

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

May 12, 2006

OFFICE OF THE COMMISSIONER

Ms. Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Joint Boards on Security Constrained Economic Dispatch
Docket No. AD05-13-000

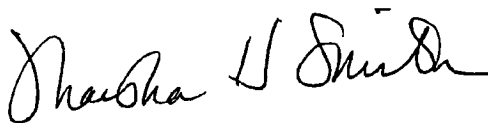
Dear Secretary Salas:

In accordance with the Commission's order of September 30, 2005,¹ we are filing the attached Study and Recommendations Regarding Security Constrained Economic Dispatch on behalf of the Joint Board on Economic Dispatch for the West Region. The members of the Joint Board are:

Commissioner Suedeem G. Kelly, Federal Energy Regulatory Commission, Chair of the Joint Board
Commissioner Marsha H. Smith, Idaho Public Utilities Commission, Vice Chair of the Joint Board
Commissioner Marc L. Spitzer, Arizona Corporation Commission
Commissioner Dian M. Grueneich, California Public Utilities Commission
Chairman Gregory Sopkin, Colorado Public Utilities Commission
Commissioner Thomas J. Schneider, Montana Public Service Commission
Mr. Richard L. Hinckley, General Counsel, Public Utilities Commission of Nevada
Commissioner E. Shirley Baca, New Mexico Public Regulation Commission
Chairman Lee Beyer, Oregon Public Utility Commission
Commissioner Dustin Johnson, South Dakota Public Utilities Commission
Commissioner Barry Smitherman, Public Utility Commission of Texas
Chairman Ric Campbell, Utah Public Service Commission
Chairman Mark Sidran, Washington Utilities and Transportation Commission
Deputy Chair Kathleen A. "Cindy" Lewis, Wyoming Public Service Commission



Commissioner Suedeem G. Kelly, Chair
Joint Board on Economic Dispatch
for the West Region



Commissioner Marsha H. Smith, Vice Chair
Joint Board on Economic Dispatch
for the West Region

¹ Joint Boards on Security Constrained Economic Dispatch, 112 FERC ¶ 61,353 (2005).

**Executive Summary:
Recommendations of the Federal/State
Joint Board on Economic Dispatch for the West Region**

On September 10, 2005, the Federal Energy Regulatory Commission (the Commission) issued its Order Convening Joint Boards Pursuant to Section 223 of the Federal Power Act “to study the issue of security constrained economic dispatch for the various market regions,” “to consider issues relevant to what constitutes ‘security constrained economic dispatch’ and how such a mode of operating . . . affects or enhances the reliability and affordability of service,” and “to make recommendations to the Commission.”¹

The West Joint Board consists of the Federal Energy Regulatory Commission and the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington and Wyoming.²

Our analysis of security constrained economic dispatch (SCED) began with the Commission’s definition in the Order: “the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.” In the Report, we discuss the basics of SCED and how it functions in the Western Interconnection. Below are short summaries of the major issues considered by the Board and our recommendations to the Commission in this Report.³ We also address three recommendations made to the Joint Boards by the DOE in *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*.

1. Independence of dispatcher.

The Board examined the suggestion that independent transmission dispatch was needed to ensure fairness and the full integration of the all generation facilities into the dispatch without regard to ownership of those facilities.

Recommendation:

We recommend that independent dispatch entities not be created for their own sake. We do not recommend further analysis at this time. If any further analysis is deemed

¹ The Order was issued in Docket No. AD05-13-000, Joint Boards on Security Constrained Economic Dispatch.

² These states are within the Western Interconnection, with the exceptions of South Dakota and Texas, only portions of which are served from within the interconnection.

³ Texas’s recommendations diverge from the majority, and are contained in the *Texas Perspective on Security Constrained Economic Dispatch*, filed separately in Docket No. AD05-13-000.

warranted, it must include an investigation of the potential benefit to consumers. If further work appears justified on the facts, the affected states and relevant utilities should determine the nature of the dispatching entity to be considered. Where public, cooperative and privately owned entities serve the market under consideration, their participation should be encouraged.

2. Utility dispatch of third party power through contracts.

The Board examined the question of whether the relationship between dispatching utilities and IPPs should be governed by contract to ensure the high level of reliability and responsiveness needed for the dependable dispatch of contract units as fully functional integrated grid resources.

Recommendation:

We encourage, but do not wish to duplicate, the efforts of EPSA and EEI in developing standard contractual language addressing reliability, dispatchability and other issues. The Joint Board recommends the use of contractual commitments by IPPs to provide capacity, energy and ancillary services in a manner consistent with an LSE's dispatch needs. Integrating IPPs into the dispatch in the Western Interconnection should be overseen by WECC on an interconnection-wide basis, or subregionally by an appropriate entity.

3. Transparency of dispatch information and processes.

The Board examined the question of whether a central entity, dispatching all of the resources in a region, that had more timely access to high quality information could function more efficiently and better realize the value of SCED. For competitive reasons, some entities are reticent about sharing confidential dispatch and load information with a non-independent dispatching entity.

Recommendation:

Achieving transparency is not sufficient by itself to justify the creation of an independent dispatch entity. We recommend that the Department of Energy study ways to improve the accuracy of forecasting to improve economic dispatch and identify savings that could be achieved thereby.

4. Consolidation of control areas in a region.

The Board looked at the question of whether consolidation of control areas might yield better information which might, in turn, enable more efficient dispatch than would be the case if several control areas simply shared information. The benefits of larger control areas for renewable technologies such as wind were discussed as was the range of information available from WECC and otherwise to smaller control areas.

Recommendation:

We recommend that the states, individually or jointly, consider further consolidation of control areas. Further studies should take into account [i] the value of larger control areas for renewables such as wind, and [ii] solving the problems of large control areas in scheduling within the hour. Any consolidation decision should be based on the needs of consumers and the region's economy for reliable and affordable power; and we recommend that consolidation not be thought of as a goal in itself. Enlargements should be approached on a case-by-case basis with the assistance of WECC and possibly the WSPP.

5. Import/export schedule changes within an hour.

The Board learned that large changes in load and large amounts of imported power make it difficult to schedule efficiently for the hour in some markets. Slow ramp rates can cause imbalances when scheduling for the hour.

Recommendation:

We recommend that the WECC develop a standard west-wide protocol to address the need for scheduling before, during and after the hour.

6. Some practical limitations on economic dispatch.

The Board recognizes that the physical makeup of the grid, the demands placed on it and the available generation resources sometimes impose cost, reliability and other limitations on economic dispatch to assure that the needs of the public are accommodated. Various state and regional policies also emphasize goals that go beyond "pure" economic dispatch.

Recommendation:

We recommend that the definition of security constrained economic dispatch be flexible and broadened to include other public policies, values and physical and operational constraints as well as costs.

7. First DOE Recommendation: review dispatch practices.

The DOE recommends that the Joint Boards review selected dispatching entities to determine how they conduct economic dispatch and document the rationale for deviations from "pure" least-cost economic dispatch.

Recommendation:

The Board recommends that this study not be pursued. Such a study would take us deeply into variables and deviations from "pure" economic dispatch without providing

much value. It is at odds with our fundamental conclusion that economic dispatch must remain a flexible concept.

8. Second DOE Recommendation: standardize dispatch contract terms.

The DOE recommends that it and FERC encourage stakeholders to develop more standard contract terms concerning price stability, dispatchability, reliability, and penalties for not meeting performance standards.

Recommendation:

We recommend that the standardization of dispatch contract terms be pursued on a regional basis rather than on a national basis. The regional variances in transmission grid operating parameters throughout the Western Interconnection make a strong case for allowing development to go forward on a regional basis.

9. Third DOE Recommendation: review dispatch tools.

Existing economic dispatch technology, including software and data used and the underlying algorithms and assumptions, deserve scrutiny.

Recommendation:

We recommend the development and refinement of technological tools to make the best use of existing and proposed facilities.

I. Introduction

This Report of the West Joint Board on Economic Dispatch presents the results of the Joint Board's study of security constrained economic dispatch (SCED) issues, and provides recommendations to the FERC. The West Joint Board is one of four joint boards designated by the Commission under EPCRA 2005, Section 1298, Economic Dispatch. The members of the West Joint Board are:

Commissioner Suede Kelly, Federal Energy Regulatory Commission, Chair of the West Joint Board

Commissioner Marsha H. Smith, Idaho Public Utilities Commission, Vice Chair of the West Joint Board

Commissioner Marc L. Spitzer, Arizona Corporation Commission

Commissioner Dian M. Grueneich, California Public Utilities Commission

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Chairman Ric Campbell, Utah Public Service Commission

Chairman Mark Sidran, Washington Utilities and Transportation Commission

Deputy Chair Kathleen A. "Cindy" Lewis, Wyoming Public Service Commission

The West Joint Board met in public session on November 13, 2005 in Indian Wells, California and on February 13, 2006 in Washington, D.C.

As the Commission noted in the initial order convening the joint boards:

Each joint board is authorized: (1) "to consider issues relevant to what constitutes 'security constrained economic dispatch'"; (2) to consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned"; and (3) "to make recommendations to the Commission regarding such issues."

This report contains four sections in addition to this introduction: Section II provides a description of the basic concept of SCED used in the study; Section III provides background on the variations in dispatch procedures in the west; and Section IV gives a summary of the issues raised and considered by the Joint Board, together with recommendations to address these issues. The principal source material for this Report include [i] presentations to the Joint Board, [ii] written comments submitted to the Joint

Board, [iii] discussions among the Joint Board members at Board meetings and otherwise, [iv] the DOE report under EPOA 2005, Section 1234⁴, and [v] the responses to the DOE survey of economic dispatch under Section 1234.

II. Security Constrained Economic Dispatch: the Basics

For purposes of the joint boards' studies, the FERC adopted the following definition of security constrained economic dispatch:

“the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.”⁵

This definition describes the basic way all utilities in the region endeavor to dispatch their own and purchased resources to meet electricity load. The basics of SCED are described in this section to establish a common understanding of the process before addressing issues and recommendations.

There are a number of unique challenges to supplying electricity: production must occur simultaneously with demand; demand varies greatly over the course of a day, week, and seasons; the costs of generation from different units and different types of units vary greatly; and scheduled and unplanned outages in a generator fleet and expected and unexpected conditions on the transmission network affect which generation units can be used to serve load reliably. SCED is an optimization process that takes account of these factors in selecting the generating units to dispatch to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

The economic dispatch process occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, operators must decide which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term “day ahead”), based on the load forecast. In selecting the most economic generators to commit, operators must take into account each unit's physical operating

⁴ *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005.

⁵ September 30, 2005, Order at ¶14.

characteristics, such as how quickly output can be changed, maximum and minimum output levels, and minimum time a generator must run once it is started. Operators must also take into account generating unit cost factors, such as fuel and non-fuel operating costs and costs of environmental compliance.

Operators must also consider other factors that may affect what resources should be included in the next day dispatch, such as required environmental limits on annual unit output, and non-power uses of hydro resources. These factors can affect the eventual cost of utilizing the resource, but cannot be easily translated into daily or hourly production costs.

In addition, conditions that can affect the transmission grid must also be taken into account to ensure that the optimal dispatch can meet load reliably. This is the “security” aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, transmission path congestion (line capacities as affected by loading levels and flow direction), inadvertent loop flow and the weather. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive but better situated generators may have to replace cheaper units.⁶ Operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day dispatch.

In the *unit dispatch* stage, operators must decide in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall production costs are minimized while the necessary level of service is maintained. Actual conditions will vary from those forecasted in the day-ahead commitment and operators must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz (per NERC standards). This is usually done by using Automatic Generation Control (AGC) to change the generation dispatch as needed. In addition, transmission flows must be monitored to ensure that they stay within reliability limits and voltage stays within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load. Operators may check conditions and issue adjusted unit dispatch instructions as often as every five minutes. The Western Electricity Coordinating Council (WECC) provides reliability related service throughout the Western Interconnection and closely monitors the condition of the network.

⁶ This is known as “out of merit” dispatch.

III. Economic Dispatch in the West

The practice of economic dispatch in the West varies by area. For purposes of this report, we will organize the discussion around the four areas used by WECC. These subregions⁷ are shown in Figure 1 and are as follows:

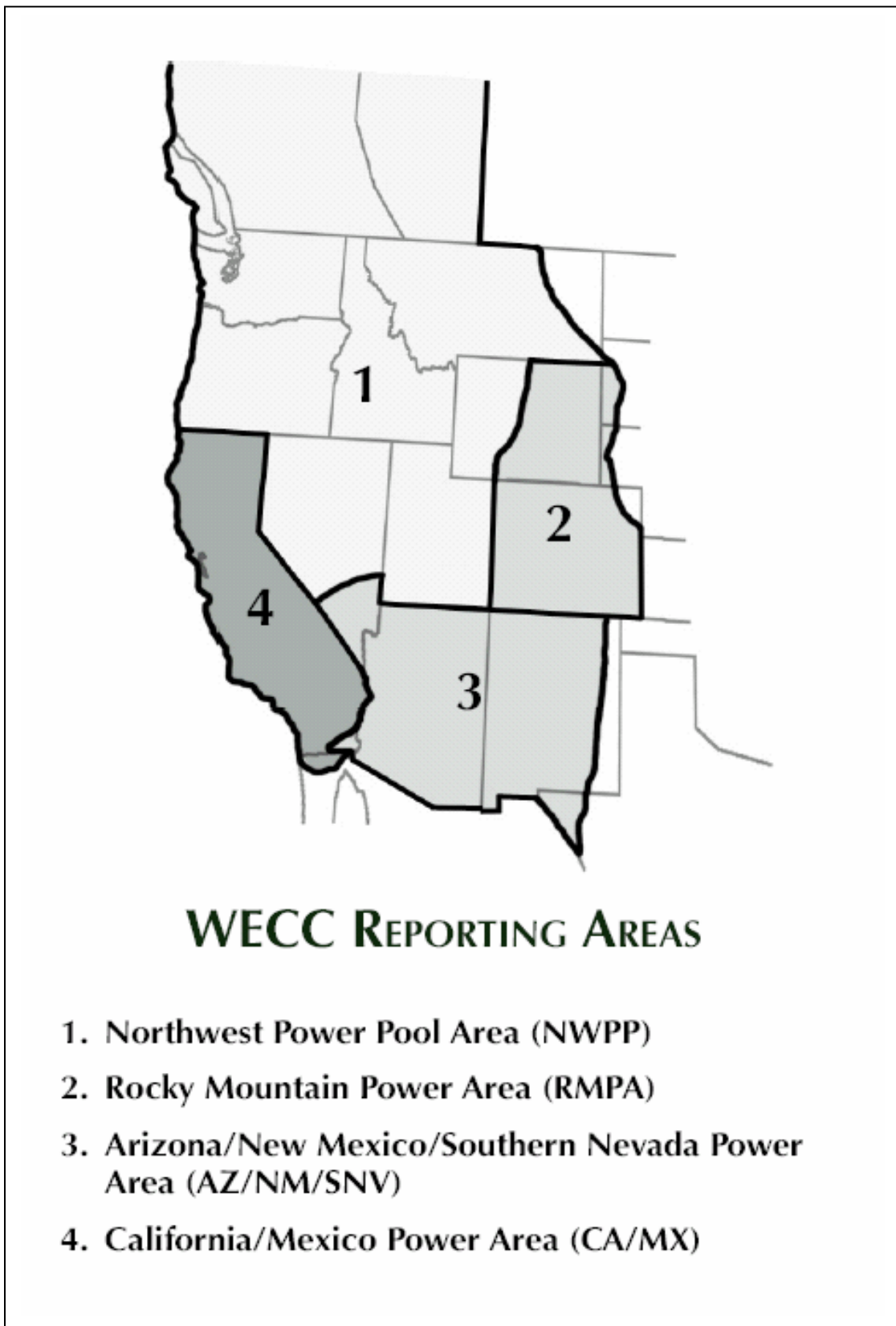
- Northwest Power Pool Area (Northwest)
- California-Mexico Power Area (California)
- Arizona-New Mexico-Southern Nevada Power Area (Southwest)
- Rocky Mountain Power Area (Rockies)

The overall pattern of dispatch in the West depends to a large extent on differences between the resources and loads in each area. The Northwest has an abundance of hydropower and a load that peaks during the winter, while the Southwest has a load that peaks during the summer. As a result, a historical pattern of flows has developed where power in the summer flows from available hydropower in the north to peak loads in the south, while power in the winter flow from south to north to meet the peak loads in the northwest. The north-south transmission system has developed to support this pattern, and provides for overall economic utilization of generation resources when water conditions permit. In a similar way, the main fuel sources for thermal power generation, coal and natural gas, tend to be in the Rockies or to the east in Texas and Oklahoma, while the major population centers are to the west, in California and the Pacific Northwest. The electric transmission systems reflect the need to move power west from coal generation; this movement of power is less seasonal than the north-south movement, as much of the power comes from baseload plants that run year round.

The CAISO is the one multi-utility area market in the west that is centrally organized and dispatched. The remainder of the areas in the west perform economic dispatch on a cooperative but decentralized basis, with a form of control area or utility dispatch similar to the basic dispatch described in the previous section. However, there is considerable variation in individual practices in each area that distinguish the way economic dispatch is practiced. The variations in regional practice are discussed briefly below.

⁷ Because the Western Interconnection is coextensive with the area being studied by the West Joint Board, Commissioner Smith recommended using the term “subregion” when referring to less than the entire Western Interconnection region. Transcript of February 13, 2006, meeting of West Joint Board, hereinafter Tr. 2, pp. 49-50.

Figure 1. Western Regions for Economic Dispatch Discussion



A. Northwest

Although significant hydropower resources exist throughout the west, they dominate power generation in the Northwest. Fifty eight percent of capacity in the Northwest is conventional hydropower; seventy nine percent of the total western hydropower resources occur in the Northwest.⁸ In the west as a whole, hydropower accounts for thirty four percent of the total capacity.⁹ This level of hydropower resources alters the way economic dispatch is performed in the Northwest and in the entire west, making western dispatch issues significantly different from those in the Eastern Interconnection and ERCOT.

Several characteristics of hydropower have direct implications for dispatch in the Northwest:

- Economic dispatch needs to consider the overall optimization of hydropower and thermal resources, making the problem of resource optimization much more difficult than it is in a power system based exclusively or primarily on thermal resource capacity.
- Hydropower generation resources in the Northwest are highly interdependent, so that they need to be dispatched as a coordinated system for power generation, rather than as separate, independent power sources.
- Conventional hydropower is generally limited by the total available energy stored in the water behind the dams, not by the total generating capacity of the resource.
- Hydropower can generally be dispatched very quickly when available, providing an abundance of low cost, rapidly dispatchable capacity to an extent not present in the other North American interconnections.

These characteristics have led to a long history of coordination in the Northwest, beginning around 40 years ago with the Columbia River Treaty with Canada and the Pacific Northwest Coordination Agreement (PNCA), and including the Mid-Columbia Hourly Coordination Agreement (MCHA). The PNCA enables both Federal and Non-Federal projects to operate as a single utility owner to optimize power and nonpower river demands, while the MCHA optimizes the hydraulic operation of seven dams on the Columbia River. The MCHA permits hydropower resources to provide load following for much of the Northwest load, and hydropower resources also provide regulation and reserves at a low cost.

⁸ WECC, 2005 Information Summary, Total Existing and Planned Generation, p. 6.

⁹ *Id.*

Another factor affecting Northwest dispatch is operation of BPA's transmission assets, which are closely connected to the operation of hydropower resources. Historically, the coordinated operation of the system of dams meant that all power was treated equally regardless of location on the system, so that a megawatt had the same value at any location. Until relatively recently, there were few constraints on the BPA transmission system, so there was sufficient transmission capacity to ensure that coordination would work successfully. In the last few years, there have been an increasing number of internal constraints; and BPA is now moving toward a power flow based methodology to more accurately capture transmission effects in dispatch.¹⁰

The coordination of power and non-power uses leads to determining the optimum power operation *within* the non-power constraints. This optimum operation is distinct from the objective of minimizing short term operating costs. The valuation of hydropower resources for short term dispatch presents unique challenges when such a high percentage of resource is low cost in the short term and potentially high (and uncertain) in value over the longer term.

Although the presence of hydropower in the Northwest significantly affects the overall operation and dispatch of the power system, the basic dispatch remains decentralized and economic dispatch is conducted on a utility by utility basis rather than being coordinated centrally. Plans for the development of a RTO in the Northwest are not being actively considered; but Columbia Grid has recently begun efforts to form a grid organization in the Pacific Northwest.

Based on the responses to the DOE survey and the utility presentations at the initial meeting of the West Joint Board, utility dispatch in the Northwest is similar to the basic model described in the Section II, once operations are adjusted for the presence and limitations of hydropower. The main difference is less emphasis on day-ahead unit commitment of thermal resources to provide load following and reserves, because hydropower is generally the lowest cost alternative for these functions and will be used when available. Utilities report dispatching a mix of their own generation, independent generation committed under contract, and wholesale spot market purchases, combined to achieve the lowest cost from the resources available. These dispatch decisions are generally made before the operating day, either in the day ahead planning or earlier, and take into account factors other than strict operating costs, such as environmental limits, fuel contract terms, opportunity cost of company-owned hydropower, and similar factors.

¹⁰ BPA, Economic Dispatch in the Pacific Northwest, presentation to the meeting of the West Joint Board for the Study of Economic Dispatch, Palm Springs, CA, November 13, 2005. (FERC Docket No. AD05-13-000)

Although planning for dispatch may take into account a wider range of sources, hourly or real time adjustments are often restricted to company owned resources or resources under contract that permit the utility sufficient flexibility in the terms of the dispatch.

B. California

The California ISO (CAISO) performs an economic dispatch covering most of California, with the exception of some control areas.¹¹ Formed in 1998, the CAISO dispatches a single control area, corresponding to the former control areas of California's three largest Investor Owned Utilities. Prior to the formation of the CAISO, each of the three control areas performed single utility economic dispatch, by dispatching their own resources and other resources under their control. This dispatch was similar to the basic dispatch process described in Section II, using the costs of the generation resources to establish the order of the dispatch and running the lowest cost resources available, given the security constraints of the system.

The CAISO consolidated the dispatch of the three utilities into a single dispatch for approximately 45,000 MW of California peak load, by balancing generation and load every 10 minutes based on market bids from generation resources. This balancing market was similar to the previous control area balancing function in that lower cost generation resources were dispatched before higher cost resources; however, the traditional utility costs were replaced by bids to the CAISO. This change altered the economic dispatch process in two fundamental ways: [i] all resources capable of being dispatched were eligible to submit bids on an equal basis, and [ii] the market bids that replaced the utility production cost estimates were no longer required to be tied to actual production costs of the utility.

In October 2004, the CAISO began the Real Time Market Application (RTMA), a new market application that plans a 5 minute dispatch for 2 hours in the future, dispatches online resources on a 5 minute basis in real time, and starts "fast start" resources on a 15 minute interval. A Market Redesign and Technology Upgrade (MRTU), planned for late 2007, will include the use of market bidding for day ahead planning and unit commitment, and greater detail in representation of the transmission grid for more accurate representation of the security constraints in the economic dispatch decision. These changes will enhance the dispatch processes of the CAISO, but will not change the basic differences between the CAISO dispatch and dispatch in the rest of the west: CAISO will continue to perform the only centralized, multiple-utility, market-bid-based

¹¹ Examples of control areas inside California, but not included in the CAISO dispatch are the Los Angeles Department of Water and Power in Southern California, Sacramento Municipal Utility District in Northern California, and a few others throughout the state.

economic dispatch in the west. Although the CAISO is the only area in the West with this type of dispatch, its operation has significant effects on dispatch in the rest of the west because the total load in California is large (approximately thirty percent of the summer peak load for the west)¹² and California relies on significant imports from the rest of the west. Because California is so closely dependent on imports from the rest of the west, and because long distance power transactions are an important factor in overall power flow, the centralized dispatch in the CAISO has greater direct impact on other areas in the WECC than comparably-sized centralized dispatch in the Eastern Interconnection has on other areas in the east.

The CAISO dispatch includes all resources needed to serve the load, both those that can be dispatched on a 5-minute basis and those that are not capable of responding to 5-minute dispatch signals. The non-dispatchable resources include generating plants that must be run for longer time periods, such as nuclear plants, as well as imports into the CAISO control area. These imports follow scheduling procedures set for the WECC as a whole, and must conform to fixed hourly schedules for exchanging power between control areas. Although imports are eligible to bid into the CAISO market for dispatch in real time, they must do so on an hourly basis and cannot be varied in the real time dispatch.

The CAISO is still evaluating the current implementation of real time dispatch, the RTMA, but notes two changes from the previous economic dispatch.¹³ First, prices have become more volatile and the fluctuation of the dispatch has increased. This result is consistent with the change in the design of the dispatch, which was intended to promote more frequent balancing of generation and load and produce market prices that more closely mirrored that balance. Second, RTMA has improved the handling of “start up” problems, including improved pricing of import/export bids. Coordination of the balance of hourly exports/imports and 5-minute generation dispatch continues to be a challenge, however, particularly when load is rapidly fluctuating.

C. Southwest and the Rockies

Although the Southwest and Rockies are separate areas, they have a single reliability coordinator, located at the WECC Rocky Mountain/Desert Southwest Reliability Center (RDRC) in Colorado. Both areas rely principally on thermal resources, but face somewhat different issues in performing economic dispatch. The Southwest has a larger amount of hydropower capacity in the generation mix, and has a significantly greater

¹² Based on a summer peak load of 141,100 in 2004, *WECC, 2005 Information Summary*, p. 2.

¹³ *Assessment of Economic Dispatch Practices at the CAISO*, initial Meeting of the West Joint Board on Economic Dispatch, November 13, 2005, p. 18.

level of trade with California.

Natural gas is the largest single source of generation in the Southwest, followed by coal and nuclear. Hydropower also plays a significant role, with slightly over ten percent of the total area capacity. Dispatch throughout the area is by individual utilities that perform unit commitment and economic dispatch of the own resources, supplemented by resources controlled by contract and purchases from the spot market. Generally, the large base load plants are located near fuel sources that are remote, and in some cases hundreds of miles away from the load centers. These base load units may be jointly owned, each with its own dedicated capacity that needs to be dispatched. Consequently, the availability of transmission facilities is a factor that must be taken into account in the economic dispatch. This general pattern of utility dispatch is followed by large investor owned utilities such as Arizona Public Service, large projects such as the Salt River Project, and smaller cooperatives and public power entities. Thus the Southwest dispatch is similar to the basic model described in the Section II, and does not have the extensive procedures needed to coordinate the dispatch of the hydropower resources of the Northwest, nor has it adopted the centralized dispatch procedures used in the CAISO. Active spot markets exist at the Palo Verde, Four Corners and Mead hubs, providing a basis for price discovery in the Southwest and points of reference for including wholesale purchases in the economic dispatch.¹⁴

El Paso Electric (EPE), the only Texas electric provider in the Western Interconnection, is a small part of that grid, and is in a particularly constrained area to the extent that, in the short run, moving to a broader regional dispatch may have little impact for EPE. However, Texas believes there are longer-term regional and national benefits that could be obtained from a more coordinated dispatch through more efficient fuel use and the development of the competitive wholesale electricity market in the western region.¹⁵

Like the Southwest, the Rockies generation resources are largely thermal, with coal being the largest generation resource, followed by natural gas, and dispatch follows the single utility approach, together with use of resources under contract and spot market purchases. The utilities serving this area utilize WECC's services in coordinating and promoting electric system reliability on the Western Interconnection. WECC supports efficient competitive power markets, open and non-discriminatory transmission access among members (including, e.g., BPA, CAISO, LADWP, and many privately and cooperatively held utilities serving throughout the West), provides a forum for resolving transmission access disputes, and fosters coordination of the operating and planning activities of its members.

¹⁴ See, DOE survey comments of APS, Salt River Project and Arizona Electric Power Cooperative on the use of wholesale spot purchases in the dispatch.

¹⁵ *Texas Perspective on Security Constrained Economic Dispatch*, p1.

D. Western Systems Power Pool

Trading between utilities and between sub-regions of the West improves the dispatch of resources. Such trade is enhanced by the Western Systems Power Pool (WSPP). As discussed above, there is a long history in the West of both seasonal (north-south) and resources-to-load (east-west) power movement. For these reasons, there has been an active wholesale electricity market in the West for decades. This market became more formalized in 1987, when FERC approved the WSPP. The WSPP has provided a platform for short-term transactions throughout the Western Interconnection for economy energy, unit commitment, and firm sales or exchange services. With over 220 WSPP members (virtually all market participants), the WSPP agreements are the most widely used standardized power sales contracts in the electric industry.

As a result, this readily available platform for day-ahead and real-time transactions adds an important dimension to SCED in the West. (Even entities within the CAISO, many of which are WSPP members, can use the WSPP agreements to import power if the transmission capability exists.) It allows Western electricity market participants to use risk management strategies more effectively in order to meet their load service obligations at the lowest cost practicable and in a reliable manner. These wholesale activities provide enhanced operational flexibility, particularly when water available for hydroelectric generation is subnormal, unplanned generation or transmission outages occur or transmission constraints exist. They also provide economic flexibility based on how wholesale prices compare with marginal generation costs. Thus, the ability to trade electricity on a West-wide basis greatly influences the process of economic dispatch.

This has led to the development of numerous robust wholesale trading hubs in the Western Interconnection, such as Mid-Columbia, Palo Verde, California-Oregon Border, North Path 15, and South Path 15, where numerous wholesale electricity purchases and sales occur on a daily basis. Sales volumes and prices at these hubs are reported on a voluntary basis to ICE (IntercontinentalExchange Inc.), Dow Jones, and other reporting services, aggregated by hub, and made public daily. Sales by jurisdictional utilities are also reported to FERC in Electronic Quarterly Reports.

IV. Issues and Recommendations

This section describes the issues considered by the Joint Board, and identifies any recommended approaches for addressing these issues..

The Joint Board makes two general observations regarding any approach to issues relating to SCED. First, Joint Board members generally believed that there should not be a “one size fits all” approach to the use of SCED. Differences among the areas in the west, and often differences within each area, are too large to warrant recommending a

single form of SCED for all areas or utilities. Second, the focus of changes from current practices should be at the state or local level. Regional or subregional changes should be based on collaborative efforts among utilities, other market participants and states, rather than on legislative or regulatory initiatives at the federal level.

Recommendations from the DOE report to Congress on the value of economic dispatch are discussed at the end of this section.

A. Observations

Introduction

A number of general issues have been raised about the nature of economic dispatch, its scope and uses, and implications for affordable and reliable service to electricity consumers. These general issues include:

- Relative importance of hourly dispatch costs
- Least cost production may not be lowest cost for the ratepayer
- The broad choice between cost-based and bid-based dispatch

Relative importance of economic dispatch.

Some board members and market participants expressed the desire to put the implications of economic dispatch in an overall cost perspective. In terms of total overall cost, economic dispatch, when framed in terms of daily and hourly dispatch, was felt to be relatively unimportant compared to long term investment in generation and transmission.¹⁶

Least cost production may not be lowest cost for the ratepayer.¹⁷

This issue was raised by several board members, in reference to environmental costs, the nonpower issues of hydropower scheduling, and other considerations. The concern was that many factors are considered in the unit dispatch decision that cannot be easily translated into short term monetary terms, so that exclusive emphasis on minimizing daily or hourly production costs could prove to be more expensive to the ratepayer in the long run.

¹⁶ Commissioner Schneider, Transcript of first West Joint Board meeting (Tr.) at 116.

¹⁷ Commissioner Beyer, Tr. at 114.

Choice of cost based or bid based dispatch.

This issue focused on the idea that economic dispatch often arose in the context of choice between two different systems of dispatch. The cost-based system referred to the basic single utility dispatch where a utility dispatched its own units based on its own generation costs and other factors, and was compared to a system with a separate grid operator that dispatched generation resources based on bids to supply power and then set a market price for the power based on the bids. Each overall approach gave rise to different sets of specific issues regarding the factors to consider for SCED. One board member noted the existence of these different approaches, and proposed that the board not recommend a single approach to this issue.¹⁸

B. Specific Dispatch Issues

Introduction

The specific dispatch issues raised varied by subregion, with different issues raised in each of the areas of the west, and by market segment within regions, and with different issues raised by utilities, independent power producers, grid operators and state regulators. These specific issues are listed below and discussed in the remainder of this section.

- Independence of dispatcher
- Utility dispatch of third party power through contracts
- Transparency of dispatch information and processes
- Consolidation of control areas
- Regional scope benefits
- Import/export schedule changes within an hour

Independence of dispatcher.

A representative from the independent power producers (IPPs) recommended that some type of independent transmission dispatch was needed so that independent power producer resources could be fully integrated in the hour-to-hour operation of the dispatch.¹⁹ In discussion, the IPP representative stated that dispatcher independence was

¹⁸ Commissioner Campbell, Tr. at 110

¹⁹ Mr. Kahn, Tr. at 91.

a prerequisite for merit order dispatch.²⁰

Board discussion:

There are three dispatch models employed in the Western Interconnection: [i] the California Independent System Operator (CAISO), [ii] individual utilities performing economic dispatch within their control areas, and [iii] public and private utilities cooperating to dispatch the Northwest's multi-owner hydroelectric system.²¹ All three models may be assisted by the WSPP. Faced with a variety of different operating scenarios and the issues they raise, including those concerned with the performance of independent operators, states should be allowed to deal with these issues themselves. Texas states that "having an independent grid coordinator with access to comprehensive regional information can significantly enhance reliability and market operations."²² However, there is little enthusiasm among other Joint Board Members for creating new independent dispatchers where the current system is functioning properly; and "joining or not joining a regional dispatch entity should be up to each utility and the negotiation with their regulatory body."²³ Decisions on dispatcher independence should be flexible and responsive to the needs of the state²⁴ Independent entities should not be created for their own sake:

Where utilities perform dispatch functions and do so fairly and efficiently, they should not be supplanted with an independent dispatcher simply for the sake of having one. Utilities operating in such a manner should be involved with the development of independent dispatching entities.²⁵

In addition to a general caution regarding significant changes to existing dispatch practices, two recommendations were put forward: (1) keep any structural changes flexible and sensitive to the needs of the states; and (2) make changes voluntary wherever possible.²⁶ Several board members cited this issue in their summary remarks.²⁷ In addressing the question, regulators should remember that both public and private entities serve load in many areas. All have duties to serve the public but all do not have the same

²⁰ Mr. Kahn, in response to a question from Commissioner Grueneich concerning whether a utility would always favor its own generation, Tr. at 94.

²¹ Commissioner Campbell, Tr. 2, p. 38; and Commissioner Smith, Tr. 2., p. 38.

²² *Texas Perspective on Security Constrained Economic Dispatch*, p2.

²³ Mr. Brown, Tr. 2., p37.

²⁴ Commissioner Sidran, Mr. Brown and Commissioner Grueneich, Tr. 2, pp. 36-39.

²⁵ *Wyoming Discussion Points*, February 3, 2006, p. 1.

²⁶ Ms. Edwards, Tr. at 73.

²⁷ Commissioner Greuneich, Tr. at 111; Commissioner Beyer, Tr. at 115.

level or type of regulatory oversight.²⁸

Recommendation:

We recommend that independent dispatch entities not be created for their own sake. We do not recommend further analysis at this time. If any further analysis is later deemed warranted, it must include an investigation of the potential benefit to consumers. If further work appears justified on the facts, the affected states and relevant utilities should determine the nature of the dispatching entity to be considered. Where public, cooperative and privately owned entities serve the market under consideration, their participation should be encouraged.

Utility dispatch of third party power through contracts.

This issue was cited by both utilities and non-utilities, with utilities sometimes arguing that it was difficult to obtain sufficient performance and reliability from third party contracts. One utility stated the primary difficulty with incorporating non-utility generation in their dispatch was their “inability to complete alternative actions in a swift and economic manner.”²⁹ Independent power producers stated the opposite position, arguing that their generation was flexible and capable of being very responsive, but that they were often denied the ability to dispatch power by utility generation owners who controlled the dispatch, particularly in the case of hourly dispatch and ancillary services.³⁰

Board discussion:

This issue describes the ongoing tension among IPPs and incumbent utilities on the subject of IPP integration; and the independent producers should play a constructive and full role in the development of a system capable of accommodating them. IPP integration should be approached as part of a cooperative effort, overseen on a subregional level by appropriate entities or on an interconnection-wide level by WECC through its committee process. Entities should carefully consider the potential reliability and dispatchability impact of the IPP on the Western Interconnection or relevant portions thereof and should make sure that the IPP bears its fair share of the costs of integration with the system, including the up-front cost of creating any independent dispatch capability to accommodate their participation. Thus, consideration of “merit order” dispatch should be done in the context of an overall cooperative effort and not as a goal in and of itself. The ultimate end of the effort is to serve the consumers better and more efficiently, and consideration of when to dispatch will likely have less monetary impact on consumers

²⁸ Commissioner Sidran, Tr. 2, p. 40.

²⁹ Portland General Electric response to DOE survey, p. 2.

³⁰ Mr. Kahn, Tr. at 88.

than will wise choices of what resources to build.³¹

Further progress will require basic contract commitments by IPPs regarding dispatchability and other issues. EPSA and EEI proposals to develop standard contract terms should be encouraged.³² In summary, Commissioner Kelly cited the following member's observation as the consensus of the Joint Board that it should:

“Encourage contractual commitments by independent producers to provide energy in a manner consistent with the utility's dispatch, but do not require utilities to purchase nonutility power.”³³

Recommendation:

We encourage, but do not wish to duplicate, the efforts of EPSA and EEI in developing standard contractual language addressing dispatchability and other issues. The Joint Board recommends the use of contractual commitments by IPPs to provide capacity, energy and ancillary services in a manner consistent with the relevant LSE's dispatch needs. Integrating IPPs into the dispatch in the Western Interconnection should be overseen by WECC on an interconnection-wide basis, or subregionally by an appropriate entity.

Transparency of dispatch information and processes.

One of the benefits cited for an independent entity dispatching all resources in a region was the ability to provide a transparent process for the dispatch. One utility representative argued that full value economic dispatch would not be fully realized without this transparency.³⁴ Without the independence condition, sharing sensitive real-time information between a utility transmission provider and third parties can be viewed as an impediment to dispatching economically.³⁵

Board discussion:

Transparency of information and process can enhance the dispatch function, but the desire to promote transparency should not drive the decision as to whether or not an independent dispatch entity is needed. Transparency is not an end in itself. It can further some of the goals of economic dispatch, but should not serve as a rationale for creating

³¹ See, *Wyoming Discussion Points*, February 3, 2006, pp. 2-4.

³² See discussion of the Second DOE Recommendation in section C of this document.

³³ Tr. 2, p. 41; and Attachment C to Supplemental Notice of Second West Joint Board Meeting in FERC Docket No. AD05-13-000, p. 1.

³⁴ Mr. Larson, Tr. at 49.

³⁵ Discussion between Commissioner Smith and Mr. Larson, Tr. at 53 and 54.

an independent entity to achieve transparency. Furthermore, one board member observed that too much market knowledge can potentially foster collusion which can do damage to the market ostensibly being helped.³⁶ Transparency of information can be a benefit to a region, but that benefit is not in itself sufficient to support a mandate for regional economic dispatch.³⁷

In a related observation, the Department of Energy suggested that there should be further study of the “impact of the accuracy of load forecasting and quality load forecasting on the results of economic dispatch.” If the quality of forecasted information is low, the resulting dispatch may be wasteful. DOE suggested the study look at the costs of suboptimal forecasting and “ways to improve the quality of forecasting to improve economic dispatch.”³⁸

Recommendation:

Achieving transparency is not sufficient by itself to justify the creation of an independent dispatch entity. We recommend that the Department of Energy study ways to improve the accuracy of forecasting to improve economic dispatch and identify savings that could be achieved thereby.

Consolidation of control areas in a region.

The current single-utility dispatch means that each utility first determines a dispatch for its own area with only limited knowledge of conditions in other areas. In the Western Interconnection, WECC provides important real time information on the status of the grid which assists dispatchers. However, coordination among control areas may sometimes be based on limited information on generation availability in other areas and constraints on transmission available for imports and exports between control areas, when compared to the information available within each control area. The larger the number of areas, the greater the potential benefit of consolidating control areas, in principle, arising from better information available to the dispatchers and better control over generation and transmission resources. Some presenters recommended that control areas be consolidated, citing the large number in an area like the Northwest.³⁹ Others argued that there were potential benefits to SCED from consolidation, without taking a position on whether the benefits of consolidation would exceed the costs.⁴⁰ Texas cited the ERCOT example of combining ten control areas into one as providing evidence of significant

³⁶ Commissioner Schneider, Tr. 2, p. 44.

³⁷ Commissioner Sidran, Tr. 2, p. 42.

³⁸ Ms. Silverstein, Tr. 2, p. 62.

³⁹ Mr. Kahn, Tr. at 89.

⁴⁰ BPA in comments submitted in the docket.

benefits from control area consolidation and regional dispatch.⁴¹

Board discussion

Consolidation of control areas should be approached rationally rather than making consolidation an aim in itself. Single utilities do not dispatch in an informational vacuum, but frequently are in contact with relevant control centers and entities throughout the Western Interconnection. Very large control areas encounter problems in dealing with 15-minute import/export exchange to ameliorate problems of scheduling on the hour. However, it is also true that larger control areas can be a positive development if the integration of smaller control areas makes operational sense. This is especially true for wind resources which can benefit from being part of larger and hence more diverse control areas. The focus should be on the technological advisability of consolidation and not on simply reaching the goal of larger and larger control areas.⁴² The geography of the West has already helped to create relatively large control areas, which is not always the case in other parts of the nation. We therefore must be careful to examine the costs and usefulness of further consolidation.⁴³ WECC's three reliability centers which can see the entire Western Interconnection should be an integral part of the analysis of control centers. WECC is now studying its reliability centers to determine both the number of centers needed in the future and what tools are required to see the whole of the Western Interconnection at once and to issue reliability directives. Commissioner Smith cautioned against creating new single-generator control areas.⁴⁴

Increasing the size of the dispatch region, even without consolidating regions into a single control area, can lead, in principle, to a lower cost dispatch through inclusion of more generation and transmission resources. However, there appeared to be no consensus on whether such regional benefits exist in practice. Some cited regional benefit studies that concluded there were positive net benefits; for example, the representative from the Independent Power Producers cited a recent study for Grid West as demonstrating benefits.⁴⁵ One utility representative stated that there were potential benefits from regionalization, without citing a specific study. However, at least some board members felt the current system of utility dispatch coupled with spot and short term market purchases worked efficiently. One board member cited the adage, "If it ain't broke, don't fix it."⁴⁶

⁴¹ *Texas Perspective on Security Constrained Economic Dispatch*, p1.

⁴² Commissioner Campbell, Tr. 2, pp. 45-46; and his comment approving *Wyoming Discussion Points*, February 3, 2006, p. 3.

⁴³ Commissioners King and Johnson, Tr. 2, pp. 47.

⁴⁴ Commissioner Smith, Tr. 2, pp. 47-49.

⁴⁵ Mr. Kahn, Tr. at 90.

⁴⁶ Commissioner Baca, Tr. at 119.

The west should carefully examine the usefulness of creating larger dispatch regions on an individual basis. Participation by major stakeholders should be assured before meaningful consolidation can take place. The west should draw on the well developed grid management experience of institutions such as WECC, and on the wholesale market facilitation and coordination experience of entities such as WSPP, to assist in deciding whether or not to form larger dispatch -- or control -- areas. Case-by-case examination would better fit with the diversity encountered in the Western Interconnection than would a blanket consolidation mandate.⁴⁷

Recommendation:

We recommend that the states, individually or jointly, consider further consolidation of control areas. Further studies should take into account [i] the value of larger control areas for renewables such as wind, and [ii] solving the problems of large control areas in scheduling within the hour. Any consolidation decision should be based on the needs of consumers and the region's economy for reliable and affordable power; and we recommend that consolidation not be thought of as a goal in itself. Enlargements should be approached on a case-by-case basis with the assistance of WECC and possibly the WSPP.

Import/export schedule changes within an hour.

The CAISO identified large hourly schedule changes as a problem for their dispatch. The source of this problem is that schedules between control areas change at the beginning of each hour and remain constant for the hour. Because the CAISO often has large amounts of imported power at the same time that it has large changes in load over the hour, it becomes difficult to accommodate these large blocks of hourly imports while following a volatile load.⁴⁸ To address this issue, CAISO recommended spreading the changes out over the hour to decrease the magnitude of each change.⁴⁹ Scheduling could still occur on an hourly basis, but each hourly schedule could increase or decrease on a less than one hour basis, for example, on 15 minute intervals. Because scheduling imports and exports between control areas in the west follows a standard protocol, developing the ability to provide schedule varying on 15 minute intervals would require coordinated development of such a change throughout the west.⁵⁰ One board member cited this recommendation positively, but there was no further comment from other board members at the initial meeting.⁵¹

⁴⁷ Commissioner Lewis, Tr. 2, p. 50.

⁴⁸ Mr. Rothleder, Tr. at 38.

⁴⁹ Mr. Rothleder, Tr. at 41.

⁵⁰ Mr. Rothleder, Tr. at 39.

⁵¹ Commissioner Campbell, Tr. at 110.

Board discussion:

Although this is, at this time, a situation most focused on California and the CAISO as it confronts loads which are more volatile than imports over the hour, the Board in general supported the concept.⁵² Oregon's experience shows that hourly scheduling of interchanges between utilities is complicated by relatively slow ramp rates which can cause utilities to experience imbalances. Allowing for ramp rate changes, e.g., 10 minutes before and after the hour, could significantly reduce these imbalances. The Board accepted this addition as an important consideration for further work on the topic.⁵³

Recommendation:

We recommend that the WECC develop a standard west-wide protocol to address the need for scheduling before, during and after the top of the hour.

Some practical limitations on economic dispatch.

The heavy and increasing reliance on natural gas as a generator fuel must be included in future studies of economic dispatch. Recognizing that it is subject to substantial price volatility, the ideal might be to dispatch the most efficient natural gas plants to make the best possible use of our natural gas resources. The study of the challenges inherent in the use of natural gas may begin with the distinction between economic dispatch and efficient dispatch. The United States Department of Energy has described the differences between these concepts:

In a recent hearing of the Senate Energy and Natural Resources Committee*, there was great interest in determining whether economic dispatch practices could or should be modified to ensure the most efficient use of scarce natural gas in gas-fired generation units. "Economic dispatch," as noted above, is an optimization process crafted to meet electricity demand at the lowest cost, given the operational constraints of the generation fleet and the transmission system. Although economic dispatch will *usually* run higher efficiency gas-fired units before lower efficiency units, that is not always the case, for a number of possible reasons. "Efficient dispatch" would presumably seek to modify the practice of economic dispatch to ensure that more efficient gas-fired units are *always* used before less efficient units.

Despite DOE's interest in ensuring the efficient use of natural gas for electricity generation and other purposes, it remains skeptical of the merits of "efficient dispatch," for several reasons:

⁵² Commissioners Grueneich and Kelly, Tr. 2, pp. 51-52.

⁵³ Mr. Brown and Commissioner Kelly, Tr. 2, pp. 52-53

- The fundamental purpose of economic dispatch is to reduce consumers' electricity costs. "Efficient dispatch" would take the dispatch process off this path and increase consumers electricity costs – for benefits that may not be large enough to offset these additional costs.
- Economic dispatch is at best a complex process, and modifications to it must be made with care in order to minimize unanticipated consequences. Modifying it to achieve short-term non-economic policy objectives should be considered only as a last resort.
- A better alternative would be to examine the practice of economic dispatch itself to determine whether modifications are needed to better achieve its traditional objectives – which could by itself lead to more efficient use of natural gas. A review of this kind could be pursued through the regional joint FERC-State boards created by EPAct in Sec. 1298.⁵⁴

* Senate Committee on Energy and Natural Resources, Full Committee Hearing – Hurricane Recovery Efforts, October 27, 2005

Board discussion:

SCED is defined above in Section II of this report sufficiently broadly to include more localized reliability concerns. Therefore, the definition of SCED should not later be so narrowly construed that it makes it impractical or too costly to incorporate such local reliability and other considerations in regional, subregional or state analyses.

California observed, as a practical matter, that it would probably have to keep older and less efficient natural gas-fired plants in operation to deal with more localized issues of reliability and system congestion. This goes to the heart of how we define economic dispatch in the future and means that there must be practical rather than only theoretical assessments of system capabilities and costs. Commissioner Grueneich of California observed that, to accommodate these considerations, either [i] the definition of economic dispatch should be broadened to take such reliability-related issues into account, or [ii] the inquiry should be taken beyond economic dispatch to allow these issues to be considered.

Similarly, California recommends incorporation of renewable generation in the economic dispatch process. In California, economic dispatch also means incorporating the State's policy of encouraging the development of renewable energy sources and the preferred resource loading order. California's "Energy Action Plan II" includes a loading order that identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs followed by renewable generation, combined heat and

⁵⁴ *The Value of Economic Dispatch: A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005, p. 11. Text of report found at <http://www.electricity.doe.gov/document/value.pdf>

power and distributed generation, and traditional fossil resources. Some other states across the country have also adopted renewable portfolio standards in many ways similar to California's but with different regional goals which reflect public policy in those individual states.⁵⁵

Even with overall goals of trying to address natural gas prices and of implementing direct economic dispatch, the local cost and reliability issues will vary to such an extent that each particular situation should be examined closely -- "on a very decentralized basis."⁵⁶

Better service to the people is the primary goal of this inquiry. Issues of reliability and system congestion can have region-wide implications, but they also have a strong local dimension which can keep purely theoretical economic dispatch from being the best or most realistic solution. The best way to deal with such challenges is to make analyses on a case-by-case basis, not ignoring economic dispatch but recognizing that it is not an end in itself and that it should not be promoted with disregard for its local effects.

Recommendation:

We recommend that the definition of security constrained economic dispatch be broadened to include other public policies, values and physical and operational constraints as well as costs.

C. Recommendations from the DOE Report to Congress

The DOE Report to Congress, *The Value of Economic Dispatch*, contains three recommendations that are relevant to the security constrained economic dispatch issues that the Joint Board has been considering. These three recommendations are described below.

First DOE Recommendation: review dispatch practices

FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some IOUs, to determine how they conduct Economic Dispatch.⁵⁷ These reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, in terms of procurement, unit commitment and real-time dispatch. The reviews should distinguish entity-specific and regional business practices

⁵⁵ Commissioner Grueneich, Tr. 2, pp. 11-13.

⁵⁶ Commissioner Grueneich, Tr. 2, pp. 57-58.

⁵⁷ *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005, p. 52.

from regulatory, environmental and reliability-driven constraints. These reviews could assist FERC and the states in rethinking existing rules or crafting new rules and procedures to allow IPPs and other resources to compete effectively and serve load.

Board discussion:

The study recommended here was generally seen as being at odds with the general consensus of the Joint Board that economic dispatch has to be a flexible concept, capable of adapting to the varying needs of different states and subregions in the Western Interconnection. The study would take us deeply into variables and deviations from “pure” economic dispatch without providing much value.⁵⁸ On the other hand, California, with its substantial unregulated municipal utility presence, could benefit from a better understanding of how these entities make economic dispatch decisions, although jurisdictional and funding issues probably make the issue unripe at this time.⁵⁹ The new rules presupposed in this recommendation may be incorrectly assumed necessary. The recommendation is also at odds with the complexity of economic dispatch issues in the Western Interconnection.⁶⁰ The Joint Board generally agreed that this recommendation should not be pursued. However, Texas believes that there are potentially significant benefits from SCED that warrant study and disagrees with the recommendation not to pursue further study at this time.⁶¹

Recommendation:

The Board recommends that this study not be pursued. Such a study would take us deeply into variables and deviations from “pure” economic dispatch without providing much value. It is at odds with our fundamental conclusion that economic dispatch must remain a flexible concept.

Second DOE Recommendation: standardize dispatch contract terms

FERC and DOE should explore EPSA and EEI proposals for more standard contract terms and encourage stakeholders to undertake these efforts.⁶² Specifically, the EEI has proposed that [i] IPPs should commit to provide energy at specified prices for specified times to meet unit commitment schedules, and [ii] there should be contractual performance standards with penalties for failure to deliver. EPSA proposed developing technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms for routine transactions.

⁵⁸ Commissioner Sidran, Tr. 2, pp. 23-24.

⁵⁹ Commissioner Grueneich, Tr. 2, pp. 24-25.

⁶⁰ Commissioner Smith, Tr. 2, pp. 25-26; Commissioner Schneider, Tr. 2, p. 26.

⁶¹ Commissioner Smitherman, Tr. at 126-28.

⁶² *DOE Report* at p. 51.

Board discussion:

A high level of cooperation already exists in the electric industry and among the non-utility generators regarding contracts.⁶³ Existing initiatives should be the vehicle for crafting standard language of the kind envisioned in the Recommendation and therefore it should be pursued by industry and the IPPs rather than through duplication by the Joint Board or the federal government. The Recommendation rightly recognizes the value of communication among stakeholders to refine their relationships. The Joint Board recognizes the valuable and ongoing work of the North American Energy Standards Board (NAESB) to promote well crafted standardized contracts to encourage efficiency in the electric and natural gas marketplaces.⁶⁴ We also encourage EPSA and EEI to go forward with standard contract language proposals. We believe that these existing initiatives should be monitored and encouraged but not duplicated.⁶⁵ Regional differences in some cases may be so pronounced that standard contracts should take them into account. Thus, a Western Interconnection contract might of necessity differ from one employed in the East. We note the difference between on-peak products in the East and the West.⁶⁶ Wyoming's comment on this subject summarizes the Joint Board's response to this recommendation:⁶⁷

We think this recommendation should be pursued on a regional basis rather than on a national basis. The regional variances in grid operating parameters throughout the Western Interconnection make a strong case for allowing development to go forward on a regional basis. This does not mean that standardized terms are per se a bad idea or that federal resources such as those of the DOE should not play an important collaborative role.

Recommendation:

We recommend that the standardization of dispatch contract terms be pursued on a regional basis rather than on a national basis. The regional variances in transmission grid operating parameters throughout the Western Interconnection make a strong case for allowing development to go forward on a regional basis.

⁶³ Mr. Hinckley, Tr. 2, p. 28.

⁶⁴ Commissioner Sidran, Tr. 2, p.32

⁶⁵ Commissioner Smith, Tr. 2, pp. 31-32.

⁶⁶ Commissioner Campbell, Tr. 2, p. 31; and New Mexico Comments of February 13, 2006, p. 3.

⁶⁷ Commissioner Lewis, Tr. 2, pp. 28-29; and Commissioner Campbell, Tr. 2, p. 31; and *Wyoming Discussion Points*, February 3, 2006, p. 4.

Third DOE Recommendation: review dispatch tools

Current economic dispatch technology tools deserve scrutiny.⁶⁸ These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions.

Recommendation:

We recommend the development and refinement of technological tools to make the best use of existing and proposed facilities.⁶⁹

⁶⁸ DOE Report at p. 53.

⁶⁹ Commissioners Smith, Grueneich, and Mr. Hinckley, Tr. 2, pp. 33-34.