $10 billion in 2002.[2] Some of the reasons most frequently cited for the flight by investors from the electricity industry are a widespread perception of regulatory uncertainty, the Western electricity disruption of 2000-2001, allegations of improper trading practices, the deteriorating financial health of many electricity suppliers and marketers, and the current oversupply of generation capacity.

According to FERC's NOPR, SMD is intended among other things to help restore investor confidence and encourage investment in transmission and generation infrastructure. The mechanisms proposed are the provisions for locational marginal pricing, a regional transmission planning process, resource adequacy requirements, and greater clarity on transmission investment incentives.

Locational marginal prices that result from the spot markets operated by an RTO would signal to all market participants the value of additional supply and demand response at particular locations. Based on these prices over time, market participants would be able to decide whether additional investment—in transmission or generation facilities or demand response—is warranted. The proposed SMD rule also would provide that those who decide to go forward with infrastructure investments would receive financial rights (CRRs) from the relevant RTO if certain conditions are met:

> If an entity pays to construct new generation or transmission facilities that add transfer capability, and the costs are not rolled in, the entity would receive the Congestion Revenue Rights associated with the new transfer capability.[3]

Because "the price signals alone may not guarantee sufficient investment,"[4] however, FERC also proposes to require a regional transmission planning and expansion process as a backstop for ensuring that needed infrastructure construction is undertaken. FERC calls for the creation of regional State committees to identify the beneficiaries of a proposed expansion and how costs for that expansion should be recovered. Through the proposed rule's transmission pricing policy, FERC seeks to ensure transmission owners the opportunity to recover their revenue requirements and to provide incentives for transmission expansions.

FERC also asserted that a resource adequacy requirement is needed to ensure adequate infrastructure investment:

[1]DOE filed comments in this docket, supporting use of a metrics-based approach to providing incentives for new investment. The approach would be designed to foster highly cost-effective investments, as opposed to capital-intensive investments.

[2]Statement of Steve Fleishman, Managing Director, in FERC Docket No. AD03-000, *In the Matter of Capital Availability for Energy Markets* (January 16, 2003).

[3]NOPR, paragraph 238.

[4]NOPR, paragraph 112.

> Most resources take years to develop and spot market prices alone may not signal the need to begin development of new resources in time to avert a shortage. Moreover, spot market prices that are subject to mitigation measures may not produce an adequate level of infrastructure investment even after a shortage occurs. Further, as long as regional resources are made available to all regional load-serving entities and their customers during a shortage, such entities have the incentive to lower their supply costs by depending on the resource development investments of others, a strategy that leads to systematic under-investment in infrastructure by all load-serving entities in the region.[5]

The resource adequacy requirement would cause electricity retailers to rely to a considerable extent on long-term contracts with suppliers, if they do not already do so. From the supplier's perspective, such contracts establish a stable income stream over time and help potential investors in electricity infrastructure obtain financing.

Reactions to FERC's SMD Proposal

Would FERC's proposed rule work as intended to help restore investor confidence and encourage infrastructure investment? Few commenters on the proposed rule addressed this question directly or provided an unequivocal answer. Some commenters foresee a positive impact from LMP but voice concerns about other potentially negative aspects of SMD. John D. Chandley and William W. Hogan state in their Initial Comments:

> The incentives from locational pricing provide a natural market stimulus to sustain generation and demand-side investments. In addition, the creation and award of financial transmission rights—called Congestion Revenue Rights (CRRs)—provide further opportunities and incentives for market participants to undertake transmission expansion. Participant funding can then become a primary mechanism to support new transmission investments, while license plate rates would be used to recover the revenue requirements of the existing grid. Any needed investments that the market failed to pursue would have their costs assigned to beneficiaries or else rolled into license plate rates . . . .
>
> The Commission must move forward with the core elements of SMD. The electricity system requires an [RTO's] visible but unbiased hand to coordinate the markets and assure reliability. Equally important, the present condition of the industry and the pervasive uncertainty this creates for investors require firm resolve to put the critical institutions in place at the earliest practical date. Moving forward will clarify the industry's emerging structure and make transparent the incentives for investment.[6]

Morgan Stanley Capital Group, Inc., states:

> If LMP signals are allowed to function without interference, they should provide sufficiently strong economic incentives to ensure both short- and long-term reliability. The locational prices will indicate where there is congestion or insufficient generation, and thus will inform the market where new investment is needed. LMP will also provide the price signals necessary to encourage such investment. Implementing market rules for resource adequacy that attempt to replicate LMP outcomes while changing market economics are neither practically nor economically justified.[7]

Chandley and Hogan, echoing Morgan Stanley, found the proposed rule's resource adequacy requirement to be "problematic."[8] Uncertainty regarding the extent to which FERC would require rolled-in versus "participant funding"[9] for new transmission investments was also a source of concern for some commenters. The Western Business Roundtable said:

> WBRT strongly opposes a participant funding approach, which does not spread cost recovery across a broad spectrum of beneficiaries. We believe that such a scheme would actually act as an investment disincentive that will not only halt much needed transmission system upgrades, but also slow new power generation development, whether it be conventional or renewable.[10]

[5]NOPR, paragraph 461.

[6]Initial Comments of John D. Chandley and William W. Hogan on the Standard Market Design NOPR (November 11, 2002), pp. 2-3.

[7]Morgan Stanley Capital Group Inc.'s Supplemental Comments on Standard Market Design Notice of Proposed Rulemaking (January 10, 2003), pp. 7-8.

[8]Initial Comments of John D. Chandley and William W. Hogan on the Standard Market Design NOPR (November 11, 2002), p. 5.

[9]Costs of transmission investments are said to be "rolled in" when they are spread uniformly among all electricity consumers in a given area, in proportion to their consumption. Under "participant funding," costs would be allocated in proportion to the expected distribution of benefits.

[10]WBRT Comments on the Federal Energy Regulatory Commission's Proposed "Standard Market Design" Rulemaking (November 15, 2002), p. 3.

Summary Regarding Investor Confidence and Infrastructure Development

Investor confidence and the level of investment in new infrastructure are affected by many factors, and the impacts of forces outside SMD could outweigh any positive effects associated with SMD. The proposed SMD rule could have a positive effect on investor confidence and infrastructure development in three respects: locational marginal pricing would be likely to give better price signals to investors concerning the location, size, and timing of new facilities; regional transmission expansion plans developed under RTO oversight could boost confidence in the viability of projects that met important regional needs; and regional efforts to establish principles for allocating the costs of new investments could reduce uncertainties that would otherwise undermine investor confidence.

Impacts on Security and Reliability of Generation and Transmission Infrastructure

This section assesses the impacts of the eight major components of SMD[11] on the reliability of the Nation's electric system. Overall, the U.S. electric system is very reliable today and would continue to be reliable under SMD. As summarized in Table 4.1 below, SMD would be unlikely to have adverse effects on reliability and could have several positive effects.

Background on Reliability

Reliability has three important aspects: (1) generation, transmission, and distribution adequacy; (2) transmission security; and (3) the physical and cyber security of the electric system:

- *Generation, transmission and distribution adequacy:* The ability of the electric system to supply the aggregate electric power and energy requirements of customers at all times.
- *Transmission security:* The ability of the electric system to withstand sudden disturbances and remain operational.
- *Physical and cyber security:* The resilience of the electric system against deliberate physical and/or cyber attacks.

The electric system is a critical national infrastructure. Its reliable operation is necessary for efficient delivery of energy and electricity services. A less reliable electric system would add to the cost of electricity for consumers, and reduced reliability could have devastating impacts on public safety and national security. Even small changes, positive or negative, in electric reliability would have significant economic effects.[12]

Because electricity cannot be stored economically in large amounts, the electric system must be able to generate and deliver power instantaneously to customers when and where needed. Also, the system must always have sufficient reserves available to enable its operators to continue serving consumers' needs without interruption when there is an unanticipated failure of a generator or other

Table 4.1. SMD Impacts on Reliability

SMD Provision	Generation, Transmission, and Distribution Adequacy	Transmission Security	Physical and Cyber Security
Independent Grid Operator	No impact	**Improvement**	**Improvement**
Long-Term Bilateral Contract Market	No impact	No impact	No impact
Voluntary Short-Term Spot Market with Transparent Prices	No impact	No impact	No impact
Regional Transmission Planning	**Improvement**	No impact	No impact
Locational Price Signals	**Improvement**	No impact	No impact
Tradable Transmission Rights	No impact	No impact	No impact
Market Power Mitigation	No impact	No impact	No impact
Regional Resource Adequacy Requirements	No impact	No impact	No impact

[11] See pages 2-3 in Chapter 1 for a discussion of the eight components.

[12] See Consortium for Electric Infrastructure to Support a Digital Society, *The Cost of Power Disturbances to Industrial and Digital Economy Companies* (June 2001).

equipment. To ensure the system's reliability, electric system operators must constantly monitor and adjust the system to keep it running within predetermined limits.

The vast majority (over 80 percent) of power outages result from a failure in the electric distribution system. Most are small and localized. Transmission system outages affect broader areas and occasionally spread to large regions of the Nation, as happened in the West in 1996. On rare occasions, power outages occur as a result of inadequate generation and power delivery capacity. This type of outage, frequently referred to as a "rolling blackout," occurs when electric system operators purposely interrupt power delivery to a group of customers in order to reduce demand until it matches available resources. Parts of California and Nevada experienced outages of this type in 2000-2001. Unless there is extensive damage to equipment, as sometimes happens as a result of severe storms, outages are generally short-lived, less than 12 hours in duration. On the other hand, a coordinated physical and/or cyber attack on the electric system could result in damage to critical equipment that could lead to a wide-area outage of longer duration.

The demands on the Nation's transmission and distribution systems have increased substantially while investment in transmission facilities has declined steadily. Electricity demand has grown at an annual rate of 2 to 3 percent while annual investment in transmission has decreased by 50 percent over the past 25 years.[13] Other factors are also contributing to increased stress on transmission and distribution systems. Distribution systems in many older cities are aging and in need of major maintenance or upgrades. While wholesale electricity commerce has led to customer savings of $13 billion annually,[14] the dramatic increase in regional and interregional commerce has also increased stresses on the transmission system. Many are concerned that, without corrective measures, these trends will degrade the reliability of electric service.

Components of SMD With Little or No Impact on Electric System Reliability

For reasons discussed below, five of the eight major SMD components—long-term bilateral contracts, voluntary short-term spot markets, tradable transmission rights, market power mitigation, and regional resource requirements—would have little or no impact on electric reliability.

Long-Term Bilateral Contracts and Voluntary[15] Short-Term Spot Markets

Most load-serving entities today acquire most of their electric power through long-term contracts (if they do not own generation resources) or a combination of long-term contracts and self-generation (if they are part of a traditional vertically integrated utility). Short-term spot markets are used to make adjustments in resources to match changes in near-term load forecasts. This approach to ensuring adequate resources to serve electric loads has proved reliable. The turmoil in California in 2000-2001 demonstrated that reliance on short-term spot markets for most of a utility's resources can contribute to inadequacy of regional generation reserves and electricity shortages. Participants in the California market now rely principally on long-term contracts, and utilities have been able to meet load requirements. However, the balance in a region between long-term contracts and spot market transactions is likely to be determined by factors outside SMD.

Market Power Mitigation

SMD's market power mitigation provisions are designed to address potential horizontal market power problems. If SMD did not include these provisions, there would be greater risk that a generation supplier could induce or contribute to a regional or local electricity supply shortage in an attempt to raise electricity prices, and degrade reliability in the process. To the extent that these provisions in SMD are successful in limiting the exercise of market power, there would be little or no net effect on reliability.

[13]From data provided by E. Hirst and B. Kirby, *Transmission Planning for a Restructured U.S. Electric Industry,* Edison Electric Institute (2001).

[14]U.S. Department of Energy, *National Transmission Grid Study* (May 2001).

[15]Participation by buyers and sellers in short-term markets would be voluntary, but establishment and operation of such markets by RTOs would be mandatory.

Tradable Transmission Rights

Tradable transmission rights—or CRRs—are financial rights that provide those who currently own physical rights to the use of transmission facilities or who invest in new transmission facilities across transmission bottlenecks a means of securing the value of that ownership. Some parties have suggested that holders of CRRs may have an incentive to avoid building new transmission facilities that would improve transfer capabilities. However, apart from a small amount of merchant transmission capacity, transmission facilities will still be subject to cost-of-service regulation under SMD. For non-merchant transmission capacity, this means that revenue from CRRs would be credited against the revenue requirement previously established for a transmission facility. Thus, even if the market value of CRRs for transmission in a particular area were to go up sharply, that would not create an incentive for a transmission owner who held such CRRs to avoid new investment that would ease congestion in the area, and reliability would not be affected.

Regional Resource Adequacy Requirements

The proposal in SMD for minimum reserves would be likely to aid the creation of capacity markets and enable development of facilities or programs needed to meet peak loads. In a regulated environment, the costs of peaking facilities are recovered by inclusion in a utility's rate base. In a competitive environment, peaking facilities (or non-generation alternatives) that are needed to ensure reliability might not be economically feasible if based only on payments for a few hours of operation per year. In either case, there would be no impact on reliability as long as the reserve requirements were met. As discussed below, enhanced demand response may enable compliance with resource adequacy requirements at significant savings to consumers (see "Potential Benefits of Enhanced Demand Response," page 61).

Components of SMD Resulting in Improvements to Electric System Reliability

The remaining three major components of SMD would be likely to improve reliability, as explained below.

Independent (Regional) Grid Operators

Independent (regional) grid operators would improve transmission and physical and cyber security by:

- Providing system operators with visibility over a larger portion of the transmission system so that operators can better understand the nature of a system disturbance and respond more quickly and effectively;
- Giving operators control over more resources in order to coordinate a more efficient response to a disturbance;
- Allowing operators to see patterns of failure that may be indicative of a coordinated attack on the electric system; and
- Providing operators the ability to better coordinate operations with transmission maintenance activities.

The cascading power outage in the West on August 10, 1996, provides a good example of how an independent regional grid operator might have helped control the spread of a disturbance. This outage began with a series of transmission line failures in the vicinity of Portland, Oregon, over the course of several hours and eventually expanded to interrupt electric service to 7.5 million customers throughout the western grid. A key factor contributing to the spread of the outage beyond the Bonneville Power Administration's electric system was that controllers of adjacent electric systems were not aware of the problems being experienced by Bonneville and therefore were not able to configure their systems to inhibit the spread of the outage.[16]

One aspect of regional-scale transmission operations is that it enables the system operators to increase the load on the system while staying within the industry's reliability limits. To be prepared for unforeseeable system conditions, operators incorporate reserves into real-time operating limits. Under SMD, operators' regional perspective would give them increased knowledge of actual grid conditions and enable them to reduce safely the level of reserves required. While this would lead to increased loading of the transmission system, it would not result in degradation of transmission security as long as the system is operated within the reliability limits.

[16]Western Systems Coordinating Council, *Disturbance Report for the Power System Outage That Occurred on the Western Interconnection* (October 18, 1996).

Regional Transmission Planning

A regional approach to transmission planning and related planning issues would improve the adequacy of generation, transmission and distribution by:

- Providing a coordinated regional approach to planning for the solution of adequacy problems;
- Providing planners with a greater number of options, including out-of-local-area actions, to solve local adequacy issues;
- Improving coordination among State and regional resource agencies, which should result in an increase in investments to relieve transmission bottlenecks; and
- Providing planners with improved access to non-transmission resource alternatives—such as strategically located energy efficiency, demand response, and distributed generation resources[17]—to remove transmission bottlenecks and stress on distribution grids.

Locational Marginal Pricing (LMP)

LMP is likely to lead to improvements in generation, transmission and distribution adequacy by:

- Encouraging improved generator availability and efficiency,[18] which should improve adequacy in the short term;
- Providing economic signals over the long term to generators to locate new energy resources on the load side of bottlenecks, thereby freeing up transmission resources; and
- Providing signals to potential developers of new transmission capacity (or functional substitutes) concerning the location, duration, and severity of transmission congestion.

The LMP component of SMD should not adversely affect system security. In the parts of the Eastern Interconnection not managed by RTOs, system operators avoid real-time transmission conditions that would exceed reliability limits and threaten system security through transmission line loading relief (TLR) procedures. Using TLR, operators curtail scheduled transactions that could lead to transmission line overloads. Under SMD, these procedures would be replaced by LMP, which would both maintain reliability and limit congestion in a manner that is more efficient economically than TLR. It is important to note that the level of congestion in the transmission system does not affect system security as long as the system is operated within reliability limits.

Impacts on State Regulation of Electric Utilities

In its proposed SMD regulation, FERC states that it does not intend "to interfere with the legitimate concerns of state regulatory authorities," and that it seeks "to formally involve state representatives in the decision-making processes of regional entities."[19] The Commission also explicitly recognizes "the need to permit parties to continue to rely on existing contracts and scheduling practices, including those involving hydroelectric power, and these are fully accommodated under Standard Market Design."[20]

The SMD proposal would nevertheless have a variety of impacts on States and State regulation of electric utilities. Six of SMD's major components would have some impact on State regulation. They are: an independent grid operator, market power mitigation, regional resource adequacy requirements, regional planning, locational price signals, and tradable transmission rights.

Independent Grid Operator and Service to Retail Customers

FERC says in the proposed SMD rule that to remedy existing opportunities for undue discrimination in favor of generation owned by a transmission owner or an affiliate of such owner,

> . . . we propose to place all transmission customers under the same set of rules. We propose to place transmission service for bundled retail customers under the same terms and conditions of service as wholesale transmission service. To accomplish this we propose to revise the existing *pro forma* tariff to remove provisions that grant preferential treatment to transmission service for bundled retail customers . . . . We also propose that . . . only Independent Transmission Providers would

[17]"Distributed generation" refers to small generation and energy storage facilities located near end-use customers. When in operation, such facilities can reduce the immediate area's demand for electricity from conventional generation facilities and the need for transmission services.

[18]See page 7 and footnote 6 in Chapter 2.

[19]NOPR, paragraph 16.

[20]NOPR, paragraph 16.

> operate Commission-jurisdictional facilities. This requirement will apply whether or not the public utility that owns, controls or operates interstate transmission facilities has joined an RTO.[21]

Note that FERC refers above to the "*terms and conditions*" of service, but not to *transmission rates*. FERC sought comment on whether the Commission should allow different rates for wholesale and bundled retail customers:

> [T]he question arises as to whether different charges for transmission service for wholesale and bundled retail customers should be permitted. Allowing different rates for wholesale and bundled retail customers could lead to undue discrimination if the rate setting policies of the state and the Commission differ significantly. The Commission seeks comment on whether all customers should be charged the same transmission rate either upon implementation of Standard Market Design or after a reasonable transition period of four years.[22]

Recent public statements by Chairman Wood indicate that the Commission now intends to allow wholesale transmission rates and the transmission portion of bundled retail rates to differ.[23] The NOPR explains a procedure FERC has used in this regard:

> When a vertically integrated utility joins a regional organization such as an ISO or RTO, the Commission has required that the utility execute a service agreement under the regional transmission provider's transmission tariff. For instance, the Commission required the vertically integrated utilities in GridSouth to execute a service agreement under the GridSouth transmission tariff, thus ensuring that these utilities would take service for their bundled retail load under the same terms and conditions as all other users of the grid.
>
> With respect to whether the GridSouth transmission charge should be applied to the bundled retail load, the Commission permitted the utilities to pay the transmission portion of the bundled retail rate, but required that the service agreement explicitly state the rate to be charged. The Commission added that having vertically integrated utilities pay GridSouth for transmission to serve their bundled retail customers does not make those utilities' retail rates subject to our jurisdiction. Rather, the Commission stated its willingness to accommodate the utilities paying GridSouth a transmission rate equal to the transmission component of their bundled retail rates, as long as the price is clearly stated, reduced to writing in contracts with GridSouth, and is not accomplished by omission.[24]

Requiring an independent transmission provider and requiring that transmission service for retail customers be provided under the same non-price terms and conditions as for wholesale customers would not eliminate the ability of regulators in States without retail choice programs to provide preferential treatment to "native load."[25] State regulators could continue to direct that certain generation and transmission facilities be used for the benefit of native load before other customers are served.

Market Power Mitigation, Regional Resource Adequacy Requirements, and Regional Transmission Planning

Although the proposed SMD rule projects a role for RTOs in areas formerly exclusive to the States, the rule also proposes to "establish a formal role for state representatives to participate on an ongoing basis in the decision-making process of these organizations."[26] FERC proposed that each RTO would have a Regional State Advisory Committee (RSAC) designed to provide the RTO, market participants, and FERC with a consensus view from States in the geographical footprint of the RTO.

Market Power Mitigation

Many States are working with an existing ISO or RTO that either has or will have a market monitoring function. Most States are strongly in favor of requiring market mitigation and monitoring. The disagreements or suggestions from States are with the particulars of FERC's proposed monitoring and mitigation plan as outlined in the NOPR.

In the SMD NOPR, FERC proposes that the market monitor would report directly to FERC and the independent governing board of the RTO. FERC also indicates that the market monitor would be accountable only to the Commission and the governing board, but that it would share its analyses

[21]NOPR, paragraph 109. Note that a FERC-approved RTO would qualify as an Independent Transmission Provider.
[22]NOPR, paragraph 178.
[23]Remarks to National Commission on Energy Policy (April 1, 2003).
[24]NOPR, paragraphs 176-177.
[25]"Native load" customers are a vertically integrated utility's retail customers.
[26]NOPR, paragraph 551.

and reports with the management of the RTO and the RSAC. States have noted that being accountable and having an advisory role are not the same, and have proposed a more significant State role in the monitoring and mitigation process. This would include a more expanded role in the selection and review of the market monitor, access to the monitor's reports and communications with FERC and the RTO management, and access to data.

Many States with retail access have assigned staff or created staff subdivisions with monitoring responsibilities. The staff's primary functions may include collecting data on retail market activity, preparing reports and presentation for internal commission use and for public information, tracking wholesale market activity, and analyzing market developments and how they may affect their State or region. Some States have expressed an interest in having the State commission's monitoring unit be allowed to coordinate with the RTOs or the RTOs' monitoring and mitigation units. Some have also suggested that the RTO monitoring units should coordinate with each other as well.

An important issue for States is that they, in addition to FERC and the market monitors, have access to market data collected and the analyses the market monitors conduct. This has raised the issue of the proprietary nature of some of the data and market participants' concern with disclosure of information of potential use to competitors or potential competitors. In a regulated environment, access to data was a less sensitive subject, because the parties were not in direct competition and much of the information collected by Federal and State agencies was made public. States have argued that information can be shared with FERC and others in a manner that will protect sensitive data by means of nondisclosure agreements and the release of time-sensitive information after a reasonable amount of time.

FERC has proposed that the market monitoring unit would be autonomous of the RTO's management and market participants, and would report directly to FERC and the independent governing board of the RTO. This has raised the issue of the independence of the market monitor from the RTO and market participants. Since the monitor reports to and is funded by the RTO, the RTO could have some control over the type of analyses conducted and, perhaps, the results. Some States have suggested that the monitoring units should be accountable only to FERC (and some would add the States as well), and not to the RTO governing boards, in order to maintain their independence and impartiality. Some States have also suggested that there be some kind of review process of the monitoring unit's work for quality assurance and as a means to develop "best practices" among the monitors.

Regional Resource Adequacy Requirements

FERC's proposed SMD rule includes procedures to ensure, on a long-term regional basis, the adequacy of generation and demand-side resources. FERC proposes that an RTO "must forecast the future demand for its area, facilitate determination of an adequate level of future regional resources by a Regional State Advisory Committee, and assign each load-serving entity in its area a share of the needed future resources based on the ratio of its load to the regional level."[27] The proposed rule states that this requirement is designed to complement rather than replace existing State resource adequacy programs:

> A vertically integrated utility satisfying a current state resource requirement that equals or exceeds its share of the resource adequacy requirement would not have to do anything more. For those states that have retail choice programs in which retail customers or their suppliers buy power from a multi-state region, we intend this approach to provide for regional adequacy in a way that no one state alone may be able to accomplish.[28]
>
> The proposed approach is like the traditional reserve margin requirement imposed by states on monopoly utilities. It worked well during most of the last century to ensure adequate supplies, and is still in use in most states, especially states that have no retail choice program. However, because the traditional approach relies on individual utility plans and resources, it might not continue to work well in a region where utilities now rely on independent power producers in several states for new resources instead of their own new generation. The traditional reserve margin requirement may also not work well in a region where some states have traditional monopoly utilities and others have retail choice because a shortage in one state can affect all states in the region.
>
> To continue to rely on the traditional reserve margin requirement, it has to be adapted to have a

[27]NOPR, paragraph 474.
[28]NOPR, paragraph 480.

regional focus and to fit with competitive procurement. We propose a resource adequacy requirement of this type.[29]

Some States are concerned that FERC's proposed regional resource adequacy requirements expand the Commission's role into an area formally of State domain. This concern is raised because FERC's proposal involves generation capacity, which is now the States' responsibility, and some States fear that the inclusion of such requirements in the proposed rule would constitute a step toward eventual FERC jurisdiction over aspects of generation other than approval of prices for the sale of wholesale electricity. Moreover, some States fear that even if current FERC commissioners do show deference to States on resource adequacy issues, a future FERC might, once authority is established, bypass the States and expand further into generation issues.

SMD's proposed resource adequacy requirement would help to ensure that regional infrastructure keeps pace with growth in demand. However, the States could accomplish this without SMD through regional coordination.

Regional Transmission Planning

Under FERC's proposed SMD rule, RTOs would be responsible for coordinating the development of regional transmission expansion plans, and they would be required to work with the States and other interested parties in developing such plans. However, transmission planning inevitably becomes involved with a number of related planning issues, including resource adequacy, generation siting, demand response, and other alternatives to enhancing conventional transmission capacity. FERC has generally shown great interest in working cooperatively with the States and existing regional bodies to ensure that this cluster of issues is addressed successfully at the regional level.

Some States have suggested that regional planning for resource adequacy and perhaps other regional electricity planning issues could be addressed through multi-State entities (MSEs) that would operate under the authorities of the participating States.[30] Many States have also expressed a preference for working with an RTO through a regional body that has legal standing and authority, as opposed to the advisory role proposed by FERC under the RSAC concept.

Although FERC did not assert jurisdictional authority in the SMD NOPR over siting of transmission facilities, most States are nevertheless concerned about the possibility that they might lose siting jurisdiction in the future. Many who believe that States should retain this authority recognize the merits of making transmission siting decisions from a regional perspective, but they would prefer that it be done through a State-controlled body, such as an MSE, as opposed to a Federal agency.

The need to improve regional coordination among States on electricity matters has been discussed for more than 20 years, but there still is no formal structure in Federal or State law to guide regional interaction, planning, or coordination for the electricity industry. Development of a formal structure would raise concern over a possible "third layer" of regulation, and the development of effective regional bodies would presumably require supportive Federal and State legislation. For the near term the MSE concept may prosper, because it does not intrude upon existing State or Federal authorities, and it affords the possibility of resolving some regional electricity policy questions on the basis of consensus achieved through better communication and coordination.

Establishing or Enhancing Demand Response Programs

Enhanced demand response capability is not cited as one of the eight major components of SMD, but it is a topic of concern to both FERC and the States with respect to market power mitigation, regional resource requirements, and regional transmission planning.

[29]NOPR, paragraphs 480-82.

[30]The National Governors Association's *Interstate Strategies for Interstate Transmission Planning and Expansion* (July 2002) recommends that states form (or use existing) multi-state entities (MSEs) "to improve interstate coordination on transmission planning and expansion. The MSE is intended to: (1) establish a framework for state input into RTO planning; (2) facilitate a "one-stop" application process that consolidates relevant regulatory activities of affected states, including a "Regional Need Finding"; and (3) provide a forum in which states, federal (land management) agencies, and, where relevant, tribal authorities and border countries (Canada and Mexico), can resolve siting disputes and otherwise address issues relating to transmission expansion." According to this report: "The formation of MSEs should follow the footprints of regional electricity markets. In some regions, states may choose to use or develop a regional coordinating body that corresponds to an area that is larger than a single RTO. For example, in the West, states are coordinating an interconnection-wide basis that encompasses more than one (proposed) RTO. In other regions, states may elect to form MSEs at a sub-RTO level."

While many States agree that enhanced demand response programs are needed to improve market efficiency and limit market power, there is concern that doing so under FERC or RTO auspices will intrude on State jurisdiction, because of the likelihood that retail rates would be affected. For example, most States already have time-of-use tariffs for different customer classes, and any move toward real-time pricing of electricity would affect retail prices. For States with retail access, even though they may no longer determine a retail price for power, they usually still determine a "price-to-compare" or standard offer rate for non-choosing customers. Also, all participating customers, whether on standard offer service, regulated price, or receiving a competitive price, would have other needs that would have to be addressed, such as provision of time-of-use meters and technical support.

Many potential industrial and commercial participants in demand response programs operate in several States across a region, and have indicated that regional consistency among States in the design of demand response programs is needed to facilitate customer participation.

Locational Marginal Pricing

As discussed in preceding sections, LMP is an essential element of SMD, in that it would be the mechanism for efficiently managing the use of scarce transmission resources. Tradable transmission rights (CRRs) are complementary to LMP, because they provide a means by which market participants can protect themselves against the volatility of the transmission congestion costs that LMP makes visible. Both LMP and CRRs have implications for State utility regulation.

Turning first to LMP, the States that have embraced retail competition find that LMP provides an accounting framework and disaggregated prices that ease and simplify the integration of wholesale and retail markets. By comparison, some of those opposing SMD have objected to LMP in two respects, as follows.

Applicability of LMP to Systems That Rely Heavily on Hydro Resources

In the Northwest, hydro resources are a large and important component of the region's generating capacity. The water that drives hydro generation must also be managed to serve a variety of other important public policy purposes, including habitat maintenance for fish and wildlife, recreation, and irrigation. Thus, other policy purposes impose constraints on the day-to-day operation of the hydro system as an electricity source. In addition, although the hydro units have very low operating costs, their seasonal output is limited by the amount of water stored in upstream reservoirs. Therefore, other factors permitting, the managers of the hydro system seek to run the hydro units when demand and regional wholesale prices are relatively high, so as to use the finite amount of producible electricity to displace generation from higher-cost sources. This reduces the region's total generation costs, and consumers' electric bills.

Northwest States and Northwest generators, such as the Bonneville Power Administration (BPA), have expressed the concern that LMP might conflict with Northwest resource uses, practices, and obligations. The difficulty with LMP in the hydro context is that LMP itself does not provide a satisfactory basis for the dispatch of hydro resources. LMP and regional economic dispatch normally operate on the basis of generating units' respective marginal costs. If this were used for hydro, the hydro units would be dispatched very early in the dispatch order, and the aggregate value of the hydro output would be diminished. A possible solution is to allow the hydro operator to "self-schedule" hydro generation; that is, the hydro operator could be allowed to bid hydro units into the market with little notice, and at costs low enough to ensure that the units would always be selected to run by the RTO's unit-commitment algorithms. This would give the hydro operator the latitude needed to maximize the aggregate value of the hydro output in seasonal terms.

Such an approach would have to be augmented, however, by an arrangement to ensure that the hydro operator was not exercising market power—for example, by withholding generation from the market to induce higher market-clearing prices. (Note that imposing "must run" requirements on hydro units would tend to conflict with the need to provide operational flexibility to the managers of the hydro system.) A potential solution is to devise "safe harbor" requirements—a set of operating guidelines for the hydro operator that, if adhered to, would confirm that the operator was following agreed-upon principles and not exercising market power.[31]

FERC's proposed rule concludes that Northwest concerns about LMP can be accommodated within SMD, and FERC has taken steps since issuance of the proposed rule to help ensure such accommodation. For example, FERC approved the formation of RTO West, which BPA has characterized as "the vehicle that has the best chance of achieving the Commission's primary goals of achieving lowest-cost service, building sufficient infrastructure, establishing clear market rules, protecting against market manipulation, and establishing clear pricing and planning for grid expansions, while also meeting the unique needs of the Northwest region."[32]

LMP and "Load Pockets"

A "load pocket" is a load area that has limited transmission access; this makes the load pocket relatively dependent on local generation sources, and may raise market power issues. The problem may be compounded by an inadequacy of generating capacity within the load pocket, as in the city of New York and some other major cities. The market power issues can presumably be dealt with through price caps on local "reliability/must run" (RMR) units, or other measures if necessary. Nonetheless, LMP tends to raise wholesale electricity prices for load pockets (and reduce prices elsewhere), because load pockets are in fact subject to transmission congestion, and LMP is expressly designed to cause areas whose demand creates congestion to pay the incremental costs that would otherwise be borne by other parties in the wholesale market.

Some State opponents of SMD contend that LMP's price signals are not needed, because the need for actions to ease load pockets—such as new generation inside the pockets, improved transmission capacity, or other possible solutions—usually is well known, and that LMP will simply create higher prices for consumers in those areas with no direct benefit.

Proponents have several responses:

- LMP creates a fairer distribution of transmission congestion costs by focusing the costs on those whose demand creates the congestion.
- LMP opponents are essentially denying elementary economic theory—that higher prices will make appropriate solutions (including distributed generation and other demand-response options) economic and send appropriate signals to both developers and consumers.
- In the long term, LMP will help to reduce costs in load pockets by spurring the development of new resources in the areas where they are most needed.
- An RTO would be well-positioned to facilitate economically appropriate responses by serving as a clearinghouse for credible information that regulators and market participants will need about risks, cost and revenue streams, etc., before private parties will make investments to alleviate the underlying problems.

Tradable Transmission Rights

Under SMD, transmission customers would be able to obtain tradable long-term rights to the transmission grid—that is, CRRs. FERC proposes that all firm transmission service would be converted from the current system of physical transmission rights to CRRs, including the firm transmission service currently reserved by a transmission owner (TO) for its retail native load customers and grandfathered transmission contracts that pre-date Order No.888.[33] This would bring all transmission service, including both transmission

[31] See R. Rajaraman and F. Alvarado, "Testing for Market Power in Hydro-Dominant Regions," VIII SEPOPE (Brasilia, June 2002); and R. Orans, A. Olson, and C. Opatrny, "Market Power Mitigation and Energy-Limited Resources," *The Electricity Journal* (March 2003). According to FERC, "Some parties in the Northwest acknowledge that a bid-based LMP system could be adapted to meet the objections above but are concerned either that such a system may be imposed without adaptation or that the adaptation will be done poorly. There is also concern that adaptation to a bid-based security-constrained system may reopen such issues as transmission priorities and preference power allocations that have been settled over many years of negotiation based on factors other than market efficiency. Finally, Northwest parties worry about obtaining sufficient Congestion Revenue Rights to protect against congestion charges." (NOPR, paragraph 214.)

[32] Comments of the Bonneville Power Administration (February 28, 2003), p. 3.

[33] Note that transmission customers would have the option of converting pre-Order 888 contracts to the new transmission service and thereby receiving CRRs, for example. However, if the customer chose not to exercise this option, the contract would nonetheless effectively be converted. In such circumstances, the transmission owner would provide the grandfathered service to the customer, but take the converted service from the RTO. The conversion risk would be accepted by a customer exercising its option, but placed on the transmission owner if the customer decided to not exercise the option. Thus, all firm service would be converted, with the associated risk assigned to one party or another.

service in support of retail load and transmission service in support of wholesale transactions, under the auspices of the RTO.

All transmission customers would be treated on the same basis—one of FERC's principal purposes in proposing this change. Broadly speaking, it would reduce the potential for discrimination in the use of the grid, while promoting its economically efficient use. Understandably, the prospect of this conversion creates certain concerns. Issues that need to be addressed include the two discussed below.

Allocation of CRRs

FERC has indicated that native load and those who have existing contracts for transmission service will be able to receive sufficient CRRs to cover current needs, and that it intends to work with the States to ensure that allocation issues are resolved satisfactorily. Parties who have paid for the construction of transmission capacity that they are not using now and that has not been committed to others via long-term contracts would acquire the CRRs to such capacity and would be able to rely on it to meet future demand growth. In recent statements, FERC has indicated a willingness to cooperate with States and others on CRR allocation issues to ensure that all who have existing rights to the use of transmission facilities do not lose such rights in the transition to a CRR regime.

Conversion Issues

The process of converting existing wholesale transmission service to the new transmission service would be complex.[34] Old contracts may not have the same system of financial charges that would be used for the new service. Differences may include average losses versus marginal losses, flat fees versus volumetric fees, options rights versus obligations, outage risk placed on one party versus the other, and so on. These can be important financial matters, and they would have to be addressed separately for different contracts and customers.

Moreover, some pre-existing contracts may have unique fact patterns that may be difficult to convert into the terms and conditions for the new service. For example, there is a substantial difference of opinion as to how to convert the "Farragut Wheel" arrangement into CRRs. The Farragut Wheel is an arrangement through which transmission service is provided by PSE&G (in PJM) to Consolidated Edison (in the New York ISO) to move power from a point in New York north of New York City, through the PSE&G service territory in New Jersey, and back into New York City. The service is supported by phase angle regulators (PARs)[35] at both ends of the Wheel. The contractual rules for operating the PARs in conjunction with other power flows between the two ISOs are not easily reconciled with the new transmission service envisioned by FERC. In this example, two neighboring independent transmission providers (NYISO and PJM) have not been able to resolve matters, and the issue has been presented to the Commission for resolution.

Another example of conversion difficulties involved the Old Dominion Electric Cooperative (ODEC) and its conversion as part of PJM to an FTR[36] regime for transmission on the Delmarva Peninsula (east of the Chesapeake Bay). The Delmarva Peninsula has limited import capability and relatively high-cost generation, and transmission congestion is a common occurrence. ODEC owns no generation to serve its 400 MW of load on the peninsula, but instead has been a requirements customer of other utilities. ODEC made a business decision to pursue lower-cost purchasing opportunities outside the peninsula, for delivery using the limited transmission import capacity.

Initially, PJM monitored the peninsula's transmission system down to the 115 kV level. At that level only minor amounts of congestion occurred, and so ODEC decided to forgo requesting FTRs from PJM. Later, PJM changed its transmission monitoring and LMP pricing to include the peninsula's 69 kV lines, which more accurately portrayed the higher levels of congestion occurring on the peninsula. However, ODEC was unable to request FTRs at the time the change was instituted. As a result, ODEC was importing substantial amounts of power from the PJM Western, hub unhedged by FTRs, and suffered substantial financial losses for a period of time. The situation has since been alleviated by an out-of-sequence allocation of FTRs to

[34] Not all of these problems would fall under State jurisdiction. However, State officials understandably take a keen interest in matters that they believe could adversely affect communities in their State.

[35] A "phase angle regulator" is a high-voltage, transformer-like device that enables transmission system operators to exercise increased control over the amount of electricity that flows over a particular line or group of lines.

[36] "FTR" is PJM's equivalent of FERC's "CRR," which stands for "congestion revenue right."

ODEC by PJM, combined with other moderating measures.

Thus far, the Farragut Wheel and the ODEC experiences appear to be unusual, but they are nonetheless real-world examples of transitional problems that may arise in the process of converting from one system of transmission service to another on a regional scale.

Potential Benefits of Enhanced Demand Response

Introduction

Inclusion of a separate section on demand response (DR) in this report merits explanation. Although FERC Chairman Wood did not cite DR formally as a major component of SMD in his speech of February 13, 2003,[37] he addressed it in his discussion. DR was also examined at length in FERC's SMD NOPR, and many who support broader competition in wholesale electricity markets also support enhanced DR, both as an effective means of making consumers less vulnerable to the exercise of market power and as a source of other benefits to consumers. The discussion that follows is intended to demonstrate that the potential benefits of enhanced DR are large, and that such benefits are unlikely to be achieved without some key features associated with—but not dependent on—SMD, such as RTOs and LMP. However, although RTOs and LMP appear important to the achievement of these benefits, they would not be sufficient to ensure their achievement, which would also require continuing policy support from FERC, RTOs, and State regulators.

A market achieves maximum efficiency when the price for a product reflects both the cost to supply it and the product's value to a consumer. Wholesale electricity markets will not achieve that end as long as most retail customers are insulated from the occasional price volatility that characterizes wholesale supply.

Estimating the benefits of demand response (DR) programs associated with SMD is subject to many uncertainties. Detailed assumptions must be made about the nature of the underlying supply and demand conditions for centralized short-term wholesale markets that in some cases have not yet been created. Experience with DR programs in ISOs in the Northeast provides a credible starting point for measuring the impacts of DR on prices and reliability throughout the United States, and supplies credible values for the key assumptions used. Extrapolating these values for all regions provides a reasonable portrayal in the aggregate, but the specific regional implications may not be representative of existing conditions. The results should be understood as indicating the value of DR only under the postulated conditions.

Two basic types of DR programs are discussed here:

- *Curtailments bid into a day-ahead market*, which are projected below to provide potential direct benefits in the hundreds of millions of dollars per year range. These benefits would vary in size and regional distribution from year to year according to prevailing supply and weather conditions. Additional benefits, which are hard to quantify because they represent avoided consequences, would come in the form of lower and less volatile bilateral contract prices and increased market integrity and efficiency.
- *RTO dispatch of curtailments to alleviate reserve shortfalls*, which is projected to produce benefits in increased reliability in the range of $100 million to $400 million annually. These benefits will be highly variable across the country, but almost every control area has occasion to benefit from such resources during a few hours each year. In areas where reserves are tight, especially in transmission-constrained load pockets, RTO dispatch of curtailments can make the difference between the inconvenience of a voltage reduction and widespread outages.

DR is an important ingredient for the efficient operation of wholesale electricity markets. However, the realignment that accompanies the formation of ISOs and RTOs undermines traditional load management programs, and the risks and complexities of these markets act as barriers to the development of new, compatible DR products and services by retailers. Inclusion of DR as part of SMD implementation would provide low-risk, high-benefit opportunities for customers to contribute to the efficient operation of wholesale electricity markets and pave the way for more diversity in retail markets.

[37] Address by FERC Chairman Pat Wood III to CERA conference, Houston, TX, February 13, 2003. See especially pp. 2, 5, and 7. The speech is on FERC's web site at http://www.ferc.gov/news/speeches/commissionersstaff/CERA_Keynote_Feb_131.pdf.

SMD and other FERC initiatives pertaining to wholesale electricity markets have been founded on the premise that removing barriers to electricity commerce benefits consumers. Most of these efforts have focused on reorganizing the wholesale arrangements by which electricity is supplied. However, it has become evident that facilitating price-responsive behavior by at least some consumers can be strategically valuable as a means of disciplining wholesale markets. Short-term DR is a temporary reduction in electricity consumption by end-use customers, either in response to market prices for electricity or in response to inducements offered by other parties, based on the value of such reductions in consumption.[38]

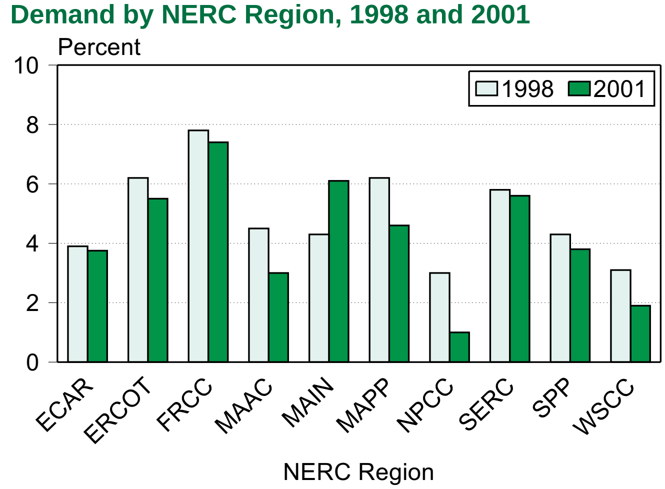
DR can significantly influence the consumption behavior of retail customers in both the near term and the long term, regardless of how the retail markets served by the RTO are organized. That is, the potential benefits under discussion here are achievable with or without retail competition. What is critical is the role of the RTO: DR can be used to mitigate regional market exigencies, but only the RTO will be able to foresee and mitigate them by scheduling and dispatching the appropriate amount of DR.

Demand Response and Market Design

Vertically integrated utilities have sponsored DR programs, referred to as load management programs, for decades. They and their regulators recognized that reliability is a public good; customers cannot be expected to self-provide reliability by curtailing usage during times of reserve shortfalls.[39] A practical solution was to recruit some customers who were willing and able to curtail their electricity use in return for compensation to cover their costs, thereby establishing load as a system resource. An additional benefit of such arrangements was that they provided flexibility that helped assuage rate shocks[40] associated with indivisibility of conventional supply investments. Some utilities took the next step and offered customers opportunities to buy electricity at the marginal cost of supply through real-time pricing (RTP) programs. In the late 1990s participation in load curtailment programs in the United States amounted to almost 3 percent of peak demand, and more than 2,000 commercial and industrial customers were enrolled in RTP programs.[41]

The reorganization of regional wholesale markets threatens to undermine or even eliminate these load curtailment programs. DR as a percentage of total demand has been declining since 1998 (Figure 4.1). Legacy DR programs relied on the notion of avoided cost to justify the recovery of payments for curtailment rights through the rate base. The unbundling of industry functions makes it difficult for any of the successor entities—regulated and unregulated retailers, wires companies, and generation firms—to justify the cost on their own. In an unbundled setting, only the RTO has the universal market perspective required to ensure that curtailable DR resources are dispatched when they are needed, in the

Figure 4.1. Demand Response as Percent of Total Demand by NERC Region, 1998 and 2001



[38]Other types of DR programs may include time-sensitive pricing products that are designed to induce long-term changes in consumption behavior.

[39]Boisvert and Neenan provide an exposition of this concept and demonstrate the public nature of reliability in a forthcoming report. R.N. Boisvert and B.F. Neenan, *Establishing the Social Welfare Implications of Price Responsive Load in Competitive Electricity Markets*. Prepared for Lawrence Berkeley National Laboratory (2003).

[40]"Rate shock" refers to the consequences of the indivisibility ("lumpiness") of generation units on regulated rates. As demand grows over time toward the level of available capacity, rates are typically stable, or may actually go down, as fixed costs are spread over an ever larger usage base. However, when demand growth starts to compromise reliability, new capacity is added in a "lump" and rates are raised to cover its costs, sometimes leaving customers perplexed and shocked by the result.

[41]Peak Load Management Alliance, *Demand Response: Design Principles for Creating Greater Customer Value* (October 2001); and estimates derived from FERC reporting forms and information collected by Neenan Associates from program administrators.

amount needed.[42] Moreover, the RTO is in a unique position to offer customers the opportunity to bid curtailments that compete against supply in a manner that ensures that the total cost of supply is minimized and system reliability is not compromised. Thus, unless balanced by actions by the RTO, industry restructuring is a deterrent to continuance or expansion of the role and value of load management assets.

The RTO's generic role as the facilitator of the wholesale markets in its footprint (i.e., the near real-time market, the day-ahead market, and the markets for ancillary services) can be extended to facilitating consumer participation in wholesale markets without interfering in the organization and operation of retail markets. Actual recruitment of participants can be the responsibility of the retail entities that have relationships with consumers. Similarly, RTO-sponsored programs do not preclude the operation of private demand trading centers.[43] Such entities can help facilitate the matching of diverse customer load management capabilities with the requirements of the RTO, which are of necessity stringent.

Integrating Demand Response into Wholesale Market Operations

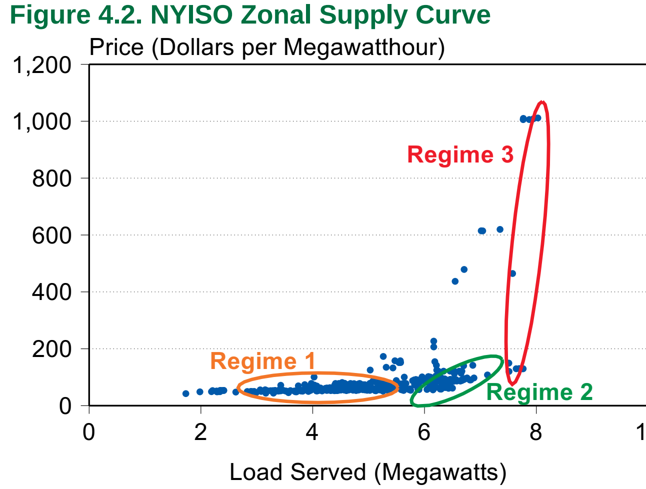
SMD is designed to facilitate increased electricity commerce among wholesale buyers and sellers, over larger areas. Spot markets managed by RTOs provide transparency and liquidity to energy and reliability markets and enable buyers and sellers to assess more accurately the value of bilateral contract opportunities. Transparent spot markets also expose a condition that is inherent to regional electrical systems but has not been readily apparent to the public: at times, wholesale prices rise to very high levels to clear the market. Private transactions in excess of $7,000/MWh were reported in 1999. Prices in the PJM and NYISO markets occasionally approach the existing $1,000/MWh price cap imposed by FERC. The caps do not eliminate the situation, although they limit its impact on consumers. DR resources offer a means to accomplish that end more effectively and with lower consequences for decisions about investment in new generating capacity.

The conditions that cause prices to spike are generally associated with very high loads, capacity shortfalls, or both. As shown in Figure 4.2, a typical regional electricity supply curve has a long flat section as loads build up, but then its slope increases rapidly as load approaches its highest level—a shape that calls to mind a hockey stick. The data points in Figure 4.2 are hourly market price and quantity pairings from NYISO real-time market data. The figure suggests that the supply relationship has three different regimes or segments, the last of which has a very high slope. When electricity supplies are very short, prices rise very sharply to supply even small increments of additional demand.

Implicit in Figure 4.2 is a potential remedy for such price spikes. If a relatively small number of consumers would be willing to reduce their usage during these times, the impact would be significant. The market-clearing price would fall to more normal levels, reducing the cost of supply for all parties buying at that time. Further, abating severe price spikes systematically could reduce the cost of hedging bilateral contracts, enabling all customers to benefit from the action of a few.

How can a sufficient number of consumers be enticed to curtail at exactly the right times? What are the potential benefits for consumers in the aggregate? The following sections describe opportunities for integrating DR into RTO operations and provide an initial estimate of potential annual

Figure 4.2. NYISO Zonal Supply Curve



[42]Other factors have contributed to the reduction in load curtailment programs. Investments in demand-side management were viewed in some jurisdictions as a substitute for load curtailment expenditures. Faced with increasing reserve margins, some utilities capped participation in load curtailment programs or allowed their authority to expire. In other cases, the RTP programs supplanted conventional load curtailment programs.

[43]The term "private demand trading center" refers to an entity that serves as a broker between customers who want to sell demand call options and entities (including ISOs, load-serving entities, generators, and even speculators) that want to add them to their portfolios.

benefits in regional and national terms. Before turning to those topics, however, it is important to discuss some criticisms or concerns that have been expressed about incorporating DR into RTO operations. There are at least five arguments:

- *Implementing DR Is Not a Proper Role for the RTO.* Some argue that by facilitating DR the RTO would be overstepping its charter. The RTO's charter includes operating spot markets to ensure the efficient pricing of balancing energy transactions and to support the commercial interests of its members. To implement DR, however, the RTO would have to take on a market-maker role. Unlike most other market transactions, incentive payments made by the RTO to DR participants would not be assignable to specific counterparties for settlement; the only way the RTO would be able to cover such payments would be through a general assessment on all market participants. Some construe this as equivalent to the RTO's underwriting of the transactions.

  In fact, that is exactly what transpires in some existing DR programs, but such actions are not limited to DR. To achieve a reliable and least-cost schedule and dispatch, the RTO makes so-called "uplift" payments to generators to ensure that they recover their cost of production, regardless of when and how they are dispatched. These costs are collected from all buyers, as are other costs associated with payments to ensure the availability of ancillary services resources, under the same reasoning. Seen in this perspective, payments to DR participants to accomplish a similar end appear plausible and reasonable as an RTO responsibility.

- *Payments to Participating Consumers Are "Subsidies."* Some critics have labeled the recovery via uplift of funds to cover curtailment payments as a subsidy, which is not necessarily an appropriate characterization. A subsidy is a payment made to a producer that enables it to market its output at a price below its marginal cost, implying that but for this payment, the producer would not be competitive. DR payments by the RTO could be set to reflect the marginal value of supply, no more and no less, which is the basis on which generators are paid for their output. In other contexts, a frequent criticism of recovering some costs via uplift is that uplift inappropriately spreads costs across all participants, and that certain types of costs should be focused more narrowly on particular parties. However, given that DR demonstrably benefits most (though not necessarily all)[44] consumers, cost recovery via uplift appears practical and defensible.

- *DR Participants Would Receive Double Payments.* This argument holds that a DR payment to curtail consumption constitutes a double payment, because the customer also enjoys the benefits of the savings from not consuming. This is not very persuasive, because the decision not to continue with planned consumption involves costs and inconvenience, and the savings from not consuming might not be sufficient to motivate the desired curtailment without the incentive of a payment from the RTO. Further, many large industrial customers would shift consumption to another time, so whether they would realize savings would depend on whether the rates were lower in the alternate period. Customers who are served at a typical tariff rate could reduce their costs somewhat by reducing discretionary consumption, but the resulting reductions would be small in comparison with the total benefits reaped by all consumers.

- *Excessive Measures To Reduce Price Spikes Via DR Could Inhibit Timely Investment in New Generation or Increase the Cost of Meeting Resource Adequacy Requirements.* Some analysts believe that the higher profits generators earn during periods of relative scarcity are important to inducing timely investment in new generating capacity. Overstimulation of DR through incentive payments by RTOs could reduce investment incentives. But in that event, the cost of meeting resource adequacy requirements by purchasing reserves in regional capacity markets would increase, prompting new investment. RTOs would have to maintain an

[44]In most regions, a large fraction of total electricity is sold at wholesale through long-term bilateral contracts, and the remainder is sold through short-term markets. The size of the fraction sold through the short-term markets is likely to vary over time and from region to region. Thus, the level of total immediate benefits to consumers associated with a wholesale price reduction triggered by DR would depend on how much of their electricity was being purchased on the short-term market. Further, across the region, some retail sellers would be more dependent on the short-term market than others, so that the benefits of a price reduction in the wholesale market would not be evenly distributed among consumers. If the price volatility of short-term markets were abated, however, retailers would be more inclined to acquire resources in those markets, at least until bilateral contract prices were also adjusted downward.

appropriate balance between reducing price spikes in the short-term market via DR and increasing the long-term costs of maintaining resource adequacy.[45]

- *DR Programs Could Be "Gamed" by Some Consumers.* That is, some consumers could be paid to curtail at times when they never had any intention of consuming electricity, or they could receive windfalls for other reasons. DR programs must in some way estimate what a participating customer's consumption pattern would have been had the curtailment not occurred. The use of sophisticated protocols to make such estimates based on a customer's past consumption patterns minimizes the risks and costs of gaming relative to the overall benefits of the program.[46] Some windfalls result from coincidence and are simply unavoidable; for example, a participant in an emergency DR program might decide for its own reasons to shut down a plant just before the RTO called for a curtailment, and put in a claim for payment. DR bidders planning to shut down a facility might be inclined to submit very low curtailment bids in hopes of realizing a windfall payment. However, experience with DR programs to date suggests that bid floors combined with surveillance by market monitoring are sufficient to minimize such behavior.[47]

Although there are important long-term issues to be resolved regarding the role and provision of DR, the case for considering it in the context of market design is strong. Low-cost, low-risk, high-value programs can be implemented quickly by the RTO, leveraging its other investments in system operations and settlement.[48] Many programs require only a small investment in metering to participate and assess no penalty, thereby providing customers with a risk-free opportunity to acquire experience in managing their loads in response to wholesale market conditions.[49] Retailers and brokers are motivated to promote participation because they can deliver cash to customers. Moreover, it provides them with a basis for establishing a more permanent and involved relationship with customers by supplying communication and enabling technologies to help them respond and extending the relationship to other services. Because the value is tied to transparent RTO markets, customers learn what their curtailment actions are worth upstream, enabling them to evaluate participation opportunities from competitive brokers. Finally, because the RTO establishes the value of DR based on a total market perspective, the benefits generated improve the market's performance to the benefit of all stakeholders.

Programmatic Approaches to Integrating DR into RTO Market Operations

Several ways of integrating short-term DR into RTO market operations are described in Table 4.2. In each case, DR resources can be scheduled or dispatched by the RTO so that they improve system reliability or reduce the overall cost of meeting demand. As the examples in the table indicate, these DR programs have already been implemented by existing RTOs (or ISOs), in some cases in significant numbers. Regulated and competitive retailers acting as DR brokers recruited virtually all participants. The NYISO reported more than 1,600 participants in its emergency program and realized an average of about 650 MW of curtailments over 10 event hours in the summer of 2002. PJM has used the 1,200+ MW of curtailment reserves participating in its emergency and automatic load management (ALM) program over several hours during the past three summers. More than 500 MW of load is reported to be participating in ERCOT's ancillary services programs in Texas.

45NYISO has recently instituted new pricing rules whereby the price paid to loads curtailed under its emergency program can set the real-time market price. Curtailment bids in the day-ahead market can set the market-clearing price by design.

46A recent report commissioned by the California Energy Commission describes the forms of bias associated with alternative CBL (Customer Baseline Load) protocols. Xenergy, Inc., *Protocols for the Development of Demand Response Calculations*. Prepared for California Energy Commission (August 2002).

47NYISO imposed a $50/MW floor price on curtailment bids and included such bids under the surveillance of market monitoring.

48For example, in 2 years NYISO has built up participation in its emergency DR program to more than 1,700 customers, who have provided up to 825 MW of load curtailment at an annual cost of about $4 million.

49Market research has identified penalties as a major barrier to participation in DR programs; however, it also has revealed that the strong risk aversion is associated with customers' lack of understanding of what they can curtail, and how wholesale markets create opportunities to benefit from dong so. Allowing customers opportunities to experience their DR capability for themselves at low risk can reduce these inhibitions. See Neenan Associates and CERTS, *How and Why Customers Respond to Electricity Prices: A Study of NYISO and NYSERDA PRL Programs*. Prepared for NYISO and NYSERDA (January 2003).

Estimating the Value of Demand Response

This section describes the method used to estimate a range for the potential annual benefits associated with tapping DR resources in the 16 U.S. regions covered by this analysis. It is important to understand that there is a high degree of uncertainty associated with these calculations, and they are presented as illustrative rather than definitive projections of potential benefits. Their purpose is to demonstrate that it is reasonable to believe that large benefits are achievable in this area, and that further work by a wide range of affected parties is needed to gauge their magnitude more accurately and determine how they would best be achieved.

Methodology

The DR valuation has two components, one that estimates the benefits from a day-ahead curtailment bidding program and another that estimates the benefits of dispatching DR resources to ease reserve shortfalls under emergency or near-emergency conditions. Both kinds of programs are assumed to be fully integrated into RTO operations. Secondary benefits, such as reduced deadweight losses associated with inefficient pricing, the effects of reduced spot market volatility on bilateral market transactions, and the value of DR as a restraint on the exercise of market power, are also potentially large, but gauging them is beyond the scope of this analysis.

The assumptions and inputs employed are described in Table 4.3 (curtailment bidding DR) and Table 4.4 (Emergency DR), along with a description of the calculated outputs. The regional average summer afternoon loads and prices for 2005 produced by POEMS were assumed to define the underlying regional market supply curve (as depicted in Figure 4.2) at the junction of its first and second segments, which is defined as being 80% of the maximum load experienced during the period. The second and third segments of the supply curve are specified by assuming a supply structure comparable to that of the NYISO day-ahead market.[50] A key feature of the supply structure is the relative elasticity of supply, or supply flexibility, defined as the percentage change in price resulting from a 1 percent change in supply, which in turn determines the slope of the supply curve segment. The steeper the supply curve, the higher the supply flexibility and the greater the potential impact of DR on market-clearing prices.

Table 4.2. Integrating DR into ISO Market Operations

Role	Description	Examples
DR as a Capacity Resource		
Scheduled Ancillary Services. . . .	Closely monitored loads that can undertake curtailments on short notice provide spinning and non-spinning reserves, and are paid standby and real-time energy market prices. Noncompliance penalties are assessed.	ERCOT LaaR, ISO-NE Class I, CAISO
Installed Capacity.	Loads curtailable on 1 or more hours notice can sell that capacity as ICAP and receive the prevailing market value.	NYISO, ICAP/SCR, PJMISO ALM, CAISO
Emergency Reserves.	Loads that curtail with 2 or more hours notice to correct a reserve shortfall are paid the market energy price, subject to a floor, with no noncompliance penalty.	CAISO, PJMISO, and NYISO offer such programs
DR as an Energy Resource		
Day-Ahead Market Scheduled . . .	Loads bid curtailments into day-ahead markets where they are scheduled if they reduce overall supply costs and paid market-clearing price, subject to a noncompliance penalty.	NYISO and PJMISO (implemented), ISO-NE (planned)
Real-Time Dispatch	When real-time market is forecast to reach a specified price level, customers that curtail are paid prevailing market price, in some cases with floor. No noncompliance penalty.	ISO-NE Class 2, PJMISO, ERCOT BUL

[50] See Neenan Associates and CERTS, *How and Why Customers Respond to Electricity Prices: A Study of NYISO and NYSERDA PRL Programs* (January 2003), Section 6, for details on how supply flexibilities are developed from market data.

The value of DR in abating price spikes depends on the amount of load that is curtailed, the supply flexibility, the amount of load served in the day-ahead market, and the number of times that prices reach the level that triggers scheduling curtailments. In this analysis, the benefits attributable to this component of DR are the savings realized by buyers when DR curtailments reduce market-clearing prices. Several scenarios were constructed to illustrate the impact of the slope of the supply curve, the amount of load settled, and the level of customer participation on the value of DR resources bid into the day-ahead market.[51]

The assumptions used to estimate the value of programs to dispatch DR to ease emergency or near-emergency situations are listed in Table 4.4. All regions are assumed to encounter reserve shortfall episodes. Emergency DR resources are dispatched to rectify the situation, and consumer benefits are created by improving system reliability. The valuation methodology requires specification of the size of the shortfall; the improvement in reliability, measured as the change in loss-of-load probability (LOLP) resulting from DR; the amount of system load at risk of a forced outage; and the number of shortfall events encountered annually.

Table 4.3. Modeling the Value of Day-Ahead Curtailment Bidding DR Resources

Assumptions	Source
DR as percentage of load	Scenario specific
Percentage of load settled in day-ahead market	Scenario specific, NYISO data
Low supply flexibility, day-ahead market	Equal to 4, based on NYISO estimate for a relatively unconstrained region
Medium supply flexibility, day-ahead market	Equal to 5, based on NYISO estimate for a relatively unconstrained region
High supply flexibility, day-ahead market	Equal to 6, based on NYISO estimate for a relatively constrained region
Number of events per season	Scenario specific, NYISO experience
Number of events per season	20 events, each of 4 hours duration, for the low and medium SF cases, 25 for the high SF case
Curtailment bid strike price	Assumed to be $150/MWh in all cases
Inputs	
Average load, 12:00-6:00 p.m. period, summer	POEMS/MAPS projections by region for 2005
Average price, 12:00-6:00 p.m., summer	
Outputs	
Event hour load, no DR	Model assumes that average load and price correspond to first segment of supply curve. It estimates the higher event load and price and the subsequent load and price reductions from DR, and the corresponding value in terms of lower cost to buyers in the day-ahead market.
Event hour price, no DR	
Event hour load, with DR	
Event hour price, with DR	
Event hour value, with DR	
Season DR value to day-ahead buyers	

Table 4.4. Modeling the Value of Emergency DR Resources

Assumptions	Source
DR as percentage of load	Scenario specific
Percentage of load at risk of an outage	Scenario specific
Value of lost load	Scenario specific
Inputs	
Average season load, 12:00-6:00 p.m.	POEMS/MAPS projections by region for 2005
Average price, 12:00-6:00 p.m.	POEMS/MAPS projections by region for 2005
Improvement in loss-of-load probability due to DR	Scenario specific
Outputs	
Value of improved reliability	Regional value of emergency DR for 2005

[51]For example, about 35 percent of total retail supply is purchased in the day-ahead market in NYISO, but zonal percentages within NYISO's footprint vary.

Valuation Results

Several scenarios were evaluated to demonstrate the effects of the assumptions on the valuation of the two categories of DR resources. Table 4.5 describes the scenarios constructed to characterize the value of DR bidding. Table 4.6 describes the scenarios used to illustrate the value of emergency DR programs. In each table, the first scenario represents a relatively conservative set of assumptions, and subsequent scenarios involve more ambitious assumptions about the load participating and its impacts on the market, resulting in higher levels of projected benefits.

The results displayed include the total U.S. annual valuation and the regional breakdown. They are intended to illustrate the implications of the assumptions employed; they are not adjusted to reflect the current or projected supply conditions in the regions. For example, in the DR bidding scenarios, the low supply flexibility case (SF = 3) might be construed as representing the situation where reserves are generally sufficient and a forced plant outage or an episodic shift in demand, perhaps due to weather, would cause prices to rise but not dramatically. The medium case (SF = 4) represents a control area or zone where reserves are not as adequate, and as a result prices rise more dramatically under tight conditions. The high case (SF = 6) reflects a very steep supply curve. The SF values correspond to values derived from actual day-ahead market data for NYISO zones that exhibit those reserve characteristics.[52]

The estimated annual benefits for bidding DR are shown in Table 4.7. Scenarios 1-3 represent low DR participation (2 percent) and relatively low day-ahead market activity (assumed to be 20 percent of all market transactions), with values corresponding to the three SF levels described above. The subsequent sets of scenarios involve combinations of more load in the market (scenarios 4-6), more DR participation (scenarios 7-9), and the two situations combined (scenarios 9-12).

Under the most conservative cases, the annual benefits are modest ($80 million), but the low value reflects the relatively low need. As the SF increases (across the rows of Table 4.7) or the assumptions driving the value are increased (down the columns) the value increases, especially between the medium and high SF market characterization. It is difficult to project that the entire United States would simultaneously be faced with the reserve conditions of scenario 12, which would yield more than $767 million in benefits; however, such conditions would apply simultaneously to load pockets in many regions at the same time, and virtually every region is likely to experience at least a few days a year when prices will be elevated and DR curtailment bids would be accepted.[53]

Figure 4.3 illustrates the projected regional distribution of benefits. The distribution reflects differences in the relative peak summer usage level and prices in each region as produced by the POEMS model for 2005. Note the nonlinear effect of the SF on the level of benefits, which expresses the steeper nature of the supply curve. DR resources are most valuable when reserves are short. A more detailed analysis of regional supply conditions and reserve margins would enable a more accurate measure of the value of DR bidding programs.

Emergency DR resources are estimated to provide between $85 million (scenario 1, Table 4.8) and $340 million (scenario 3, Table 4.8) in benefits annually. The lower level of benefits represents conditions that characterize some of the event

Table 4.5. Scenario Assumptions: DR Bidding Valuation

Scenarios	% DR	% Load Transacted	Supply Flexibility
1-3	2%	20%	L, M, H
4-6	2%	30%	L, M, H
7-9	5%	20%	L, M, H
10-12	5%	30%	L, M, H

Table 4.6. Scenario Assumptions: Emergency DR Valuation

Scenario	% DR	% Load at Risk	Change in Loss-of-Load Probability	Value of Lost Load*	Events
1	2.5%	5%	15%	2,500	20
2	2.5%	5%	20%	2,500	20
3	2.5%	5%	25%	2,500	20

*Dollars per megawatthour.

[52] See Neenan Associates and CERTS, *How and Why Customers Respond to Electricity Prices: A Study of NYISO and NYSERDA PRL Programs* (January 2003).

[53] In the NYISO, prices exceed $100/MWh for as few as 20 hours a year in some zones and for more than 100 hours a year in other zones.

days experienced by the NYISO in 2002, where the loss-of-load probability (LOLP) improvement was important but not dramatic. The high case (scenario 3) reflects conditions similar to those of a day in 2001 in the NYISO, when reserve shortages were more critical. All cases use the relatively conservative $2,500/MWh for value of lost load (VOLL), and assume a conservative 20 hours of curtailments per year.[54] Some regions could encounter more than 20 summer hours when DR resources would be dispatched, and others could use them also in winter, which would also increase the level of benefits.

The distribution of benefits across the regions is illustrated in Figure 4.4. The relative size of the load served is largely responsible for the regional differences. A more accurate representation of the value would require characterizing localized reserve situations and the degree of transmission congestion.

In summary, DR programs in association with RTOs and LMP have the potential to preserve the benefits of existing load management capability that are vulnerable to being lost in restructuring of the industry. In addition, DR could provide additional benefits from more efficient pricing, scheduling, and dispatch of resources; however, isolating the contributions from pre-existing load management programs would require estimating the benefits from such programs, an effort that is beyond the scope of this study.

Table 4.7. Total U.S. Benefits: DR Bidding, 2005

Scenarios	Low SF	Med SF	High SF
1-3	$79,703,267	$123,303,570	$238,069,920
4-6	$123,982,860	$191,805,553	$370,330,987
7-9	$158,702,687	$241,932,498	$460,377,012
10-12	$264,504,478	$403,220,830	$767,295,021

Table 4.8. Total U.S. Benefits: Emergency DR, 2005

Scenario	Value
1	$85,026,293
2	$170,052,586
3	$340,105,172

Figure 4.3. Regional DR Bidding Benefits in 2005 by Region, Scenarios 1-3

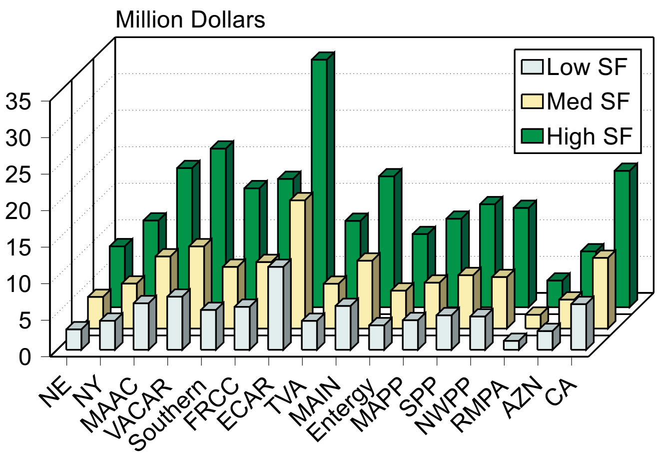
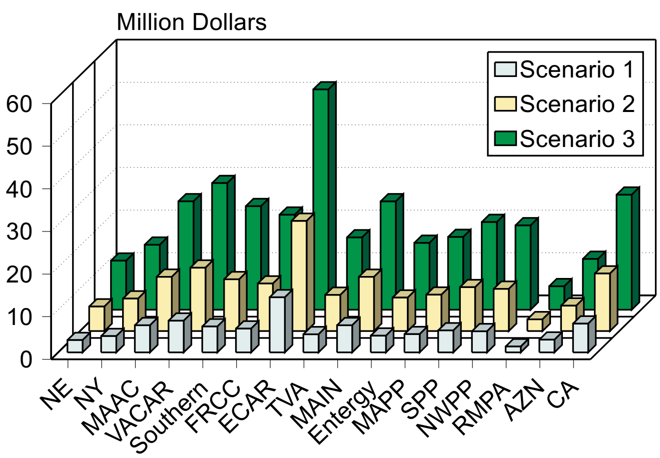


Figure 4.4. Regional Emergency DR Benefits in 2005 by Region, Scenarios 1-3



[54]PJM and NYISO have used emergency DR resources for 10 to 20 hours in each of the past 2 years. During the California crisis, one California utility used all 100 hours of curtailments it had available in the first 2 months. Gulf Power's air conditioning control program allows for 80 hours of curtailment annually.

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