Assessment (FEA). The project is located on Ketchikan Creek and Granite Basin Creek, near the City of Ketchikan, in Ketchikan Gateway Borough, Alaska. The project uses lands administered by the U.S. Forest Service in the Tongass National Forest. The Forest Service is a cooperating agency on this environmental assessment. The FEA contains the staff's analysis of the potential environmental impacts of the project and concludes that licensing the project, with appropriate environmental protective measures, would not constitute a major federal action that would significantly affect the quality of the human environment.

Copies of the FEA are available for review in the Public Reference Room, Room 2A, of the Commission's offices at 888 First Street, NW., Washington, DC 20426. This FEA may also be viewed on the web at http://www.ferc.fed.us/online/rims.htm (please call (202) 208–2222 for assistance). For further information, contact Charles Hall at (202) 219–2853.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 00–13010 Filed 5–23–00; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EL00–75–000]

Notice of Interim Procedures To Support Industry Reliability Efforts and Request for Comments

May 17, 2000.

As the electric industry prepares for another summer of potentially high peak demands, the Commission believes it is important to identify practical steps the Commission and others can take to support the industry's efforts to ensure the continued reliability of the electric power system.[1] Accordingly, the Commission hereby announces a number of specific actions it will implement on an interim basis this summer, and requests comments on these and other actions the Commission could take to assist others in their efforts to address system reliability this summer.

Background

While the Commission does not have direct responsibility over reliability matters, its consistent policy has been to assure that the exercise of its ratemaking and other jurisdictional responsibilities supports and facilities the continued high degree of reliability that has existed in the U.S. Indeed, transmission system reliability is one of the principal issues sought to be addressed by the Commission's recent rulemaking on Regional Transmission Organizations.[2] The Commission has also been monitoring the functioning of electricity markets and has been encouraging good utility practices through its Enforcement Hotline and other programs.

Our objective is not to become involved in the day-to-day operation of the electric grid or to duplicate or supplant the efforts of others in the industry that are engaged in inquiries about electric reliability issues. However, it is important that the Commission exercise its regulatory mandate in a manner that supports, and does not impede, efforts to enhance reliability throughout the industry. The Commission has identified five actions that it can take, in exercising its regulatory responsibilities, that may provide such support this summer by, for example, supporting efforts to increase generation supply, supporting efforts to implement demand-side management, and supporting efforts to maximize the amount of Available Transmission Capability (ATC) this summer. In addition to these actions, the Commission will be expediting individual cases affecting reliability planning for this summer which are pending before the Commission in other dockets.

Actions Commission Will Implement During the Summer of 2000

The Commission hereby announces the following actions that it will implement to support the electric industry's efforts in dealing with reliability issues this summer. Although these actions are within the Commission's authority to implement on an immediate basis and will be in effect on an experimental basis from the date of this Notice through September 30, 2000, we invite comments on them.

1. There are many businesses that have installed generators at their business location to meet a portion of their own demands or to serve as a backstop to their purchase of electricity from the local grid. These generators may provide a ready source of generation capacity during periods when power markets are facing a temporary generation shortage. Indeed, we recently approved a tariff under which the owners of such generation could sell electricity to a power marketer in *InPower Marketing Corporation*.[3] In order to facilitate the use of existing on-site generators to meet demand, the Commission will adopt a streamlined regulatory procedure to accommodate sales from such facilities to any entity engaged in sales of electric energy. Owners of generating facilities located at business locations and used primarily for back-up for self-generation, who would become subject to the Federal Power Act by virtue of sales of power from such facilities,[4] will be permitted to sell power at wholesale from such facilities to non-affiliated entities without prior notice under section 205 of the FPA. Pursuant to FPA section 205(d), we find good cause to waive the prior notice requirements for such sales. Further, the Commission hereby grants waiver of its regulations consistent with our recent orders on market-based rates,[5] and authorizes market-based rates during the identified time period, subject to the following requirements: The wholesale purchasers

[1] We note that other governmental and industry sources share a heightened awareness to current reliability issues. *See, e.g.,* Report of the U.S. Department of Energy's Power Outage Study Team, Findings and Recommendations to Enhance Reliability from the Summer of 1999, at S–1, S–2 (March 2000) (''the reliability events of the summer of 1999 demonstrated that the necessary operating practices, regulatory policies, and technological tools for assuring an acceptable level of reliability were not yet in place''); Investigation Into The Adequacy and Availability of Electric Power (Pub. Util. Comm. of Ohio, Case No. 00–617–EL–COI, April 10, 2000) (Ohio Commission notes that ECAR is predicting a tight capacity situation this summer); High Temperatures & Electricity Demand: An Assessment of Supply Adequacy in California Trends & Outlook (July 1999) (California Energy Commission staff report showing decreasing reserve margins); Northwest Power Planning Council, Pacific Northwest Power Supply Adequacy/Reliability Study (February 2000) (24 percent probability of being unable to serve winter loads by 2003).

[2] Regional Transmission Organizations, Order No. 2000, 65 FR 809 (2000), FERC Stats. and Reg. ¶ 31,089 at 30,997–99 (1999), *order on reh'g,* Order No. 2000–A, 65 FR 12,088 (March 8, 2000), FERC Stats. and Regs. ¶ 31,092 (2000).

[3] Order Accepting For Filing Proposed Market-Based Rate Schedule And Granting Waivers, 90 FERC ¶ 61,329 (2000) (*InPower*).

[4] We note that while entities become ''public utilities'' subject to the Federal Power Act when they commence the sale of electric energy at wholesale in interstate commerce, they cease to be public utilities when such sales cease (assuming they engage in no other activities that would make them public utilities) without further Commission action. *See* Century Power Corporation, 72 FERC ¶ 61,045 at 61,279 (1995).

[5] *See, e.g., InPower,* 90 FERC at 62,105; Reliant Energy, Inc., *et al.,* 91 FERC ¶ 61,073 at Appendix B (2000). The Commission has generally waived for such sellers the following parts of its regulations in 18 CFR: 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 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).

of power from such facilities must 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.[6] To minimize the number of required reports, the purchaser may make one report for all purchases through September 30, 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 third calendar quarter of 2000. If the purchaser does not otherwise file quarterly transactions summaries, it should file this report with the Commission by October 31, 2000.[7]

2. There may be opportunities during the upcoming summer for public utilities to make demand-side arrangements with their wholesale customers. For example, some wholesale requirements customers may have the ability to enter arrangements with their own retail customers to reduce load or obtain power from an industrial generator. Or, a partial requirements customers may have access to generating capacity on its own system. We want to ensure that public utilities will be able to work with their customers to negotiate mutually beneficial arrangements on short notice should the need arise during periods of peak summer demand or should other events occur that affect system reliability. Since time may be of the essence as these opportunities are discovered and negotiated, we find good cause to waive the FPA's prior notice requirement for any rate schedule amendments that may be required to effect these types of arrangements. Thus, to the extent a mutually agreeable DSM alternative changes the terms and conditions of a contract within our jurisdiction, we will grant waiver of the filing of prior notice of the change. By October 31, 2000, the public utility supplier must amend the filed rate schedule. The filing must consist of a report containing the following information: 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.

3. While most power sales are currently transacted under market-based rates, there are occasions when utilities continue to operate under cost-based rates. Often, these cost-based rate 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. During periods of generation shortage, some utilities may be in a position to engage in DSM transactions with their wholesale and retail requirements customers in order to free up capacity for resale to neighboring utilities. These transactions will not take place unless any DSM expenditures can also be recovered under the rate formula, as are all other out-of-pocket costs. However, most rate schedules define out-of-pocket or incremental cost in terms of expenses incurred to generate power, rather than costs incurred to compensate a preexisting customer to reduce load. A few jurisdictional utilities have amended their cost-based pricing formulas to recognize the fact that DSM costs are a form of out-of-pocket or incremental cost.[8] In order to eliminate any disincentive to rely on DSM as a source of supply during generation shortages, we clarify that DSM costs should be treated consistently with all other types of incremental and out-of-pocket costs.

4. In prior orders, we have noted that the deductions from ATC to reflect reliability needs (Capacity Benefit Margin or CBM) can often be reduced in the near-term as the transmission provider gains certainty as to whether the assumptions underlying the CBM computation have, in fact, materialized.[9] The Commission takes this opportunity to remind transmission providers that they are required to reassess CBM assumptions for the current period and determine whether they have, in fact, materialized, *e.g.*, load, temperature and generation outages.[10] Another element of the ATC calculation is the Transmission Reliability Margin (TRM), *i.e.*, transmission capacity that is set aside to account for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.[11] Since the assumptions underlying TRM calculations similarly become more certain in the near-term, we expect transmission providers to engage in the same periodic reassessment of TRM needs. Any changes in CBM and TRM must, of course, be reflected in recalculated ATC. By keeping both CBM and TRM set-aside values up to date, OASIS postings will be more accurate. Accurate ATC is crucial to facilitating power sale transactions that can relieve stresses on the Nation's electric systems.

5. The Commission will be responsive throughout the summer period to suggestions and questions regarding actions that relate to electric system reliability. The Commission is directing its staff to assist with regulatory questions related to practical ideas about what the Commission can do to support the electric industry's efforts with respect to reliability issues. The Commission staff, including the Hotline staff, will be available to respond to questions and suggestions in this regard.

Actions Others Could Take

There are likely other actions that could be taken, either by industry participants or state regulators, that could alleviate potential reliability problems during this summer. These include using demand-side management and applying market mechanisms to stimulate demand-side response; eliminating any regulatory disincentives to customers' integrating on-site supply and demand solutions; promoting energy efficiency; and improving coordination and preparation for electricity emergencies.[12] Where the Commission does not have a direct role in such matters, we seek suggestions from state authorities and industry organizations as to how we could assist in these, or other, areas.

Request for Comments

The Commission seeks the views of industry participants, organizations, and state regulatory authorities on the actions identified herein and on identifying what other short-term measures the Commission and others could take to alleviate reliability stress during peak periods.

For example, in the short term, are there any Commission regulations that

[6] Although we are asking all wholesale purchasers who seek to take advantage of these special procedures to file these reports, it is not our intent to assert jurisdiction over any wholesale purchaser who is not otherwise subject to our jurisdiction, and the submission of such reports will not alter a purchaser's jurisdictional status.

[7] These streamlined procedures are offered as an option. Any jurisdictional seller may also follow standard filing requirements if desired.

[8] *See, e.g.,* Wisconsin Electric Power Company, Docket No. ER99–2180–000.

[9] Capacity Benefit Margin in Computing Available Transmission Capacity, 88 FERC ¶ 61,099 (1999) (*CBM Order*).

[10] *CBM Order* at 61,237.

[11] NERC White Paper, *Transmission Capability Margins and Their Use in ATC Determination*, 4 (June 17, 1999).

[12] We also understand that the National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Electric Reliability has various projects underway that are looking into such matters as distribution system vulnerability to summer heat and peak loading, and interconnection of distributed generation.

the Commission should consider waiving to facilitate electricity commerce during periods when electricity markets are stressed? Can the Commission do more in the short-term to facilitate interconnections? We note that the Public Utilities Commission of Ohio has opened an inquiry into the readiness of its electric utilities to respond to higher demands for electricity this summer.[13] Is there anything the Commission should do to support such efforts?

In addition, while our request for comments is directed primarily toward interim initiatives to alleviate reliability concerns for this summer, would it be useful for the Commission to convene a public conference later in the year to discuss longer-term initiatives relating to electric system operation during peak demand periods? Are there longer-term initiatives that the Commission should consider, such as initiating a review of regional market rules with the goal of clarifying aspects that are ambiguous? The Commission is interested in hearing from such organizations as state regulatory authorities, trade groups, independent system operators, and the North American Electric Reliability Council as to what longer-term measures they or the Commission should consider to deal with reliability stresses.

We request that any comments on short-term interim measures be submitted to us by June 2, 2000. Such comments should be concise and specifically focused on either the specific actions implemented in this Notice or other specific actions capable of being accomplished in the short term. We request that any comments on longer-term initiatives or actions be submitted to us by June 30, 2000. Interested persons should submit an original and 14 copies of any comments to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, and should reference Docket No. EL00–75–000.

The Commission orders:

(A) For entities meeting the qualifications set forth in Paragraph 1 of this Notice, and who satisfy the reporting requirements set forth in that Paragraph, the following advance waivers and authorizations are hereby granted for the period beginning the date of this Notice until September 30, 2000:

(1) The prior notice requirement of section 205 of the Federal Power Act is hereby waived.

(2) Waiver is hereby granted for Parts 35, 41, 101, and 141 of the Commission's regulations.

(3) Authorization is hereby granted to issue securities and assume obligations and liabilities, provided that such issue or assumption is for some lawful object within the corporate purposes of the eligible entities, compatible with the public interest, and reasonably necessary or appropriate for such purposes.

(4) The full requirements of Part 45 of the Commission's regulations, except as noted, are hereby waived with respect to any person now holding or who may hold an otherwise proscribed interlocking directorate involving any eligible entity. Any such person instead shall file a sworn application providing the following information:

(a) full name and business address; and

(b) all jurisdictional interlocks, identifying the affected companies and the positions held by that person.

(B) The prior notice requirement for rate schedule changes described in Paragraph 2 of this Notice is hereby waived, conditioned on the public utility complying with the filing requirements set forth in that Paragraph.

By direction of the Commission. Commissioner Hebert concurred with a separate statement attached.

Linwood A. Watson, Jr.,

Acting Secretary.

Notice of Interim Procedures To Support Industry Reliability Efforts and Request for Comments

[Docket No. EL00–75–000]
Issued May 17, 2000.

HEBERT, Commissioner, *concurring*

I certainly agree with my colleagues that the Commission's actions should promote the continued reliability of the electric power system. And I agree that the Commission should take affirmative steps, to the extent consistent with its jurisdictional authority, to enhance the reliability of the system this summer and future summers. Because today's notice does not appear to hurt our reliability efforts, and might offer some slight marginal benefit, I concur with its issuance.

But I write separately to lament the lost opportunity this notice represents. Unfortunately, the Commission today offers little that will significantly enhance the reliability of the electrical grid. The Commission could be doing so much more to address the perceived problem. All today's notice actually accomplishes is to announce that the Commission is doing its job, and deflect blame for any disruptions this summer to Congress. In my judgment, any blame should be directed at this Commission for not taking decisive action last summer and two summers ago, and in all previous seasons, to promote capital investment in our energy infrastructure and new entry into emerging competitive markets.

I find peculiar the timing of today's notice. In the 2½ years I have served as Commissioner, the Commission has refrained from moving too ambitiously and directly into the reliability arena. I have admired the Commission's restraint. For example, the Commission admirably resisted the temptation to demonstrate its regulatory muscle in responding to the Midwestern ''price spikes'' during the summer of 1998. Despite pleas from some that temporarily high prices suggested a system on the verge of collapse, the Commission resisted the urge to intercede into emerging competitive wholesale markets by, among other things, developing reliability and financial integrity standards.

Rather, the Commission historically has left matters of reliability to the true experts in the field—the North American Electric Reliability Council, the various regional reliability councils around the country, and all affected industry participants. Realizing that the issue of reliability is complex and requires intimate familiarity with local facilities and institutions, the Commission historically has left this matter to industry-led groups, working in concert with all affected stakeholders. The Commission has interceded only when its review of reliability-based practices was necessary to ensure the availability and quality of open access transmission service. Recent orders, such as those addressing the issue of ''tagging'' customer requests for service and the circumstances in which utilities may invoke line loading (i.e., curtailment) procedures when the system is oversubscribed, attest to the Commission's limited role.[1] Another order, involving the Western Systems Coordinating Council, attests to the Commission's willingness to support regional industry and stakeholder efforts to promote mandatory compliance

[13] *See supra* note 1.

[1] *See, e.g.,* Coalition Against Private Tariffs, 83 FERC ¶ 61,015, *reh'g denied,* 84 FERC ¶ 61,050 (1998); North American Electric Reliability Council, 85 FERC ¶ 61,353 (1998), *order on reh'g,* 87 FERC ¶ 61,161 (1999).

(through contracts) with reliability standards.[2]

In my opinion, little operationally has changed to motivate the Commission to take a more activist role on reliability. I suspect the real reason for the Commission's enhanced interest is politics and public opinion. Today's newspapers are ablaze with headlines screaming of looming energy crises and impending blackouts and brownouts. Much of this hysteria, unfortunately, has been fed by the Clinton/Gore Administration. Indeed, in a front page article in the Wall Street Journal, dated May 11, 2000, captioned ''Gloom and Doom: New Rules, Demands Put Dangerous Strain on Electricity Supply,'' the Secretary of Energy is quoted as saying that the United States has ''the grid of a Third World nation.'' [3]

I am not so pessimistic. The United States long has enjoyed the most reliable electrical delivery system in the world. The advent of competitive markets and increasing reliance on competitive forces—rather than command and control regulatory policies—to regulate energy markets do not alter this judgment.

It is true that increased competition, and the emergence of a myriad of market participants and offerings, is placing strains on a electrical network that was not designed for such competitive forces. I agree with the rest of the Commission, as well as Secretary Richardson, that something more should be done to enhance reliability and to avoid unexpected outages. I simply disagree as to the means to accomplish this result.

Today's notice offers various measures intended to promote supply, enhance deliverability, and temper demand. My personal opinion is that offering market-based rates to the owners of on-site generation will introduce precious few megawatts into the interstate grid. Demand-side measures to conserve energy are almost entirely within the purview of the states.[4] Transmission providers already have an obligation to update periodically their calculation and posting of available transmission capability. And Commission staff, identified to ''assist with regulatory questions related to practical ideas'' about reliability, will have limited ability to offer any real help.

My strong preference would be for the Commission, if now inclined to act on reliability, to take decisive action in an area that clearly lies within its existing jurisdiction—the pricing of wholesale power and transmission services. As I have been advocating ever since I first came to the Commission, the Commission has within its jurisdiction the ability to promote reliability—if it really means what it now states. For starters, if the Commission is serious about increasing generation supply, it should act *immediately* to withdraw all price caps in generation markets. I have, unfortunately, written in dissent on many occasions as to the harmful supply effects of price caps.[5] They distort price signals and inhibit entry into competitive markets. By facilitating efforts to minimize short-term price disruptions, and placing regulatory shackles on what should be competitive markets, the Commission is inhibiting precisely the type of investment in the grid that it claims it is now supporting—and that is crucial to assuring true electrical reliability.

Another important means of enhancing reliability is to give transmission providers an incentive to provide reliable, efficient service. Conventional pricing methods provide no such incentive. It is my strong preference to afford utilities some type of performance-based measure of accountability to their customers and their regulators. Consistent with its existing authority, the Commission could—and should—tie earnings and profits to reliability-based and performance-based criteria (such as the number and duration of service interruptions, customer satisfaction, and throughout).

Despite my urgings, the Commission has refused to adopt performance-based pricing measures. I was tremendously gratified when the Commission made its first tentative moves in this direction when it adopted its Order No. 2000 rulemaking on the development of regional transmission organizations. As the Commission explained, a RTO that meets the enumerated characteristics and functions—and that has demonstrated a commitment to promote grid reliability and efficiency—will be eligible for a number of incentives. These incentives include performance-based rates, accelerated depreciation, and return on equity enhancements (formula and risk-based).

While I appreciate the Commission's baby steps on performance-based pricing, it will take awhile for RTOs to develop, win the Commission's approval, and qualify for innovative pricing. If it were up to me, I would adopt pricing measures *now* that would give both regional and individual transmission providers an incentive to minimize or eliminate service disruptions this summer and future summers.

I can think of numerous other measures the Commission can adopt to promote reliability, without delay and without additional authority conferred by Congress. The Commission could afford transcos an additional incentive to build transmission facilities by providing a higher rate of return on transmission assets. The Commission could articulate greater receptivity to proposals to build and invest in merchant transmission facilities. The Commission could pique additional interest in investment and corporate restructuring by allowing acquisition adjustments on the sale of transmission assets that confers benefits on ratepayers.

In addition, the Commission could greatly advance the cause of reliability by indicating its support for stand-alone transmission companies. (In another order on today's agenda, I express serious concern as to the Commission's rejection of the proposed ownership structure for the proposed Alliance transco.) [6] As I have oft-stated, a transco—much more so than any other type of regional institution—has a strong economic incentive to provide reliable and efficient service. I wish the Commission would give a transmission company the chance to operate—and give an unequivocal green light to other utilities that might be considering participation in similar for-profit ventures.

And the Commission—if truly committed to providing supply alternatives—could do much more to promote the development of hydroelectric facilities and the construction of natural gas transmission facilities.[7] The answer to our nation's energy reliability needs lies not in the development of additional regulatory bodies and responsibilities—as the Administration, with the acquiescence of a majority of this Commission, now argues. Rather, the answer lies in

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[2] *See* Western Systems Coordinating Council, 87 FERC ¶ 61,060 (1999).

[3] A Department of Energy report, providing documentation for the Secretary's opinion, is cited in footnote 1 of today's notice.

[4] My experience as a state commissioner shows the difficulty of creating effective DSM programs. I am skeptical of the hasty decision the notice makes on guaranteeing DSM cost recovery.

[5] *See* ISO New England, Inc., 88 FERC ¶ 61,316 at 61,973–74 (1999); California Independent System Operator Corporation, 89 FERC ¶ 61,169 at 61,513–15 (1999); ISO New England, Inc.; New England Power Pool, 90 FERC ¶ 61,170 at 61,555–57 (2000).

[6] *See* Alliance Companies, *et al.,* 91 FERC ¶ ___ (2000).

[7] *See, e.g.,* Independence Pipeline Company, *et al.,* 91 FERC ¶ ___ (2000) (dissenting statement).

promoting policies that encourage capital investment in all types of energy technologies and that allow competitive markets to operate as they should.

I recognize that certain of my suggestions, to some, might fall into the category of ''long-term'' measures that, even if implemented immediately, would not help this upcoming summer. Of course, if the Commission had adopted such reliability-based measures in prior years, it would not have realized the urgency to issue today's notice. And further delay merely exacerbates the conditions identified in the notice. For this reason, I do not see the advantage of differentiating between short-term and long-term fixes, or awaiting the filing of comments on the subject. Nor do I see any value in convening a ''public conference'' on the subject of reliability initiatives. The Commission held such a conference in February of 1998, and has since received numerous comments and pleadings on the topic.

In short, there's not need to await further action by Congress. The Commission already has all the authority it needs to effect real reform that will promote reliable and efficient utility service. And there is no need to delay to allow for further grandstanding by industry participants. By this point, after several summers of experience under competitive markets, we all know the way to promote reliability and efficiency—by encouraging investment and by allowing competitive markets to operate.

Therefore, I respectfully concur.

Curt L. Hebert, Jr.,

Commissioner.

[FR Doc. 00–13008 Filed 5–23–00; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Western Area Power Administration

Proposed Rates for Transmission Service on the Central Arizona Project 115–kV and 230–kV Transmission Lines

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of proposed rates.

SUMMARY: The Western Area Power Administration's (Western) Desert Southwest Customer Service Region (DSW) is proposing rate methodologies to calculate the rates for firm point-to-point transmission service, nonfirm point-to-point transmission service, and Network Integration Transmission Service (NITS) on the Central Arizona Project (CAP) 115–kV and 230–kV transmission lines. The proposed calculated rates will provide enough revenue to pay all annual costs, including interest expense, and repay the required investment within the allowable period. The proposed rate methodologies are scheduled to go into effect on October 1, 2000, and will remain in effect through September 30, 2005. This **Federal Register** notice initiates the formal process for these proposed rate methodologies.

DATES: The consultation and comment period will begin from the date of publication of this **Federal Register** notice and will end August 22, 2000. DSW will present a detailed explanation of the proposed rate methodologies and will make available a rate brochure at a public information forum scheduled for June 16, 2000, beginning at 10 a.m. MST, at the DSW office. Western will receive oral and written comments at a public comment forum on July 17, 2000, beginning at 10 a.m. MST, also to be held at the DSW office.

ADDRESSES: Written comments are to be sent to: Mr. J. Tyler Carlson, Regional Manager, Desert Southwest Customer Service Region, Western Area Power Administration, P.O. Box 6457, Phoenix, AZ 85005–6457, or by e-mail: carlson@wapa.gov. Western should receive written comments by the end of the consultation and comment period to be assured consideration. Western's DSW office, is located at 615 South 43rd Avenue, Phoenix, Arizona.

FOR FURTHER INFORMATION CONTACT: Mr. Maher A. Nasir, Rates Team Lead, Desert Southwest Customer Service Region, Western Area Power Administration, P.O. Box 6457, Phoenix, AZ 85005–6457, telephone (602) 352–2768, or by e-mail: nasir@wapa.gov.

SUPPLEMENTARY INFORMATION: The CAP 115–kV and 230–kV transmission lines have been used almost exclusively to provide power to the CAP water pumps. The planned construction of a number of independent power plants in Arizona and Nevada creates a potential demand for use of surplus transmission capacity on the CAP 115–kV and 230–kV transmission lines.

The proposed rate methodologies for point-to-point transmission service and NITS on the CAP 115–kV and 230–kV transmission lines are based on a revenue requirement that recovers the CAP 115–kV and 230–kV transmission lines costs for facilities associated with providing transmission service and the non-facilities costs allocated to transmission service. The methodology for calculating the rates for point-to-point transmission service on the CAP 115–kV and 230–kV transmission lines is determined by combining the annual amortization costs with the annual operations and maintenance costs, divided by the annual average contract rate of delivery. Implementing the proposed rate methodology results in a firm point-to-point CAP 115BkV and 230–kV transmission line rate of $8.37 per kilowattyear and a nonfirm point-to-point CAP 115–kV and 230–kV transmission line rate of 0.96 mills/kWh.

NITS allows a transmission customer to integrate, plan, economically dispatch, and regulate its network resources to serve its native load in a way comparable to how a transmission provider uses its own transmission system to service its native load customers. The monthly charge methodology for NITS on the CAP 115–kV and 230–kV transmission lines is the product of the transmission customer's load-ratio share times one-twelfth of the annual transmission revenue requirement. The customer's load-ratio share is calculated on a rolling 12-month basis (12CP). The customer's load-ratio share is equal to that customers' hourly load coincident with the CAP 115–kV and 230–kV transmission lines monthly transmission system peak divided by the resultant value of the CAP 115–kV and 230–kV transmission lines monthly transmission system peak minus the CAP 115–kV and 230–kV transmission lines coincident peak for all firm point-to-point transmission service plus the CAP 115–kV and 230–kV transmission lines firm point-to-point transmission service reservations.

The proposed rate methodologies include the costs for scheduling, system control, and dispatch service.

These rate methodologies for transmission service on the CAP 115–kV and 230–kV transmission lines are being set following the Department of Energy Organization Act, 42 U.S.C. 7101–7352; the Reclamation Act of 1902, ch. 1093, 32 Stat. 388, as amended and supplemented by subsequent enactments, particularly section 9(c) of the Reclamation Project Act of 1939, 43 U.S.C. 485h(c); and other acts specifically applicable to the project involved.

By Amendment No. 3 to Delegation Order No. 0204–108, published November 10, 1993 (58 FR 59716), the Secretary of Energy delegated (1) the authority to develop long-term power and transmission rates on a nonexclusive basis to the Administrator of Western; and (2) the authority to confirm, approve, and place into effect