95 FERC ¶ 61,225
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Curt Hébert, Jr., Chairman;
William L. Massey, and Linda Breathitt.

Removing Obstacles To Increased Electric Generation And Natural Gas Supply In The Western United States	Docket Nos. EL01-47-000 and EL01-47-001

FURTHER ORDER ON REMOVING OBSTACLES TO INCREASED ENERGY SUPPLY AND REDUCED DEMAND IN THE WESTERN UNITED STATES AND DISMISSING PETITION FOR REHEARING

(Issued May 16, 2001)

Introduction

On March 14, 2001, in response to the severe electric energy shortages facing California and other areas in the West,[1] the Commission announced certain actions it was taking within its regulatory authorities under the Federal Power Act, the Natural Gas Act, the Natural Gas Policy Act, the Public Utility Regulatory Policies Act and the Interstate Commerce Act to help increase electric generation supply and delivery in the Western United States, to facilitate demand responsiveness, and to protect consumers from supply disruptions.[2] The Commission implemented some measures immediately and sought comments on other measures that might help maximize supply, delivery, and demand reduction. This order follows up on the March 14 Order based upon consideration of the comments received.

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[1]As we stated in the March 14 Order, we are concerned here with what actions may affect electricity supply and demand in the Unites States portion of the Western Interconnection, which is the area encompassed within the United States portion of the Western Systems Coordinating Council (WSCC).

[2]Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States and Requesting Comments on Further Actions to Increase Energy Supply and Decrease Energy Consumption, 94 FERC ¶ 61,272 (2001) (March 14 Order).

In the March 14 Order, the Commission examined both electric supply-side and demand-side actions that could be taken, as well as how to best assure the availability of natural gas for electric power production. The Commission considered electric transmission constraints, generation inadequacy, demand-side response, the need to increase natural gas pipeline capacity where appropriate, possible hydroelectric generation improvements that could be made while protecting the environment, and whether innovative proposals could ensure an adequate flow of petroleum product into the California market for electric generation.

Among the actions the Commission took immediately were to request a list of grid enhancements that could be undertaken in the short term, extend certain waivers for Qualifying Facilities, waive certain notice and filing requirements for wholesale power sales from on-site generation at businesses, authorize the resale of load reductions at market-based rates, and request that hydroelectric licensees examine their projects for efficiency improvements. Among the proposals the Commission sought comment on were premiums on equity returns and accelerated depreciation for certain transmission investments, allowed revenue recovery for non-capital intensive expenditures that increase transmission capacity, allowed rolling in of certain interconnection costs for new supply, use of the interconnection authority of section 210(d) of the Federal Power Act (FPA), waiver of blanket certificate regulations to increase the dollar limits for automatic and prior-notice authorizations for natural gas facilities, offering blanket certificates for portable compressor stations, rate incentives to expedite construction of pipeline projects, and allowing greater operating flexibility at hydroelectric projects.

Pursuant to the March 14 Order, the Commission convened two conferences. The Commission staff held conferences in Portland, Oregon and Sacramento, California on April 9 and 10, 2001 with licensees and interested stakeholders to discuss methods for allowing increased generation at hydropower projects while ensuring environmental protection. On April 10, 2001, the Commission held a conference on Western Energy Issues in Boise, Idaho to discuss price volatility in the West and other Commission-related issues raised by the Governors of Western states.[3]

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[3]Two state representatives, who included one state commissioner from Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming attended the conference. Comments regarding the conference have been filed under Docket No. PL01-3-000.

In this Order, the Commission reiterates the urgent need to do what it can to alleviate the ongoing energy situation facing the West and generally affirms its approach in providing incentives and removing obstacles to increased energy supply in the West.[4] As described more fully below, this order reaffirms Commission actions implemented by the March 14 Order, and implements additional actions. Unless specifically noted below, these actions are in effect as of the date of this order and, consistent with the timeline established for the recent Commission monitoring and mitigation order,[5] will expire on April 30, 2002. The Commission:

- Allows premiums on equity returns, and accelerated depreciation, for projects that increase electric energy transmission capacity in the short term, with a uniform baseline cost of equity of 11.5%, specifically:

  - a cost-based rate reflecting a 200 basis point premium and a 10-year depreciable life for projects that increase transmission capacity at present constraints and can be in service by July 1, 2001.

  - a cost-based rate reflecting a 150 basis point premium and a 10-year depreciable life for projects that increase transmission capacity at present constraints and can be in service by November 1, 2001.

  - a cost-based rate reflecting a 100 basis point premium and 15-year depreciable life for system upgrades that involve new rights of way and can be in service by November 1, 2002.

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[4]The National Rural Electric Association (NRECA) and the American Public Power Association (APPA) added a "petition for rehearing" to their comments on the March 14 Order. Most of their comments address non-final action in the March 14 Order that is not subject to rehearing. The one comment that addressed an action immediately implemented concerns an issue that is clarified in the discussion on selling demand reduction herein. Accordingly, the petition for rehearing is dismissed.

[5]See Order Establishing Prospective Mitigation and Monitoring Plan for the California Wholesale Electric Markets and Establishing an Investigation of Public Utility Rates in Wholesale Western Energy Markets, 95 FERC ¶ 61,115 (2001)(establishing that the monitoring and mitigation plan adopted will terminate not later than one year from the date of the order issued on April 26, 2001) (April 26 Order).

  - a cost-based rate reflecting a 150 basis point premium for new interconnection facilities required for new entrants if in service by November 1, 2001, and a 100 basis point premium if in service by November 1, 2002.

- Allows revenue recovery for non-capital intensive expenditures made to increase transmission capacity on constrained interfaces.

- Allows limited section 205 filings under the Federal Power Act to implement the incentives adopted herein.

- Allows rolling in of interconnection and upgrade costs associated with new supply, rather than directly assigning such costs to the generator for projects that are in service by November 1, 2002.

- Effective March 14, 2001,[6] extends and broadens the temporary waivers of operating and efficiency standards, and fuel use requirements, for qualifying facilities.

- Effective March 14, 2001, waives prior notice requirements and grants authorization of market-based rates for wholesale power sales from generation used primarily for back-up and self generation and located at businesses within the WSCC.

- Effective March 14, 2001, authorizes wholesale customers and retail customers (where permitted under state rules) who reduce consumption to resell their load reduction at wholesale at market-based rates.

- Effective March 14, 2001, waives the prior notice requirements for wholesale contract modifications to facilitate demand-side management.

- Effective March 14, 2001, where there are cost-based wholesale rates in effect subject to a formula, the Commission will permit DSM costs to be treated consistently with other types of incremental and out-of-pocket costs.

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[6]Pursuant to the March 14 Order, as noted above, certain Commission actions took effect on March 14, 2001. 94 FERC ¶ 61,272 at 61,968.

- Temporarily waives blanket certificate regulations to increase the dollar limitations for natural gas facilities under automatic authorization to $10 million and for prior notice authorizations to $30 million.

- Temporarily waives blanket certificate regulations to allow construction of mainline facilities, including temporary compression and facilities that alter mainline capacity.

- Allows pipelines to roll-in costs of facilities constructed under waived blanket certificate regulations.

- Will grant expeditious consideration for proposals for greater operating flexibility at licensed hydroelectric projects to increase generation while protecting environmental resources.

General Comments

In response to the March 14 Order, the Commission received more than one hundred sets of comments and interventions from commenters who are listed in Attachment A. There is substantial agreement among commenters that the West currently faces a lack of adequate energy supply that will continue into the foreseeable future, which warrants the Commission's immediate and expeditious action.[7] While commenters generally agree that the Commission should take immediate action to address the energy situation in the West, they emphasize different Commission proposals as well as offer alternative proposals.[8] Some commenters caution the Commission to consider the long-term impact of the incentives on consumers and the environment, while

[7]Some commenters, however, object to the Commission's basic understanding and characterization of the Western energy crisis. The Public Utilities Commission of California (CPUC) states that the recent energy situation in California does not involve a capacity shortage, rather the unavailability of in-state supply. Northern California Power Agency (NCPA) claims that the Commission underestimates the crisis and asserts that building up the infrastructure of the Western grid may be more difficult than anticipated.

[8]For example, Edison Electric Institute (EEI) favors what it labels as the Commission's "holistic" approach to natural gas supply and hydroelectric resources and California Department of Water Resources (DWR) supports the Commission's efforts to remove impediments to demand response.

others offer alternative proposals such as conservation and the development of renewable technology.

There are two sets of general comments that we address up front. First, some commenters favor the extension of Commission incentives nationwide to address capacity problems and avert energy problems in other areas. While we are aware of the potential for capacity deficiencies in other areas of the nation, we believe the most urgent need is in the West, which is where we will focus these measures for now. Entities in other parts of the country may request application of these measures on a case-by-case basis.

A second set of general comments assert that the Commission's actions are insufficient to resolve the crisis due to the lack of adequate price mitigation, and call upon the Commission to ensure that wholesale prices would be lowered to just and reasonable levels. For example, Southern California Edison Company (SCE) requests that the Commission regulate rates on a cost of service basis while CPUC, Idaho Public Utilities Commission (IPUC), and Public Power Council (PPC) support a remedy under Section 206 of the FPA. Other commenters also express their support or opposition to the implementation of temporary price caps. The Commission has recently issued an order adopting a number of related measures, including price mitigation measures that are intended to help remedy dysfunctional electricity markets in the West. That docket, not this one, is the appropriate forum for such pricing issues.[9]

I. Electric Generation and Transmission

A. Electric Transmission Infrastructure

1. List of Grid Enhancements

In the March 14 Order, the Commission directed the California Independent System Operator (California ISO) and the transmission owners in the WSCC to prepare and file within 30 days of the date of the March 14 Order, a list of grid enhancement

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[9] See supra note 5, citing April 26 Order. The Commission also convened a conference on Western Energy Issues on April 10, 2001 in Boise, Idaho to discuss price volatility and other Commission-related issues recently identified by the Governors of Western states. Comments for this conference were filed under Docket No. PL01-3-000.

projects that would offer the greatest potential for improving grid capacity at present constraints within the shortest period of time.[10]

The proposed grid enhancements filed in response to the March 14 Order consist of such projects as new or upgraded transmission lines, circuit breakers, facility upgrades, and system upgrades, which are being implemented to increase import capability or capacity, mitigate line overloads and enhance transmission capability. The project completion dates for proposed grid enhancements range from May 1, 2001 to after November 1, 2002.[11] We appreciate the lists submitted, and we encourage transmission owners in the West to continue to seek and implement projects that can enhance capacity immediately.

Several comments accompanied the lists of grid enhancement projects that were filed, noting, for example that successful development of this infrastructure requires adequate return and regulatory certainty with respect to future cost recovery, and that the difficulty in siting acts as a significant restraint to increased transmission capacity in the West. The Commission recognizes the siting problems, but has no authority to address them. The Commission also recognizes the necessity for adequate returns for transmission projects, and is responding appropriately.

2. Equity Return Premiums and Accelerated Depreciation

In order to provide incentives for the construction of new or upgraded transmission capacity at the earliest date possible, the March 14 Order proposed to give transmission owners of projects that increase transmission capacity at present constraints a cost-based rate reflecting a 300 basis point premium on equity and a 10-year depreciable life if in service by July 1, 2001, and a 200 basis point premium and a 10-year depreciable life if in service by November 1, 2001. To provide certainty at the outset for transmission owners, the Commission proposed to use a uniform baseline cost of equity of 11.5% for all jurisdictional transmission providers in the WSCC in implementing the equity premium.

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[10] The Commission requested that the filing clearly describe each project, its impact on grid capability at present constraints, the status of certification if necessary, its cost and a definite completion date.

[11] EEI cautions the Commission not to hold entities that provide grid enhancement information under this proceeding responsible for their cost estimates. This information was requested for informational purposes and is not binding.

Second, for system upgrades that involve new rights of way, add significant transfer capability and can be in service by November 1, 2002, the Commission proposed to allow transmission owners a cost-based rate reflecting a 100 basis point premium and 15-year depreciable life. Third, the Commission proposed that facilities needed to interconnect new supply to the grid which go in service as required to accommodate the in-service date of the new entrant be afforded a cost-based rate which reflects a 200 basis point premium if in service by November 1, 2001 and a 100 basis point premium if in service by November 1, 2002.

Comments on Equity Return Premiums and Accelerated Depreciation

Comments regarding equity return premiums and accelerated depreciable lives fall into three groups. Some commenters support the Commission's proposal, often with slight modifications. EEI supports a substantial return on equity incentive across the board above a uniform baseline cost of equity equal to at least the Commission's proposed 11.5 percent provided for all jurisdictional transmission providers in the WSCC, or a current state-approved rate. Several commenters state that the time frame is too short to provide an incentive to construct and recommend that the incentive apply to those projects that are already underway.

Other commenters contend that the proposed incentives of higher returns on equity and shorter depreciation periods may not serve their intended purposes. Arizona Corporation Commission (ACC) believes that the incentives may increase transmission rates in certain areas which would cause greater seams pricing disparities for emerging RTOs to overcome. Independent Energy Producers (IEP) does not understand the feasibility of return on equity "bonuses" in California as long as a rate freeze exists. Some commenters allege that the Commission's proposal is unsupportable.

In addition, some commenters provide specific proposals, with several urging the Commission to include projects with long construction lead times. Other requests include extending the time frame to which the incentives apply or suggest that the Commission perform studies of the equity markets to determine if equity premiums will encourage construction. Metropolitan Water District of Southern California (Metropolitan Water) maintains that system upgrade costs should be allocated in accordance with cost causation principles. PacifiCorp urges the Commission to eliminate the condition that only system upgrades that involve new rights of way will be considered under the incentive proposal because many projects with long construction lead times not involving new rights of way would meaningfully increase transfer capability**.** Salt River Project (SRP) recommends requiring a request for transmission service to accompany a request for interconnection from generators before regulated utilities can plan transmission upgrades. Duke recommends offering premiums on return on equity rates to promote RTO development.[12]

Some commenters seek clarification from the Commission concerning its proposed rate of return incentives. InterGen requests that the Commission clarify the interrelationship between the proposed rolled-in pricing rate design and the rate of return incentives.[13] Xcel requests clarification of the Commission's qualification standard, or alternatively, requests the Commission accept all new transmission on new rights of way as eligible for equity return premiums. Several commenters request clarification regarding the application and approval process. A few commenters suggest expanding the contemplated deadlines or applying the incentives nationwide.

While supporting the Commission's proposal, some commenters express doubt regarding the resulting benefits from incentives. Transmission Agency of Northern California (TANC) cautions the Commission against irreparably harming the existing structure. NRECA and APPA, and the NCPA recommend careful analysis before implementing incentive measures that will raise transmission rates to consumers. Several commenters doubt that these incentives will do much good because there are existing obligations to build such facilities and there is a lack of sufficient credit and capital. Alternatively, Industrial Consumers[14] proposes third party bids for rights to build or upgrade transmission facilities.

American Superconductor Corporation (AMSC) believes incentives are needed for the immediate installation of grid enhancements in both the short and long-term and advocates third party investments in grid enhancement provided the third parties can benefit from the upgrade. SCE maintains that to make better use of the available transmission capacity, the Commission must immediately order the development of new procedures for the California ISO's use in administering the existing transmission

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[12] See infra note 49 (RTO development for the West is currently being addressed in other proceedings before the Commission). See also, Order No. 2000 which addresses rate design for RTOs.

[13] InterGen believes that the rolled-in rate will comprise a weighted average rate of return based on the vintages of capital assets of the utility.

[14] Electricity Consumers Resource Council, the American Iron and Steel Institute, the American Chemistry Council, and the American Forest and Paper Association.

contracts. Williams encourages the Commission to aggressively facilitate investment in the electric transmission grid.

Xcel Energy Incorporated (Xcel) promotes interconnections between WSCC and other North American regions. While Metropolitan Water supports the goal of reducing grid constraints if cost-effective, it doubts that incentives to expedite grid enhancements within the next two years will be cost-effective. Pinnacle West Companies (Pinnacle) requests clarification that incentives are available for projects that avoid future constraints as well as for projects that alleviate current ones. SCE recommends the development of consistent, long-term policy of providing full cost recovery to transmission owners if the Commission seeks to promote enhancements to the transmission infrastructure. Pacificorp states the short time frame limits the number of potential projects qualifying for premiums on equity returns.

Commission Response

The Commission finds that the proposed rate of return premiums fall into a zone of reasonableness because they will likely expedite increased grid capacity, and thus will help address the existing emergency in the Western states. The proposed rate of return premiums adopted herein will apply only to projects built under these incentives, and will not increase the rates of return for existing plant.

The Commission will give transmission owners of projects that increase transmission capacity at present constraints and can be in service by July 1, 2001, a cost-based rate reflecting a 200 basis point premium on equity and a 10-year depreciable life. Those that can be in service by November 1, 2001 will receive a cost-based rate reflecting a 150 basis point premium and a 10-year depreciable life. The Commission also adopts its recommended 11.5% as a uniform baseline cost of equity, which is the most recent allowance the Commission has approved for a western utility.[15]

With respect to system upgrades that involve new rights of way and add significant transfer capacity,[16] the transmission owners of any such projects that can be in service by November 1, 2002, will be permitted a cost-based rate reflecting a return on equity of 12.5% (a 100 basis point premium) and a 15-year depreciable life.

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[15] See Southern California Edison Company, 92 FERC ¶ 61,070 (2000).

[16] Significant transfer capacity is any new right of way that adds transfer capability or reduces congestion on the system.

The Commission also adopts its proposal that facilities needed to interconnect new supply to the grid which go in service as required to accommodate the in-service date of the new entrant will also be afforded a cost-based rate which reflects a return on equity of 13% (a 150 basis point premium) if in service by November 1, 2001 and 12.5% (a 100 basis point premium) if in service by November 1, 2002.

We are retaining the original deadlines for project completion necessary to receive these incentives because the whole purpose of these incentives is to spur immediate action in order to alleviate the severe shortage of capacity in California and other problems facing Western electric energy markets. In addition, the Commission affirms that it will consider pending projects, i.e., those now underway, for the increased ROE incentive. Given the emergency supply shortage in the West, it is critical to provide incentives for timely completion of transmission enhancements, including projects already underway, in order to increase supply at the earliest possible date. If a pending project fulfills the requirements listed above, and is completed by the requested deadlines, it will qualify for the incentive, which includes the 11.5% baseline cost of equity.

We find that the proposed incentive equity returns and accelerated depreciation allowances are appropriate given the critical need for power supply and infrastructure enhancements. Given the emergency nature of the power supply situation in the WSSC, a departure from our normal process for determining case-by-case return on equity allowances is warranted. A detailed, case-by-case record development process at this juncture to support a utility-specific equity allowance would delay critically needed infrastructure and is not necessary to determine a reasonable rate of return. Accordingly, we find it appropriate to use the most recently approved equity allowance for a western utility, 11.5 percent, for the uniform baseline return allowance. The Commission established the 11.5 percent through detailed analysis and this is the return level needed to attract capital under normal conditions. However, the current abnormal situation in the WSSC warrants an added incentive to make such investments more attractive than normal. Therefore, we find it appropriate to offer a sliding scale of basis point premiums to provide a clear incentive to expedite infrastructure development. The faster capacity is added, the higher the premium. Since transmission costs are a relatively small portion of delivered energy costs, the potential savings on the commodity side due to greater transmission capacity and less congestion far outweigh the cost embodied in these incentives. For example, recent commodity price differentials across California's constrained Path 15 transmission line averaged $21 per MW-hr during March 2001.[17] However, nationwide transmission costs average only $1.98 per MW-hr, or 3.1 percent of total electric costs.[18] Continuing energy commodity differentials of this magnitude clearly warrant transmission constraint reduction, which the proposed incentives would address. Finally, we note that the Commission has used rate of return incentives in the past when needed to advance the public interest.[19]

Similarly, we find that the accelerated depreciation proposal is warranted as an incentive to expedite transmission enhancements as it would provide improved cash flow and better position utilities for longer-term infrastructure investments.

3. Non-capital intensive upgrade cost recovery

The Commission proposed that, to the extent transmission owners could increase transmission capacity on constrained interfaces without capital intensive expenditures by, for example, installing new technology on existing facilities to better control voltage and power flow or by implementing new operating procedures, the Commission would allow an increased revenue requirement for their network service rates to ensure that each additional MW of capacity will generate revenues equal to the provider's current firm point-to-point rate.

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[17] See Megawatt Daily's indexes and transaction records for March 2001.

[18] This figure is derived from data reported in Energy Information Administration's Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1996; http://www.eia.doe.gov/cneaf/electricity/invest/invest.pdf.

[19] See Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 at 31,192-193 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. and Regs. ¶ 31,092 (2000) (Order No. 2000); petitions for review pending sub nom., Pub. Util. Dist. No. 1 v. FERC, 2000 U.S. App. LEXIS 26870 (D.C. Cir. Sept. 8, 2000). See also Order Setting Values for Incentive Rate of Return, Establishing Inflation Adjustment and Change in Scope Procedures, and Determining Applicable Tariff Provisions, (7 FERC ¶ 61,237 (1979)).

Comments

Commenters raise specific concerns regarding the Commission's proposed incentives for increasing capacity through non-capital intensive means. AMSC is concerned that state and federal cost allocation divisions may deter investments that aid system flow because they are categorized as "distribution" rather than "transmission" investments. AMSC requests that all upgrades that improve transmission system performance be considered transmission assets regardless of which side of the delivery point they are physically located. NRECA and APPA express concern that the Commission's proposed incentive for increasing capacity without capital intensive expenditures potentially allows gaming and would increase the transmission cost without making upgrades that broaden energy markets and benefit consumers. Stating that its retail customers pay ninety-five percent of the company's network service rates through state-regulated retail rates, PacifiCorp doubts that any significant improvement will result or that state regulatory commissions will allow the proposed cost of service treatment for these upgrades.

Commission Response

The Commission adopts the proposal to allow transmission owners that can increase transmission capacity on constrained interfaces without capital intensive expenditures to increase the revenue requirement of their network service rates to ensure that each additional MW of capacity will generate revenues equal to the provider's current firm point-to-point rate.

The Commission finds that concerns that adopting this incentive will result in gaming are unfounded. This inducement is directed to increase capacity. If no increased capacity results, the project does not qualify for the incentive and the transmission owner may not increase the revenue requirement of its network service rate.

The Commission acknowledges the distinction between distribution and transmission. These determinations will be made on a case-by-case basis.

4. Limited Section 205 Rate Filing For Upgrades

The March 14 Order proposed to allow utilities to seek the proposed incentives by way of a limited section 205 filing that would not open up existing rates to review.

Comments

Commenters express both support and opposition to limited section 205 rate filings for upgrades. Idaho Power opposes the use of wholesale adders that will not open a provider's existing rates to review, stating that this would be a new impediment in which transmission providers will absorb costs of any type of general retail rate case for each upgrade due to the impracticality of rolling in the costs. Modesto Irrigation District (Modesto) and TANC fear resulting “single issue ratemaking," and request that the Commission reject this proposal.

Some commenters also request clarification of the definition and application of the limited section 205 filings and clarification on the ratemaking and approval process for these accelerated projects. Modesto and TANC ask the Commission to clarify that these incentives would only be available for relatively small projects which will not greatly impact rates.

Commission Response

Due to the need to provide immediate relief to the West, the Commission is adopting a voluntary, abbreviated filing procedure under section 205 of the FPA for filings concerning the short-term incentives adopted by the Commission in the body of this order. Although such limited filings are not generally permitted, they are appropriate in these extraordinary circumstances surrounding the ongoing imbalances in California's electricity power supply system, as reflected by the increasing frequency of Stage 3 System Emergencies (declared when operating reserves fall below 1.5 percent) and the recent threat of rolling blackouts.[20]

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[20]The problems in California's electricity power supply system continue despite the implementation of immediate measures designed to stabilize the California markets. On December 15, 2000, the Commission eliminated the requirement that investor-owned utilities (IOUs) sell all of their resources into and buy all of their requirements from the California Power Exchange (Cal PX) and this allowed the IOUs to use their 25,000 MW of generation to serve their load without buying it at spot prices. See San Diego Gas & Electric Co., et al., 93 FERC ¶ 61,294 (2000), reh'g pending. This, in conjunction with the elimination of the Cal PX's single price auction at bids above $150, terminating the Cal PX's rate schedule entirely as of May 1, 2001 and implementing a 5% bandwidth for scheduling error in the Cal ISO's real time market was intended to provide immediate
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Such limited section 205 filings are not without precedent. Section 35.13(a)(2)(ii) of the Commission's regulations permits a utility to file a rate change under the Commission's abbreviated filing requirements if the rate change is "[f]or any service of short duration and of a type for which the need and usage cannot be reasonably forecasted (such as emergency or short term power)."[21] Unlike a general section 205 filing which opens other factors in the rate change to review, the abbreviated filing procedure limits the scope of the Commission's review in order to facilitate expeditious filing. The Commission first proposed this voluntary, expedited procedure in order to provide consumers with necessary and immediate rate relief due to tax law changes. [22]

Consistent with the rationale of Section 35.13, these abbreviated procedures are being applied here in order to encourage infrastructure development through rate incentives, and expeditious filing procedures for cost recovery. These incentives are only temporarily available since they expire after the specified construction deadlines, and are of limited applicability since they are specifically tailored to bring immediate relief to the West. Under this abbreviated procedure, the Commission will only allow filings made for the specific purpose of implementing these incentives and will only review the portion of the rate to which these incentives would apply.[23] As this abbreviated procedure will not review the costs, allocations, and rate determinants underlying the existing rates, the limited scope of the Commission's review will expedite

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[20](...continued)
help. See San Diego Gas & Electric Co., et al., 94 FERC ¶ 61,085 (2001).

[21]18 C.F.R. § 35.13(a)(2)(ii) (2000).

[22]In Order No. 475, the Commission amended the abbreviated filing requirements of Section 35.13(a)(2)(ii) to enable a public utility to voluntarily and timely file its lower rates to reflect the reduction in the Federal corporate income tax rate under the Tax Reform Act of 1986. Rate Changes Relating to Federal Corporate Income Tax Rate for Public Utilities, Order No. 475, FERC Stats. & Regs. ¶ 30,752 (1987) (citing Tax Reform Act of 1986 which reduced the Federal corporate income tax rate by twelve percentage points, effective July 1, 1987); order denying reh'g, 41 FERC ¶ 61,029 (1987).

[23]The Commission directs any other rate filing issues that are not incentives specifically adopted by the Commission in this order to be raised in a general section 205 filing.

the process, and thus facilitate the timely implementation of these incentives.

Due to the extraordinary energy situation in the West, effective upon issuance of this order, the Commission takes the unusual step of permitting public utilities who are prepared to file to implement the incentives adopted herein, to make limited 205 filings for the Commission to review. The Commission directs the applicants to clearly demonstrate how the proposals have satisfied the requirements for the incentives approved herein within the temporary timeframes outlined in this order, and to adequately explain how they increased capacity at existing constraints in the WSCC in response to the energy crisis in the West. In addition, projects currently underway must demonstrate that the construction schedule was accelerated in response to the incentive program, and the facilities were placed into service within the prescribed time frames. The Commission requires strict adherence to these filing constraints and commits to act on such filings expeditiously.

5. Roll-in of Interconnection and Upgrade Costs

The March 14 Order requested comments on whether to directly assign interconnection costs to a particular load or supply and to incrementally charge that load or supply for system upgrades, or alternatively, to roll these costs into the average system rate.[24]

Comments

Commenters who discuss the Commission's proposal to roll-in interconnection costs into the average system rate are evenly divided. Those commenters who support the rolling in of such costs condition their support on factors such as the scope and application of the proposal. PG&E supports the proposal if the activities fall within the scope of the March 14 Order, and request clarification on which types of costs will be rolled-in. Energie Azteca & Energia de Baja (InterGen) requests that the Commission clarify how rolled-in costs will apply through December 31, 2001 and recommends allowing it for necessary interconnection and transmission system upgrades identified by

[24]The Commission recognized its policy had been to allow the cost of interconnection and the cost of certain incremental system upgrades to be borne by those loads or supplies on the margin. However, the Commission noted the need for its pricing policies to minimize the cost of entry upon individual entrants due to the state of stress of the entire Western Interconnection.

studies to be completed by December 31, 2001. NRECA and APPA support the rolling in of costs if the local customers benefit from the new generation. Cogeneration Association of California (CAC) urges the Commission to roll-in costs for transmission upgrades as a permanent ratemaking principle, or alternatively, be rolled into system-wide rates for any new generator that has obtained state regulatory permits to begin construction by 2002.

Commenters who oppose rolling-in upgrade costs express concern about the impact of this incentive. Commenters allege unfair cost shifts with no reciprocal benefits, such as forced consumer subsidization of others' transmission costs. American Electric Power Company (AEP) believes rolled-in costs could encourage uneconomic siting and fears that transmission owners' recovery for transmission enhancement costs not directly assigned to generators is uncertain. SCE contends that the proposal may exacerbate the current situation, but if adopted, the cost of the upgrades should immediately be placed into a utility's rates as an adder to existing rates.

Commission Response

The emergency facing the West justifies a measure that minimizes the cost of entry for each new supply source in order to facilitate the addition of as much supply a possible and as quickly as possible. Accordingly, the Commission will roll in the costs of interconnection and system upgrades for projects that are in service by November 1, 2002.

B. Extension of Waivers for Qualifying Facilities

In the March 14 Order, we extended certain temporary waivers of operating and efficiency standards for Qualifying Facilities (QFs) that were first granted in an order issued December 8, 2000.[25] Because of the capacity shortages in California and other areas in the West, we found good cause to extend the waivers through December 31, 2001 and broaden them to apply to the entire WSCC. As with the original waivers, we required the QFs to sell additional output resulting from the waivers through negotiated bilateral agreements.

Comments

[25] San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,238 (2000).

Most commenters support extending temporary waivers of operating and efficiency standards as well as fuel use requirements. EEI contends that such waivers should apply only to those units that can address the very short-term supply shortage of California and nearby states. PG&E supports extended waivers provided that the extension does not compromise existing practices adopted by the States or host utilities, and that existing QF contract holders are held harmless from any increased cost burden. Industrial Customers of Northwest Utilities (ICNU) suggests that the Commission extend the termination date for waivers until December 31, 2003, or until such date that Commission expects significant additional generation to be available. Industrial Consumers urges the Commission to consider extending these waivers throughout the country for the pending summer peak season. Many commenters also support the Commission's decision to allow QFs to sell increased output via bilateral contracts at market-based rates.

In addition to comments on the specific waivers implemented by the March 14 Order, a number of commenters suggest that the Commission expressly permit QFs to use existing interconnection arrangements to deliver excess QF power to the grid. Some commenters ask the Commission to grant additional relief including the institution of proceedings under section 210(d) of the FPA. These commenters claim the requested relief will permit QFs to make third party sales in California which they claim will increase the supply of generation capacity in the state.

Commission Response

We reaffirm our March 14 decision to extend the QF waivers through April 30, 2002,[26] to broaden them to the WSCC, and to require that additional power made available as a result of the waivers be sold through negotiated bilateral agreements. We decline to extend these waivers to the entire U.S. at this time, but we will entertain requests for waiver on a case-by-case basis; such requests must show that serious supply/demand imbalances create circumstances that would justify a waiver under our regulations.

We clarify that the grant of these waivers does nothing to modify existing contractual obligations under PPAs, and that the extent to which a QF takes advantage of these waivers is discretionary to the QF. We decline to opine on how revenues from additional sales under these waivers may relate to payment obligations under the PPAs.

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[26] See supra note 5 and accompanying text.

With respect to the issues raised as to the rights of QFs to use existing interconnection arrangements to sell power released from or in excess of existing PPAs to third parties, and the obligations of utilities to facilitate QF sales to third parties, we will address those in a separate order issued today. [27] As to the request that the Commission institute enforcement action and reject the CPUC's revision of the avoided cost rates for sales by QFs, we will address this matter in a separate proceeding.[28] We are unable to address in this short-term order CAC's assertion that the WSCC's operating reserve requirements are inhibiting cogeneration. We would normally defer to WSCC on such matters. We would expect that the WSCC and the California ISO would attempt to minimize unnecessarily burdensome requirements that might interfere with cogeneration.

C. Additional Capacity from On-Site Generation

In the March 14 Order, the Commission adopted a streamlined regulatory procedure[29] to accommodate wholesale sales from businesses that had installed on-site generators to serve load within the WSCC. From the period beginning March 14, 2001 through December 31, 2001, owners of generating facilities located at business locations in the WSCC and used primarily for back-up or self-generation, who would become subject to the Federal Power Act by virtue of sales of power from such facilities, will be permitted to sell power at wholesale from such facilities to non-affiliated entities within the WSCC without prior notice under Section 205 of the FPA. Pursuant to Section

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[27] See Order Granting Motions for Emergency Relief and Proposed Order Directing Interconnections Under Section 210(d) and Establishing Further Procedures (Docket No. EL01-47-002).

[28] California Cogeneration Council, et al., Petition for Enforcement Action Pursuant to Section 210(h)(2)(B) of PURPA (Docket No. EL01-64-000) (filed April 5, 2001).

[29] The Commission narrowly defined the measure as only streamlining Commission filing requirements for certain actions that are otherwise agreed to among the relevant parties. The measure did not abrogate or supersede any existing contracts or obligations, exempt any person from existing environmental, safety, or reliability requirements, authorize the feeding of power into the grid where not otherwise authorized, authorize a retail customer to violate any rules or retail tariff provisions that have been properly imposed on the retail sales made to those customers, or impose new substantive obligations on any person.

205(d), the Commission found good cause to waive the 60-day prior notice requirement for such sales.[30] The Commission further granted waiver of its regulations consistent with its orders on market-based rates and authorized market-based rates during the identified time period.[31]

The Commission also stated that to the extent mutually-agreed upon interconnection agreements become jurisdictional through the use of the interconnection for a jurisdictional sale during the specified period, the Commission waived the prior notice requirement for the duration of the interim period. The Commission allowed the filing of such jurisdictional interconnection agreements to be postponed and made along with the reports of sales pursuant to the procedures discussed above.

Comments

A number of commenters support waivers associated with the sale of on-site and self-generation from businesses not primarily engaged in the sale of electricity at wholesale. EEI notes that safety and reliability must be preserved. NRECA and APPA request the expansion of the waivers for on-site generation to the rest of the country, and SCE suggests an extended termination date for waivers. PacifiCorp requests that the Commission clarify whether the March 14 Order precludes self generators from imposing increased costs on public utilities, and requests market-based rates for self generation sales only for that portion above historic levels.

NRECA and APPA suggest that the Commission waive jurisdiction to the extent possible under the FPA over consumers with on-site generation used primarily for on-site load, and who are not substantial participants in wholesale markets. CPUC states

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[30]16 U.S.C. § 824d (1994).

[31]The Commission required that wholesale purchasers of power from such facilities to report to the Commission the names of each such seller from whom power was purchased, the aggregate amount of capacity and/or energy purchased from each seller, and the aggregate compensation paid to each seller. The Commission allowed the purchaser to make one report for all purchases pursuant to this paragraph, and, if it otherwise files quarterly transactions summaries with the Commission, may include this report as a separate section of its transaction summary for the first calendar quarter of 2002. The Commission directed the purchaser to file this report with the Commission by April 30, 2002 if the purchaser does not otherwise file quarterly transactions summaries. See March 14 Order at n. 18, 19.

that there is an unresolved legal question of whether and to what extent distributed generation is subject to the Commission's jurisdiction.

Commission Response

We reaffirm this measure as adopted in the March 14 Order and extend the measure until April 30, 2002. With regard to the request that we waive jurisdiction entirely over such entities, we note that section 201(e) of the FPA defines a "public utility" as "any person who owns or operates facilities subject to the jurisdiction of the Commission..."[32] Section 201(b) of the FPA states that the Commission shall have jurisdiction over all facilities for the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce.[33] Thus, by virtue of sales of power at wholesale from generating facilities located at business locations in the WSCC and used primarily for back-up or self-generation, these businesses become public utilities subject to the Commission's jurisdiction under the FPA.[34] Section 205 of the FPA further requires public utilities to file with the Commission rate schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission.[35] It is not within the Commission's authority to waive the statutory requirement that public utilities file rate schedules under section 205, but the Commission may prescribe the time and form of such filings, find good cause to waive the 60-day prior notice requirements for these sales and, waive certain parts of its regulations concerning such filings.[36]

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[32]16 U.S.C. § 824 (1994).

[33]Id; Contrary to NRECA and APPA's assertion, the Commission's jurisdiction under the FPA is not waivable.

[34]Sales for resale of distributed generation would also fall under the Commission's jurisdiction.

[35]16 U.S.C. § 824d (1994).

[36]Id; The Commission has generally waived the following portions of its procedural regulations: most of Subparts B and C of Part 35 (documentation), Part 41 (accounting verification), Part 101 (prescribed Uniform System of Accounts), and Part 141 (annual reports). In addition, where requirements are statutory, the Commission has
(continued...)

We will not expand the scope of this measure beyond the Western Interconnection or extend it beyond April 30, 2002. This blanket measure is aimed at an emergency situation in the West. We will consider similar individual proposals by entities located in other regions.

D. Purchases of Demand Reduction

Effective on the date of the March 14 Order, the Commission allowed retail customers, as permitted by state laws and regulations, and wholesale customers to reduce consumption for the purpose of reselling their load reduction at wholesale. The Commission noted that the sale of these "negawatts" would help maintain the reliability of the grid by providing additional load resources when generating resources are scarce. Consistent with its discussion regarding sales from generating facilities located at business locations and used primarily for back-up or self-generation, the Commission granted a blanket authorization to allow these sales at market-based rates, subject to the requirement that similar information on these transactions be reported on a quarterly basis.[37]

The Commission stated its intention to promote complementary wholesale programs that did not undermine existing state demand-side management (DSM) programs or other state rules governing retail sales. The Commission requested comments on how helpful this action is and how well it can be accomplished consistent with state jurisdiction over retail sales. The Commission also requested comments on the desirability of accelerating action on the December 15 Order which directed that the

[36](...continued)
allowed such sellers to make shortened filings to satisfy Part 33 (disposition of facilities) and Part 45 (interlocking positions), and has granted blanket authorizations for issuances of securities (Part 34); See, e.g., FirstEnergy Generation Corp., 94 FERC ¶ 61,177 (2001); FirstEnergy Services, Inc., 94 FERC ¶ 61,052 (2001).

[37]The Commission noted that the ISO instituted a market-based wholesale demand responsiveness program on a four-month trial basis during the summer of 2000. Under this program, the ISO paid participants a monthly "capacity" payment in exchange for the ISO's ability to curtail these loads. Initial participation in the ISO's trial program reached 180 MW.

California ISO establish an integrated day-ahead market in which all demand and supply bids are addressed in one venue.[38]

Comments

Most demand reduction comments refer to the establishment of an active market for load reduction or demand. For instance, DWR recommends removing rigid market rules designed for merchant generation that impeded load participation.

Some commenters emphasize the difficulty of implementing such a program. While Xcel agrees with the Commission's treatment of DSM, it points out the difficulty of determining how to measure and settle the reductions if certain demand reductions will be determining the market-clearing price. SRP states that its retail tariffs as well as those of most other distribution utilities prohibit retail customers from selling into the wholesale market. ACC asserts that other economic factors such as local impacts must be considered. SCE doubts the proposal will provide any relief from power shortages as it is unaware of any market in California that sells "negawatts." Reliant Energy Power Generation, Inc. (Reliant) proposes a WSCC-wide program to provide load relief from interruptible load customers across the entire WSCC region to any deficit WSCC control area.

PG&E perceives no impediment to the Commission's action if it does not conflict or duplicate a state-imposed load management program, while Washington Utilities and Transportation Board (WUTC) emphasizes its exclusive jurisdiction over retail service and suggests that this proposal extends the Commission's reach. Commenters acknowledge ongoing state efforts to reduce consumption such as the sale of demand which is already in place under the California ISO's 2001 Demand Relief Program. PacifiCorp points out that it is actively seeking demand reduction on its system. CPUC notes ongoing efforts at the state level for waivers of prior notice for rate schedule amendments and treatment.

Some commenters, such as WUTC, emphasize the states' exclusive jurisdiction over retail customers or point out a need to coordinate with state DSM programs.

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[38] See December 15 Order, 92 FERC at 62,016-17.

WUTC expresses concern that the Commission's proposal may undermine the demand reduction tools it has in place. NRECA and APPA claim that the Commission will overreach its jurisdiction if it describes pure load reduction agreements as sales of energy at wholesale. EEI encourages the Commission's efforts, but notes that many DSM matters are under state jurisdiction.

A few commenters address whether the Commission should accelerate the California ISO's integration of demand-reduction bidding. SDG&E and SCG support accelerating action on establishing an integrated supply/demand day-ahead market at the California ISO. Among their specific recommendations, SDG&E and SCG supported a "short forward" market similar to those managed by the PJM and New York ISOs. DWR states that to the extent that the Commission accelerates development of integrated ISO dispatch of load, power and payment mechanisms that occur in the day ahead time period in addition to the real-time, the Commission should ensure that such payments are not structured or priced to thwart the objectives of forward contracting.

Commission Response

We reaffirm the March 14 Order's action concerning purchases of demand reduction. We recognize that such a program may be more efficient if there were an organized market for "negawatts" established. Although we will be receptive to proposals brought to us to establish such a market, we believe benefits can be obtained through negotiated arrangements in the absence of an organized market. We reiterate what we stated in the March 14 Order with respect to our recognition of the important role states play in the regulation of retail service. Nothing herein authorizes a retail customer to violate existing state laws or regulations, or contract rights.

As noted earlier, the Commission has jurisdiction over public utility sales of electric energy for resale in interstate commerce, and we do not believe we overreach our jurisdiction by asserting it here.[39] To the extent the load reductions will be sold at wholesale, they fall under the Commission's jurisdiction. However, the Commission is not attempting to supersede state authority over retail customers. As it stated in the March 14 Order, the Commission is promoting wholesale programs that complement existing state DSM programs or other state rules governing retail sales. Our goal is not to assert new jurisdiction but to work cooperatively with the states to achieve a common good.

[39] 16 U.S.C. § 824 (1994).

With respect to the issue of the California ISO establishing an integrated day-ahead market in which all demand and supply bids are addressed in one venue, the few commenters who responded favored accelerating this proposal so long as forward contracting objectives were not hindered. The Commission will consider these comments as it moves towards the goal of accelerating the California ISO's integration of demand-reduction bidding.

E. Contract Modifications to Promote DSM

In the March 14 Order, the Commission noted the potential opportunities for public utilities to make alternative demand-side arrangements with their wholesale customers. The Commission found good cause to grant waiver of the FPA's prior notice requirements for any rate schedule amendments that may be required to effectuate mutually agreed upon DSM alternatives that change contractual terms and conditions within the Commission's jurisdiction. This measure became effective upon the issuance of the March 14 Order. The Commission set December 31, 2001 as the deadline for amending the filed rate schedule which was required to consist of the FERC rate schedule numbers, the load reduction negotiated under the DSM arrangement (MW/MWh), total compensation, and the name of each affected wholesale customer.[40]

There were no substantive comments addressing this proposal. The Commission reaffirms its adoption of this measure as outlined in the March 14 Order.

F. DSM in Cost-Based Rates

The Commission also acknowledged that utilities sometimes continue to operate under cost-based rates which often incorporate formulas that are intended to track the actual out-of-pocket (i.e., incremental) cost that was incurred to generate or purchase the energy. However, most rate schedules did not recognize that DSM costs are a form of out-of-pocket or incremental cost which discouraged utilities from engaging in DSM during generation shortages. In order to eliminate the disincentive to rely upon DSM during these times, the Commission clarified that, effective upon issuance of the March

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[40]The Commission noted that this paragraph applied to revisions to contracts to permit a wholesale customer's participation in any utility DSM programs, including those of an ISO or power exchange.

14 Order, DSM costs should be treated consistently with all other types of incremental and out-of-pocket costs.

There were no substantive comments addressing this proposal. The Commission reaffirms its adoption of this measure as outlined in the March 14 Order.

G. Use of Section 210(d) Interconnection Authority

In the March 14 Order, the Commission cited Section 210(d) of the FPA as authorizing the Commission, on its own motion and after following certain procedures, to issue an order requiring the same actions an applicant may request with respect to interconnections.[41] The Commission sought comments on whether the exercise of its authority under this section could help alleviate any existing impediments that may be preventing generating resources from reaching load. If the exercise of this authority could be warranted, the Commission sought comments on whether the Commission could make some of the required findings generically for the WSCC region in order for the Commission to respond quickly if appropriate circumstances arose.

Comments

Cogenerators are generally supportive of the Commission's efforts to encourage the interconnection of new generation. Calpine, Industrial Consumers and TransAlta specifically support the Commission's exercise of its authority under section 210(d) of the FPA, with Calpine requesting assurance that California's utilities will not impede the sale of QF generation to third parties by arbitrary interconnection requirements.[42] CCC, in its motion for emergency relief, specifically requests that the Commission exercise section 210(d) authority to facilitate sales by QFs to third parties.

[41]The Commission highlighted Section 210(d)(3)(A), (B), (C) and (D). 16 U.S.C. § 824a-3.

[42]Calpine states that the CPUC's order directing utilities to pay QFs for future deliveries does not maximize California QF generation. See Mimeo at 6 (citing Order Instituting Rulemaking into Implementation of Pub. Util. Code § 390 , D.01-03-067 (2001)). CCC's Petition for an Enforcement Action alleging that CPUC's decision violates PURPA is currently pending in Docket No. EL01-64. In addition, the issue of California utilities impeding the sale of QF generation to third parties is now pending in Docket No. EL00-95.

While not specifically citing to Section 210(d) of the FPA, a majority of commenters who discuss interconnection policy support establishing uniform interconnection standards. A number of commenters assert that entry costs for new electricity supply would be reduced by eliminating discriminatory or economically disadvantageous procedures related to interconnection. The SRP opposes FERC-directed interconnections, preferring greater flexibility for transmission owners to negotiate the terms of service with generators.

Several commenters recommend specific reforms of the interconnection process. For instance the California ISO requests Commission approval of its recently filed "New Facility Interconnection Policy" (NFIP), which is intended to establish one policy applicable to all interconnections on the California ISO grid.

Commission Response

In response to the commenters' recommendations regarding the uniformity of interconnection standards and other concerns, we note that the Commission has responded to similar requests in other proceedings and has so far found it unnecessary to adopt uniform interconnection standards. [43] We will not further address this request in this limited order for expeditious actions to aid the West. We also note that the issue of interconnection policies for California utilities are the subject of other pending proceedings.[44]

With respect to the use of FPA section 210(d), as noted in section B supra, the Commission is today instituting section 210(d) proceedings and requiring California

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[43]See, e.g., Entergy Services Inc., 91 FERC ¶ 61,149 (2000), clarified and order on reh'g, 94 FERC ¶ 61,257 at 61, 905 (2001); Virginia Electric and Power Co., 93 FERC ¶ 61,307 (2000), reh'g denied, 94 FERC ¶ 61,164 at 61,589 (2001); American Electric Power Service Corp., 91 FERC ¶ 61,308 at 62,053 (2000), clarified and reh'g denied, 94 FERC ¶ 61,166 (2001).

[44]The Commission is currently reviewing the California ISO's NFIP in Docket Nos. EL00-95-023 and EL00-98-022, and related filings by SDG&E (Docket Nos.EL00-95-022; EL00-98-021), PG&E (Docket Nos. EL00-95-024, EL00-98-023) and Southern California Edison Co.(Docket Nos. EL00-95-025 and EL00-98-024).

utilities and the California ISO to provide interconnection and related services to enable QFs to make third party sales in certain circumstances.[45]

H. Longer-Term Regional Solutions

The March 14 Order focused primarily on short-term regulatory actions that it could take to improve energy supply conditions in the West. However, the Commission recognized that a regional perspective should guide its decisions regarding investment in new electric and gas infrastructure. The Commission acknowledged that any long-term solution to address and prevent the recurrence of the current crisis must be developed on a west-wide basis, with appropriate input from all of the affected states. Stating that problems of inadequate generation supply and poor demand responsiveness are exacerbated by localized electric transmission and gas pipeline capacity bottlenecks, and the fragmentation of Western market rules, the Commission advocated a west-wide RTO or a seamless integration of Western RTOs for designing and implementing a long-term regional solution. The Commission reaffirmed its commitment to the policy course set forth in Order No. 2000 and noted its continued cooperation with transmission owners, market participants and affected state utility commissions to encourage the further development of RTOs.

Comments

Many commenters agreed with the need for long-term solutions for the Western electricity crisis that include the implementation of an integrated western transmission system administered by one or more regional transmission organizations (RTO), regional interconnections, and incentives for investing in infrastructure.

A few commenters discuss the "phantom congestion" issue, which they describe arises when the California ISO reserves transmission capacity for existing transmission contracts (Existing Contracts), the unused portion of which is not released to the market for use by market participants.[46] While acknowledging that the issue is currently being

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[45]See Order Granting Motions for Emergency Relief and Instituting Section 210(d) Proceeding (Docket Nos. EL00-95-020, EL00-98-019, EL01-47-002, EL01-72-000).

[46]See Comments by MSCG. In addition, California ISO's comments state that Existing Contracts often contain scheduling timelines that differ from the ISO's Day-
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addressed in settlement negotiations,[47] Morgan Stanley Capital Group (MSCG) proposes to make available conservatively estimated amount of unused existing contract transmission to market participants unless it is explicitly reserved by Existing Contract customers in the day-ahead market.

Commission Response

The Commission shares the commenters' support for long-term regional solutions and backs ongoing efforts to ensure sufficient electricity transmission capacity for the est.[48] While the Commission is focusing on short-term, immediate relief to the West in this order, the Commission remains committed to the policies set forth in Order No. 2000 and is committed to an integrated Western transmission system administered by one or more RTOs.[49]

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[46](...continued)
Ahead and Hour-Ahead scheduling timelines, in which transmission capacity is reserved, but often not used by existing rights-holders. California ISO further explains that it can use in real time any transmission capacity that has not been scheduled by existing rights-holders in the Hour-Ahead scheduling process, but the reserved and unused transmission capacity is unavailable to market participants in the ISO transmission markets (i.e., the Day-Ahead and Hour-Ahead scheduling processes).

[47]See Docket No. ER00-2019 (settlement negotiations regarding Amendment 27's proposed new methodology for recovering, through a Transmission Access Charge, the embedded cost of transmission facilities comprising the California ISO-controlled grid)

[48]The Commission supports the recent Electricity Transmission Roundtable hosted by the Western Governors' Association to identify decision-making bottlenecks related to planning, financing, siting and permitting that inhibit investments in needed transmission capacity. See Press Release, Western Governors' Association, Governors Recommend Actions to Remove Electricity Transmission Bottlenecks, Expand Capacity (May 9, 2001), available at http://www.westgov.org/wga/press/energy_transmission.htm.

[49]See Order, Granting with Modification, RTO West Petition for Declaratory Order and Granting TransConnect Petition for Declaratory Order 95 FERC ¶ 61,114 (2001) (Order provides preliminary guidance with respect to governance, scope and configuration, and liability of RTO West, and addresses TransConnect's October 16

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The Commission recognizes that "phantom congestion" is a market inefficiency that must be addressed and rectified either through the settlement negotiations regarding the ISO's transmission Access Charge, or in a separate proceeding.[50] While the phantom congestion issue is currently being addressed in overall settlement negotiations under Docket No. ER00-2019, the Commission will address phantom congestion in a separate proceeding in the event the negotiations do not resolve this issue.

II. Natural Gas Pipeline Capacity

In order to provide regulatory incentives to build new natural gas infrastructure in the WSCC to support increased electric generation, the March 14 order solicited comments of interested persons on how it might exercise its authority over new pipeline construction to assist the present situation. In particular, the Commission requested comments on the following proposals:

1) waiving the blanket certificate regulations to increase the dollar limitations for facilities under automatic authorization to $10 million and for prior notice authorizations to $30 million;

2) offering blanket certificates for construction or acquisition and operation of portable compressor stations to enhance pipeline capacity to California; and

3) offering rate incentives to expedite construction of projects that will make additional capacity available this summer on constrained pipeline systems.

The March 14 order noted that the Commission's current policy of allowing rolled in rates for facilities built under the current blanket authorization of $20.6 million or less would continue to apply. However, we requested comments on whether blanket authorizations exceeding $20.6 million should also be rolled in.

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[49](...continued)
filing regarding the proposed governance structure, proposal to file rates unilaterally and its proposed transmission planning and expansion function.) The Commission directed Desert STAR to file its RTO proposal by May 31, 2001, and conditioned the market mitigation and monitoring remedies adopted in its April 26 Order on the California utilities and California ISO filing their RTO proposal by June 1, 2001.

[50]See California Independent System Operator Corp., 91 FERC ¶ 61,205 at 61,727 (2000).

The Commission also expressed concern that its actions to expedite new capacity for gas to serve California and the West may only be effective to the extent there is available local distribution capacity to deliver gas downstream of the interstate pipeline. However, the Commission noted, the availability of take-away capacity is within the states' control rather than the Commission's. Therefore, the Commission requested pipelines to coordinate their efforts with local distribution companies, public utilities, and state officials to ensure that their will be sufficient local take-away capacity to accommodate any additional interstate pipeline capacity.

General Comments

In addition to comments on the specific proposals described above, parties also commented on the need for the Commission to coordinate with state and federal agencies to streamline and expedite the process for increasing pipeline capacity. NGSA suggests that if such coordination does not work, the Commission should use its authority under Section 17 of the Natural Gas Act to convene joint boards or hearings with affected state agencies to facilitate needed pipeline system enhancements to serve the West. Forest Service recommends the Commission include federal land management agencies when meeting with state regulators since such agencies may have jurisdiction over the siting of natural gas and electrical generation and transmission facilities on federal lands. Forest Service also recommends that all natural gas or electricity providers who intend to upgrade notify all affected land management agencies as far in advance as possible so that federal land management agencies can align limited resources for processing and approving such applications.

NGSA, InterGen, Questar, Kinder Morgan and Williams comment regarding staffing issues. These comments include supporting existing Commission staff organization, adding Commission staff to deal with western projects, assisting other federal and state agencies to identify critical staffing needs, and creating a special "compression-only" staff in the Office of Energy Projects to address the relevant issues in a more timely fashion.

The parties commenting on the local take-away capacity issues generally concur with the Commission's collaborative approach to ensure that downstream take-away capacity reasonably matches upstream capacity. IEP maintains that California must make a simultaneous effort to encourage take-away capacity. El Paso is concerned that expansions to California may not be matched by expansions within California. Enron emphasizes the need to coordinate upstream and downstream capacity expansion because the current imbalance, more delivery capacity to California than take-away capacity, will likely grow.

Williams agrees with the Commission that the cooperation of local distribution entities, public utilities, and state officials will be needed to insure sufficient local take-away capacity and seeks the Commission's support in dealings with these entities. Kern River maintains the Commission should condition approval of expansions on the existence of sufficient take-away capacity expressing the concern that the integrity of existing firm service should not be compromised by the rush to build interstate pipeline capacity to California.

Commission Response

Our coordination with other agencies in processing pipeline certificate applications is evolving into the more streamlined approach advocated by commenters. We are continuing to work with other agencies to enhance and accelerate the certification process. The Commission has consistently shown its ability and commitment to expedite pipeline proposals in response to critical needs, and we will continue to process all applications as expeditiously as possible. With respect to our authority to convene formal joint boards to facilitate pipeline enhancements, we do not believe it is necessary to do so at this time. Regarding staffing concerns, the March 14 order explained that our staff is properly allocated to expedite the processing of gas infrastructure projects. We see no need to realign our staff as suggested by commenters; further realignment at this stage of the energy emergency could be counterproductive.

Several commenters agree with the March 14 order's assertion that pipelines must coordinate their efforts with downstream entities in order to make sufficient takeaway capacity available. Kern River suggests that the Commission should condition expansions upon the existence of sufficient takeaway capacity. However, there is no mandate for the Commission to require a downstream non-jurisdictional entity to match the planned upstream capacity. We are pleased to note that the CPUC has started proceedings addressing takeaway capacity issues. The Commission is also convening a technical conference on May 24, 2001 on take away capacity and its relationship to interstate pipeline capacity and intrastate pipeline capacity.[51]

A. Raising the Cost Limitations for Part 157 Blanket Certificates

[51] Notice of the conference was issued under Docket No. PL01-4-000.

Section 157.208 of the Commission's regulations limits the cost for projects qualifying for automatic authorization to $7.4 million and for projects qualifying for prior notice authorization to $20.6 million. In the March 14 order, the Commission requested comments on whether it should waive the blanket certificate regulations to increase the dollar limitations under automatic authorization to $10 million and under prior notice authorizations to $30 million for those projects that would serve California and the West. If so, the Commission asked whether the current policy of allowing rolled in rates for facilities built under the blanket authorization should apply to facilities constructed at costs between $20.6 million and $30 million.

Comments

Pinnacle, Duke, EEI, El Paso, EPSA, LPPC, NWIGU support raising the dollar limitations on blanket authorizations under section 157.208 of the Commission's regulations. NGSA thinks the proposal is a reasonable one that would encourage interstate pipeline infrastructure improvements in California and the West. Other commenters support the change but propose higher limits. Questar believes the increases suggested by the Commission are not high enough to facilitate much additional construction in the near term. PG&E supports increasing the limits to $15 million for automatic authorizations and $45 million for prior notice authorizations, while EEI thinks the limits should be $20 million and $60 million, respectively. Williams would raise the limit for prior notice authorizations to $40 million to permit more projects to qualify. WPSC urges that, if the Commission adopts a new limit, it do so only until the end of 2002 to allow for further review.

Contending that it will allow ever-larger pipeline projects to go forward without meaningful Commission review, APGA opposes raising the dollar limitations for blanket certificate authorizations.

El Paso, Kinder Morgan, and PG&E support a presumption of rolled-in rate treatment for blanket certificate authorizations that exceed $20.6 million. NGSA supports the presumption but only up to the $30 million limit suggested by the Commission. NGSA also states that the Commission should re-affirm its current policy that any preliminary endorsement of rolled in rates in a certificate proceeding can be challenged by any party in the subsequent rate case where the pipeline seeks to implement roll-in.[52] NWIGU comments that facilities approved under prior notice authorizations that cost more than $20.6 million should meet a system-benefit analysis for rolled in rate treatment to apply.

Commission Response

After consideration of the comments, we believe it is in the public interest to waive our regulations, on a temporary basis, to raise blanket certificate limits to $10 million for automatic authorizations and to $30 million for prior notice authorizations for all pipelines that deliver gas in the WSCC. We believe that these amounts are sufficient to allow pipelines to quickly add capacity while effectively limiting the size of the projects. This temporary waiver applies only to those projects that will be built and placed in service by April 30, 2002. A pipeline intending to construct facilities under our prior notice regulations at a cost between $20.6 million and $30 million should note the temporary waiver in its prior notice application.

To further expedite prior notice projects, we will also consider requests to shorten the 45 day protest period that would otherwise be required under section 157.205(d). We will respond to such requests in the notice of the application issued by the Secretary of the Commission.

We have determined that the expanded blanket authority should be available to all pipelines that deliver gas in the WSCC. While the initial impetus for providing the regulatory means to quickly add pipeline capacity was the problems in California, we believe it is prudent to permit these pipelines that deliver gas in the WSCC to quickly add capacity where necessary to preclude insufficient pipeline capacity exacerbating the current energy problems.

Under our Certificate Policy Statement, pipelines can roll-in costs incurred in constructing facilities pursuant to our Part 157, Subpart F regulations.[53] We will allow pipelines to roll-in the cost of facilities that are built, and placed in service by April 30, 2002, under the expanded authorizations as we do for any automatic or prior notice authorization. We believe this will encourage pipelines to construct needed facilities and

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[52] Citing Equitrans, L.P. et al, 91 FERC ¶ 61,041 at 61,151, reh'g denied, 92 FERC ¶ 61,010 (2000).

[53] See Certification of New Natural Gas Pipeline Facilities, Statement of Policy, 88 FERC ¶ 61,227 at 61,754 (1999).

thus accomplish our goal of increasing pipeline capacity to address the current crisis in California and the West, and to prevent serious capacity shortages elsewhere in the country.

We note that section 157.208(b) of our regulations prohibits pipelines from segmenting projects to meet the automatic or prior notice cost limitations. Nothing we are contemplating in this order negates that prohibition.

B. Eligible Facilities in Automatic and Prior Notice Blanket Certificates

In the March 14 order, the Commission stated that it was seeking proposals for expediting the approval of pipeline infrastructure needed to serve California and the West, particularly during the upcoming spring and summer. The Commission noted that planned pipeline maintenance, and the resulting reductions in transmission capacity, usually occur during the spring and summer when power requirements are at their highest in California and the West. Therefore, the Commission sought comments on a proposal to offer blanket certificates for construction or acquisition and operation of portable compressor stations that could be used quickly to avoid reduction in the amount of pipeline capacity to California this summer. The Commission also stated that it would be receptive to other proposals that achieve these goals.

Comments

Commenters, including CPUC and ACC, generally support the Commission's initiatives to increase natural gas pipeline capacity. Others express reservations. APGA cautions the Commission to consider the long-term wisdom of authorizing pipeline construction that has as its sole purpose increasing the growing reliance of the electric power industry on natural gas. NGSA and Kern River state no expansion should impede the firm rights of existing customers.

Parties commenting on expanding blanket authorizations to allow for portable compression generally support it. Noting the multi-state nature of gas delivery requirements, ACC, Pinnacle, ConEd, EEI, El Paso, LPPC, NGSA, O&R, PG&E, Questar, and Xcel support expanded blanket authorization not just in California but anywhere in the West. SRP is concerned that, due to existing constraints in Arizona, the proposal could potentially result in blackouts in the Phoenix area if portable compressors are used to enhance pipeline capacity only to California. Duke and Kinder Morgan submit that the Commission should allow participation nationwide to allow construction of facilities to aid in eliminating shortages or bottleneck situations in other regions.

Williams contends that to support maximum flexibility, blanket certificate authority should allow the installation of portable compressors not only at existing compressor station sites but also at new sites to maximize opportunities for new throughput. Williams also urges the Commission to work with the Environmental Protection Agency to facilitate and streamline the permit process for portable compressors since it believes the air quality permit process will be a bottleneck in the permitting process.

Some commenters propose that the Commission further expand the definition of facilities eligible for automatic or prior notice blanket certificate authorization under section 157.202(b)(ii). For example, El Paso supports permitting mainline expansions to be eligible for blanket certificates, Kinder Morgan proposes to allow looping of mainlines and nonportable mainline compression to qualify, and EEI believes there should be no restriction on the types of facilities that can be built under blanket authorization.

Commission Response

After consideration of the comments, we believe it would be in the public interest to temporarily waive our regulations to expand the definition of eligible facilities under section 157.202 of our regulations for those pipelines that deliver gas in the WSCC. This is a reasonable near-term solution that can quickly enhance the pipeline infrastructure in the Western United States. Specifically, we will temporarily waive sections 157.202(b)(2)(ii)(A), (B), (C), and (F) of our regulations to include as an eligible facility a main line, an extension of a mainline, a facility, including compression and looping, that alters the capacity of a main line, and temporary compression that raises the capacity of a mainline. The cost limit waivers can apply to newly eligible facilities. This temporary waiver is in effect through April 30, 2002.

We emphasize that projects under the expanded blanket authority will remain subject to our existing environmental regulations and compliance provisions.

To determine whether these expanded blanket authorizations have been successful in encouraging pipeline expansion to alleviate the present crisis, we will require pipelines that are granted waivers to our Part 157 regulations to file a report by

June 1, 2002 describing any projects undertaken pursuant to the expanded blanket authorizations including projects that expanded mainline capacity and those that exceeded the permanent dollar limits.

C. Rate Incentives to Expedite Construction

The Commission requested comments on offering rate incentives to expedite construction of projects that will make additional capacity available this summer on constrained pipeline systems that deliver gas in the WSCC.

Comments

Some commenters oppose the use of rate incentives for several reasons. APGA states there is no discussion about what the incentives would be or why they are needed. Coral Energy states rate incentives are not needed and pipelines Kern River, El Paso, and Transwestern have already submitted applications for capacity expansion under current rules and rates. Kern River also claims such incentives are not needed and there is no evidence that existing rate design policies are not working. NGSA points out that because market forces are working to bring needed capacity on, rate incentives for additional capacity are not necessary to resolve the western energy problems. Moreover, NGSA observes that offering special incentives to relieve constraints may inadvertently send a signal that the Commission is willing to provide similar rate premiums in response to future capacity constraints and encourage delays in expansions if there is an expectation that regulatory return premiums will be provided when constraints develop.

El Paso believes that rate incentives are unlikely to impact capacity for this summer and recommends that the Commission expedite action on pending projects. Conversely, Pinnacle supports rate incentives on constrained pipelines available by this summer. InterGen advocates rolled-in treatment for incremental pipeline facilities to be constructed and encourages incentive rates of return and accelerated depreciation rates to stimulate construction.

Kinder Morgan supports additional rate incentives by increasing rate flexibility. For small projects, Kinder Morgan states a pipeline should be able to charge either its pre-existing rate or add an incremental rate as a surcharge for shippers on particular projects. The pipeline would file a tariff sheet with the proposed rate treatment before the service begins and the rate treatment would be reviewed in the pipeline's next rate proceeding.

PG&E supports the grant of reasonable rate-related incentives, provided that rates remain just and reasonable. Appropriate rate incentives could include presumptive rolled-in treatment for emergency related construction under blanket certificates. PG&E proposes extending such treatment beyond December 31, 2001, to include construction activities to provide extra capacity through the 2001/2002 winter period. Finally, PG&E recommends the Commission consider returning to a policy of allowing roll-in of project costs where there are system benefits and the impact will not be significant.

Williams submits that offering rate incentives to expedite construction of projects in time for the summer is appropriate because accelerated projects have higher inherent risks of scheduling and permitting delays, cost overruns, and the regulatory approvals required by multiple agencies. Questar supports rolled-in rate treatment. SRP supports rate incentives. Xcel supports the use of rate incentives but recommends establishing a sunset date for waivers.

Commission Response

No party has proposed rate incentives that would make additional capacity available this summer. Indeed, many commenters have stated that incentives are not needed or that incentives would not have an impact upon capacity for this summer. Some commenters who support rate incentives offered no tangible proposals. We cannot evaluate such support without content. Other commenters ask for rate incentives that either are already at their disposal (e.g., higher rates of return and accelerated depreciation rates may be proposed for incremental rates) or are being approved herein (i.e., allowing the roll-in of project costs up to the temporary blanket certificate limit of $30 million).

Kinder Morgan's request for rate flexibility as a rate incentive may not guarantee that a rate for a project is in the public convenience and necessity as required in section 7 certificate cases. That is, a pipeline, under Kinder Morgan's proposal, may opt to charge an existing rate that does not recover the costs of a project, resulting in the subsidization of a project by the existing customers. This runs afoul of our Certificate Policy not only by shifting costs to existing customers, but also by not sending the proper price signals to the market. If we were to approve rate incentives for natural gas projects, those incentives should not negatively affect existing customers. Since Kinder Morgan's proposal for rate flexibility has the potential to negatively impact existing customers, we will not adopt it.

PG&E asks that the Commission return to its previous pricing policy that would allow project costs to be rolled-in when the rate impact will not be "significant." We view this recommendation a step backwards. As stated above, we want the proper price signals to be sent to the market, and the subsidization inherent in the previous pricing policy masked those signals. Thus, we will not reverse our current certificate pricing policy.

We believe, based on the filed comments, that the demand in the Western U.S. market is an adequate rate incentive for the short term. In addition, there are other rate incentives, albeit more of a long-term nature, in existence and at the disposal of the pipelines that deliver gas in the WSCC. Pipelines have the right to propose market-based or negotiated rates subject to the framework outlined in our January 31, 1996 statement of policy.[54] This policy statement also revisited and revised our earlier policy to permit incentive rates which offer pipelines the possibility to earn higher returns.[55] In addition, a pipeline is free to design incremental rates for projects which may propose rates of return and depreciation rates than differ from those used on a system wide basis.[56]

Further, as detailed above, we are allowing pipelines that deliver gas in the WSCC to roll in the costs of those blanket certificate activities that exceed $20.6 million, up to the temporary blanket certificate limit of $30 million until April 30, 2002. We believe that this, coupled with the demand for energy, will serve as an adequate incentive to construct new pipeline capacity this summer.

III. Hydroelectric Power

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[54] See, Statement of Policy and Request for Comments, 74 FERC ¶ 61,076 (1996) (Docket Nos. RM95-6-000 and RM96-7-000).

[55] See, Policy Statement on Incentive Regulation, 61 FERC ¶ 61,168 (1992).

[56] See, e.g., Algonquin Gas Transmission Company, 71 FERC ¶ 61,069 (1995), Algonquin Gas Transmission Company, 83 FERC ¶ 61,200 (1998). In these orders, we approved incremental rates for service on new laterals where the depreciation rate matched the life of the shipper's contract as opposed to using the system wide depreciation rate. See also, Granite State Gas Transmission, Inc. 83 FERC ¶ 61,194 (1998). In this order, the Commission approved a rate of return for an LNG plant without reference to the company's overall existing rate of return.

In the March 14 Order, the Commission noted that any action taken to enhance the generation from the 326 projects that it regulates in the WSCC, consistent with protecting critical environmental resources, can improve the energy picture for the Western states. The Commission's review of hydrologic conditions indicated that they are not conducive to maximizing hydropower generation during the summer of 2001. The Commission stated that modification of operational constraints on licensed projects[57] could increase generation from existing hydroelectric facilities, provide additional power during peak-load periods, and increase the ability of projects to provide ancillary services to the power system. The Commission conditioned its approval of any such proposed license modifications on consultation with federal and state resource agencies and environmental review of the proposal.

In addition, the Commission stated that many hydropower projects are potentially capable of more fully using the available water resources to contribute to the electric capacity and energy needs. The Commission identified principal areas in which improvements could be made: (1) addition of new capacity units; (2) generator upgrading through rewinding; (3) turbine upgrading through runner replacement; and (4) operational improvements through better coordination of upstream and downstream plants, increasing hydraulic head, and computerization. The Commission encouraged all licensees to examine their projects and propose any efficiency modifications that could contribute to the nation's power supply.

The Commission announced a spring conference to discuss and obtain comments on methods to address environmental protection at projects while allowing for increased generation. The Commission asked commenters to consider: (1) methods for agency involvement; (2) ways to handle and expedite Endangered Species Act consultation; (3) criteria for modifying licenses; and (4) processes to provide efficiency upgrades.

Comments

Greater Operating Flexibility

SWRCB, CPUC, GPU, PG&E, and PPL support the Commission's effort to increase hydroelectric power generation consistent with protecting environmental

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[57]Of the 326 projects licensed by the Commission within the WSCC, 200 projects have provisions that limit operational flexibility and represent a total capacity of 21,000 megawatts.

resources. However, the California Resources Agency and the Hydropower Reform Coalition (HRC) contend that increased hydropower generation may not provide meaningful supply benefits in the context of the overall supply mix, and that other variables and sources of supply will have a greater effect on the ability to avoid blackouts.

EEI supports greater operating flexibility when supplies are constrained and emphasizes that such flexibility should continue as long as a shortfall in supply persists. EEI asserts that during supply shortages the Commission should authorize efficiency upgrades without requiring consultations or license amendments. NHA makes a similar suggestion, proposing that the Commission adopt a standard article in all licenses in the affected region that would allow operational modifications during generation emergencies without going through a time-consuming license amendment process.

PacifiCorp and SCE identify a number of areas for increased generation through capacity increases and operational efficiency upgrades. Shasta Paddlers asserts that improvements can be made by retrofitting the facilities without compromising fish and aquatic resources downstream. NHA asked its members to evaluate the potential for efficiency improvements and capacity additions in their projects, and to provide suggestions at the spring conference referenced in the Commission's order.

Several commenters express apprehension about the environmental implications of the proposal to increase generation through efficiency and operational changes at hydropower facilities. They assert that these measures are likely to have adverse environmental effects and will come at the expense of fish, wildlife, and recreational opportunities. HRC contends that the proposal to increase generation in this manner runs counter to the balancing that the Commission is legally required to give power and non-power resources.

Some commenters encourage the Commission to seek operational improvements that do not compromise the environment. American Whitewater contends that this can be achieved if certain measures such as retrofitting are taken. The California Resources Agency notes that the Commission should encourage mechanical and technological improvements to hydropower projects that would increase generation without further degrading the environment. Trout Unlimited urges the Commission, in examining opportunities for increasing generation, to carefully balance power and environmental values in regard to projects with pre-1986 licenses (i.e., before enactment of the Electric Consumers Protection Act of 1986, which required the Commission to give equal consideration to developmental and environmental values).

GPC and Avista maintain that there are ways to increase power generation during this emerging energy crisis that would be consistent with environmental protection. GPC recommends that during the crisis the Commission lift all restrictions related to recreation. Avista supports NWPPC's recommendation to significantly reduce spill.

The U.S. Department of the Interior recommends that the Commission develop license-specific data on how much improvement in generation, delivery, and reliability can be achieved, and that the two agencies work together to assess costs and benefits.

Potential Project Improvements

Several commenters express concerns about the length of the licensing and amendment processes and encourage the Commission to put hydroelectric case processing on a fast track, both in order to solve the current energy shortage and on a going-forward basis. EEI views the current licensing and amendment processes as complex, time-consuming and costly, and suggests ways the Commission can streamline and improve the hydro licensing process. NCPA and NHA assert that the Commission's policies and licensing process have precluded the fuller utilization of the power potential of hydro projects, and argue that expediting pending relicensing cases and implementing policies to encourage installation of new capacity will provide greater benefits than will any other measure. NHA recommends that the Commission temporarily modify its regulations to expedite the approval of applications for adding generating capacity to aid in the western electricity crisis. LPPC and the Grant County PUD endorse the NHA proposal for a temporary standard license condition as a means of expediting the review process for modifications to existing projects.

Metropolitan Water applauds the Commission's commitment to expeditiously process hydroelectric facility applications and recommends that the Commission eliminate, or at least reduce, the extensive consultation process. HRC proposes an 8-step approach to implementing project improvements that will not harm the environment.

SCE and Avista assert that modifications to existing hydropower projects to add generation or the construction of new projects will not occur in sufficient time to address the short-term supply issues in the western states.

PacifiCorp encourages the Commission to collaborate with state and federal agencies to address license modifications and believes that the Commission could provide greater assistance to licensees for Endangered Species Act consultations.

The U.S. Forest Service maintains that it is committed to participation in licensing proceedings for all Commission licensed projects that affect National Forest Service System lands, and requests permission to implement direct cost recovery from licensees and applicants for licenses.

Commission Response

The Commission's March 14 Order called for Commission staff to hold a conference with licensees and interested stakeholders to discuss methods for allowing increased generation at hydropower projects while ensuring environmental protection.

By notice issued on March 26, 2001, the Commission staff announced that they would hold conferences in Portland, Oregon, and Sacramento, California on April 9 and 10, respectively. To ensure that potential attendees represented a broad spectrum of interests, over 450 notices where sent to licensees, state and Federal resource agencies, Native American tribes, and nongovernmental organizations. During the conferences, Commission staff set forth suggestions as to how proposals to increase generation could be processed. In addition, staff suggested criteria that could be used in identifying proposals that would be consistent with protecting environmental resources.

The Portland conference was attended by approximately 50 individuals, representing all of the aforementioned stakeholder groups. The discussions evidenced a willingness on the part of state and Federal resource agencies to review proposals from the hydropower industry to increase generation. These entities noted, however, that, given the number of endangered fish species in the Northwest, the number of proposals to increase generation may be limited. Similarly, industry representatives, while setting forth suggestions as to how additional generation could be accomplished, also expressed concerned regarding potential impacts to listed species. Some industry representatives said that for projects undergoing relicensing, they were hesitant to divert agencies and other participants from that process in order to pursue interim operational changes. Commission staff urged the industry to re-examine their projects in concert with other stakeholders to determine what opportunities exist to increase generation.

The Sacramento conference was attended by more than 80 individuals representing all principal stakeholder groups. The industry indicated that they were in the process of identifying proposals that could provide for more generation at existing projects, and that they were already or would be engaging the various stakeholders in this review. Due to the power emergencies in California, many of the resource agencies have established programs for quick review of proposals to increase generation. Many of the attendees offered suggestions on how to handle such proposals.

Subsequent to the conferences, a number of industry representatives advised staff that the Commission would soon be receiving several proposals. On May 8, 2001, the Commission granted proposals from Idaho Power Company to waive minimum flow requirements at its Milner and Twin Falls Projects for one year.[58] Currently, the Commission has before it proposals from Public Utility District No. 1 of Chelan County, Washington[59] and Public Utility District No. 2 of Grant County, Washington.[60] The Commission is evaluating all such proposals on a case-specific basis.

IV. <u>Oil Pipelines</u>

Recognizing that some generators rely on oil and oil products for electric generation in the West, the March 14 Order stated that the Commission would explore with oil pipelines whether any innovative proposals could help ensure an adequate flow of petroleum product into Western markets. In addition, the Commission requested comments addressing whether the possible non-delivery of oil products to generators that rely on such products is a serious concern.[61] No substantive comments were filed. The Commission will continue to monitor whether actions need to be taken to facilitate the use of oil and oil products for electric generation in the West.

<u>The Commission orders</u>:

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[58] <u>See</u> 95 FERC ¶ 61,180 (2001), 95 FERC ¶ 61,181 (2001) (both entitled Order Authorizing Temporary Increase in Generation in Light of Electricity Exigencies in Western United States).

[59] Public Utility District No. 1 of Chelan County, Washington proposes to increase the maximum normal reservoir elevation at its Rocky Reach project for a period of one year. <u>See</u> Project No. 2145-041.

[60] Public Utility District No. 2 of Grant County, Washington requests temporary variance of interim spill requirements at its Priest Rapids project. <u>See</u> Project No. 2114-091.

[61] The March 14 Order recognized that oil pipelines rely upon electricity for pumping and to the extent pumping is affected by electric curtailments, oil products may not get delivered to generators that rely on such products.

(A) The actions ordered in the March 14 Order are reaffirmed.

(B) Requests for equity returns and accelerated depreciation for electric transmission facilities consistent with the discussion in the body of this order will be permitted, and limited section 205 rate filings to implement these returns will be allowed.

(C) Temporary waivers of blanket certificate regulations for natural gas facilities are granted consistent with the discussion in the body of this order, and costs associated with such facilities will be permitted to be rolled in.

(D) The petition for rehearing by NRECA and APPA is hereby dismissed.

By the Commission. Commissioner Massey concurred with a
separate statement attached.

(S E A L)

David P. Boergers,
Secretary.

Attachment A

Motions to Intervene, Notices of Interventions, Comments and Protests
Docket No. EL01-47-000

American Electric Power System (AEP)
American Public Gas Assoc. (APGA)
American Rivers, Inc. (American Rivers)
American Superconductor Corp. (AMSC)
American Whitewater Affiliation (American Whitewater)
Arizona Corporation Commission (ACC)
Avista Corp. (Avista)
California Cogeneration Council (CCC)
California Dept. of Water Resources (California DWR)
California Electricity Oversight Board (Oversight Board)
California Energy Commission (CEC)
California Independent System Operator (California ISO)
California Municipal Utilities Assoc. (CMUA)
California Public Utilities Commission (CPUC)
California Resources Agency (Resources Agency)
California State Water Resources Control Board (SWRCB)
Calpine Corp. (Calpine)
Cities/M-S-R (Redding, California; Santa Clara, California; Palo Alto, California and M-S-R Public Power Agency)
Cogeneration Association of California (CAC)
Consolidated Edison Co. of New York (ConEd) and Orange and Rockland Utilities, Inc. (O&R)
Coral Energy Resources, L.P. (CER)
Douglas County Public Utilities District No. 1
Duke Energy Corp. (Duke)
Dynamis Inc. (Dynamis)
Dynegy Power Marketing, Inc. (Dynegy)
Edison Electric Institute (EEI)
Electric Power Supply Association (EPSA)
El Paso Western Pipelines (El Paso Natural Gas Co., Mojave Pipeline Co., Colorado Interstate Gas Co., Wyoming Interstate Co., Ltd.)
Energie Azteca & Energia de Baja (InterGen)
Enron Interstate Pipelines (Enron)

Georgia Power Co. (GPC)
Hydropower Reform Coalition (HRC)
Idaho Power Co. (Idaho Power)
Idaho Public Utilities Commission (IPUC)
Independent Energy Producers Assoc. (IEP)
Indicated RTO West Filing Utilities (Avista, BPA, Idaho Power, Montana Power Co., PacifiCorp, Portland General Electric Co. and Puget Sound Energy, Inc.)
Industrial Consumers (Electricity Consumers Resource Council, American Iron and Steel Institute, American Chemistry Council and American Forest and Paper Assoc.)
Industrial Customers of Northwest Utilities (ICNU)
Kern River Firm Customer Group (Kern River)
Kinder Morgan Pipelines (Natural Gas Pipeline Co. of America, Kinder Morgan Interstate Gas Transmission, LLC)
Large Public Power Council (LPPC)
Mason and Karen Flagg
Metropolitan Water District of Southern Ca. (Metropolitan Water)
Modesto Irrigation District (MID)
Morgan Stanley Capital Group, Inc. (MSCG)
National Energy Marketers Assoc. (NEM)
Natural Gas Supply Assoc. (NSGA)
National Hydropower Assoc. (NHA)
National Marine Fisheries Service (NMFS)
National Oceanic and Atmospheric Administration (NOAA)
National Rural Cooperative Assoc. (NRECA) & American Public Power Assoc. (APPA)
Northern California Council Federation of Fly Fishers (NCCFFF)
Northern California Power Agency (NCPA)
Northwest Industrial Gas Users (NWIGU)
Northwest Power Planning Council
PacifiCorp
Pacific Gas &Electric Co. (PG&E)
Pinnacle West Cos. (Pinnacle West Capital Corp., Arizona Public Service Co., Pinnacle West Energy Corp.)
PPL EnergyPlus & PPL Montana, LLC (PPL Parties)
Portland General Electric Co.
Public Power Council (PPC)
Public Utility District No.2 of Grant County, Washington (Grant PUD)
Public Utility District No. 1 of Snohomish County, Washington (Snohomish PUD)
Qualifying Facilities Lenders Council
Questar Pipelines Company (Questar)

R.M. Gardner
Railroad Commission of Texas (RRC)
Reliant Energy Power Generation, Inc. (Reliant)
Ridgewood Power, LLC (Ridgewood)
Salt River Project Agricultural Improvement and Power District (SRP)
San Diego Gas and Electric Co. (SDG&E) and Southern California Gas Co. (SCG)
San Joaquin Paddlers
Seattle City Light Dept. (Seattle)
Shasta Paddlers
Southern California Edison Co. (SCE)
Southern Cities (Cities of Anaheim, Azusa, Banning, Colton and Riverside, California)
Sunray Energy, Inc. (Sunray)
Tractebel Power, Inc. (TPI)
TransAlta Corp.
Transmission Agency of Northern California (TANC)
Trout Unlimited, Inc. (TU)
United States Department of the Interior
United States Executive Agencies (USEA)
USDA Forest Service
Washington Utilities and Transportation Commission (WUTC)
Western Area Power Administration (WAPA)
Western Carolina Paddlers (WCP)
Williams Companies, Inc. (Williams)
Wyoming Public Service Commission (WPSC)
Xcel Energy, Inc. (Xcel)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Removing Obstacles To Increased Electric Generation And Natural Gas Supply In The Western United States

Docket No. EL01-47-000 and EL01-47-001

(Issued May 16, 2001)

MASSEY, Commissioner, *concurring*:

I support the measures regarding energy supply that today's order adopts. Regarding electricity, these measures include: extending and broadening temporary waivers of QF standards; facilitating market based rate authority for sales from back up and self generation at business locations; authorizing customers to "sell" load reduction at wholesale and at market based rates; facilitating wholesale contract changes to allow demand side management and facilitating demand side cost recovery in wholesale contracts. Many of these same actions were authorized by the Commission last year in our May 2000 reliability initiative. They were good ideas last year and they are good ideas now. I also support the natural gas and hydroelectric measures in today's order.

Most experts seem to agree that the nation's electric transmission infrastructure is inadequate. I share their concern. The impediments to increasing transmission most often mentioned are difficulty getting facilities sited and inadequate returns. I believe that the Commission must take reasonable steps to address these problems, to the extent of our jurisdiction. I support the Commission allowing fully compensatory risk-based returns on equity that are sufficient to attract needed new transmission investment. We do so for gas pipelines and we should do so for electric transmission.

My concern with rate of return premiums for certain transmission facilities adopted in today's order is that there is no particular rationale for the level of returns, which could be as high as 13.5%. In addition, Order No. 2000 reserved such incentive treatments for transmission facilities within RTOs. Nevertheless, because there is an energy emergency in the West, and we want to do all we can to help, I am willing to vote for this approach in these unique circumstances.

I must also express my ongoing concern with the Commission's refusal to consider uniform interconnection standards as suggested by some commenters in this proceeding. While I agree that this proceeding may not be the appropriate forum to consider uniform standards, I renew my call for the Commission to do so in another proceeding. Utility-specific procedures have their idiosyncracies. Electricity markets are regional in scope

and the decision of a new generator to locate in one area or another should be driven by economics, not the relative peculiarities of the interconnection procedures of individual transmission providers.

For the above reasons, I concur with today's order.

William L. Massey
Commissioner