

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

**Preventing Undue Discrimination and )  
Preference in Transmission Service )**

**Docket Nos. RM05-25-000  
RM05-17-000**

**COMMENTS OF THE  
COMMITTEE ON REGIONAL ELECTRIC POWER COOPERATION**

Pursuant to the Commission's Notice of Proposed Rulemaking ("NOPR") issued in the above-referenced dockets May 19, 2006, the Committee on Regional Electric Power Cooperation (CREPC) respectfully files the following comments. In brief:

- CREPC supports reform in the calculation of Available Transfer Capability (ATC).
  - FERC should require that ATC data be accessible, usable and in a consistent format for analysis by regulators and researchers.
  - Flow-based ATC calculations, mechanisms for release and reuse of unused ATC, and real-time ratings should be evaluated.
  - The schedule to develop common ATC procedures for all regions in six months is overly ambitious and should be extended.
- CREPC strongly supports reforms to promote coordinated, open and transparent transmission planning.
  - All transmission owners should be required to develop a biennial transmission plan and this requirement should be incorporated into the reciprocity provisions of the OATT.
  - Transmission owners should be allowed to satisfy these requirements by participating in regional and sub-regional transmission planning.
  - The costs of planning should be equitably shared among transmission owners.
  - FERC should audit planning to identify best practices.

- Data used in planning, including load forecast information, should be transparent and publicly available.
  - An equitable method of financing the reasonable costs of state agencies participating in planning should be established to facilitate timely state action on siting, cost recovery and other regulatory proceedings.
  - Transmission plans should evaluate grid expansion necessary to support future generation options, evaluate transmission options necessary to implement approved or state acknowledged load serving entity resource plans, and evaluate the applicability of new transmission technologies and demand-side options.
  - Regional definitions of “significant and recurrent” congestion should be informed by assessments of historical flows, a comparison of ATC, schedules and actual flows, and an assessment of denied transmission requests. ATC and schedule data should be archived to allow for easy analysis across all transmission owners in an interconnection.
  - FERC should set a lower threshold for determining prudence of transmission planning costs than for project costs.
  - Although desirable, FERC should not mandate an open season approach to transmission expansion.
- CREPC supports reforming imbalance charges consistent with the three principles set forth in the NOPR.
    - More flexibility in the imbalance penalty bandwidth should be allowed for intermittent generators.
    - Changes to schedules should be allowed up to 20 minutes before the hour.
    - The OATT should encourage better wind forecasting by, for example, forecasting in several time horizons.
    - FERC should impose imbalance penalties that relate to actual costs imposed by deviations with appropriate exemptions for intermittent resources.
    - RTOs/ISOs should be encouraged to adopt flexible approaches to imbalances associated with intermittent resources similar to the California ISO’s Participating Intermittent Resource program.
- CREPC supports new long-term transmission service products like redispatch and conditional firm.
    - FERC should not mandate either alternative now. Both products are promising tools that could complement each other in the broader strategy to improve efficiency of the existing grid.

- A clear definition of the attributes of conditional firm service should be developed.
- FERC should hold a technical workshop to vet innovative solutions being developed.
- CREPC supports adding an hourly point-to-point firm service into the *pro forma* OATT.
  - Transmission customers should be allowed to batch requests and schedules within the same day.
  - Differences in the definition of peak and off-peak hours should be allowed.
- CREPC supports reforms to improve the processing of transmission service requests.
  - The disposition of all transmission service requests should be posted quarterly.
  - A separate category should be created for renewable resource transmission requests and studies.
  - Clarification is needed on the NOPR's proposed operational penalties and such penalties should not be imposed on projects crossing seams in the Western Interconnection.
  - Queue blocking behavior should be discouraged and a reasonable fee on "self-competing" transmission services requests is appropriate.
  - A standard for determining "self-competing" requests should be developed.
  - Practices to prevent queue hoarding and queue flooding should be adopted.
  - FERC should review and audit how transmission owners are complying with queuing requirements.
  - Clustering of transmission service requests for studies to encourage the cost-effective execution of studies should be required but transmission owners should have flexibility to develop criteria for clustering requests.
  - The first-come, first served approach for long-term and short-term transmission reservations should be replaced with a broader window for requests than the NOPR proposes.
  - Pre-confirmation of service requests should not trump other factors in determining priority of requests.
  - Open season strategies promote even-handed competition for transmission expansion.

## **I. INTRODUCTION**

CREPC is a joint committee of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners. It was formed in 1983. All regulatory, energy planning and siting agencies in the states and provinces in the Western Interconnection are eligible to participate in CREPC. Positions are taken by CREPC only if no state or province objects. The Western Interstate Energy Board is an organization of 12 Western states (AZ, CA, CO, ID, MT, NE, NV, NM, OR, UT, WA, WY) and three Western Canadian Provinces (AB, BC, SK). Its members are appointed by the Governor or Premier. Its legal basis is an interstate compact approved by 12 states and Congress (PL 91-461). The Board serves as the technical energy arm of the Western Governors' Association. The Western Conference of Public Service Commissioners includes the PUCs from 11 states (AZ, CA, CO, ID, MT, NV, NM, OR, UT, WA, WY).

Each Western state or province may be offering its own responses to the issues raised in the NOPR. CREPC offers the following observations and recommendations that reflect a consensus regional perspective of the states and provinces linked by the Western Interconnection.

The Western Governors' Association (WGA) recently completed the Clean and Diversified Energy Initiative which contemplates adding 30,000 MW of clean and diversified energy in 18 western states by 2015. CREPC participated in this effort. CREPC's comments on this NOPR build, in part, upon the discussions with industry and the WGA task force recommendations that relate to transmission to support new clean and diversified energy resources.

## **II. PROPOSED MODIFICATION OF THE OATT**

### **A. Consistency and Transparency of ATC Calculation**

CREPC strongly supports the Commission's initiative to improve the transparency of Available Transfer Capability (ATC), and generally endorses working towards ATC consistency over time. For the past four years, CREPC and WIEB have called for improved access to and analysis of ATC information.<sup>1</sup> Transparent and usable ATC information will enhance our understanding of transmission operations and guide policy to improve the efficiency of the existing grid.

To date, western state regulators and policy makers have been unable to systematically assess ATC, and compare ATC levels with actual flows on the grid. In 2003, the Seams Steering Group-Western Interconnection (SSG-WI) completed a path flow study that documents historic actual flows on major transmission paths in the Western Interconnection for 1998-2002.<sup>2</sup> SSG-WI and the Western Electricity Coordinating Council (WECC) updated the path flow study in 2006. Figure 1 below summarizes key findings from the 2006 study. The graph ranks 24 major transmission paths according to the percentage of time each path reached 75 percent or more of its Operating Transfer Capacity (OTC) limit during the highest seasonal period (summer, spring, and winter) from 1999-2005. The graph shows that only 6 of the 24 transmission paths, or 25%, experience actual flows at 75% or greater of OTC limits half of the time.

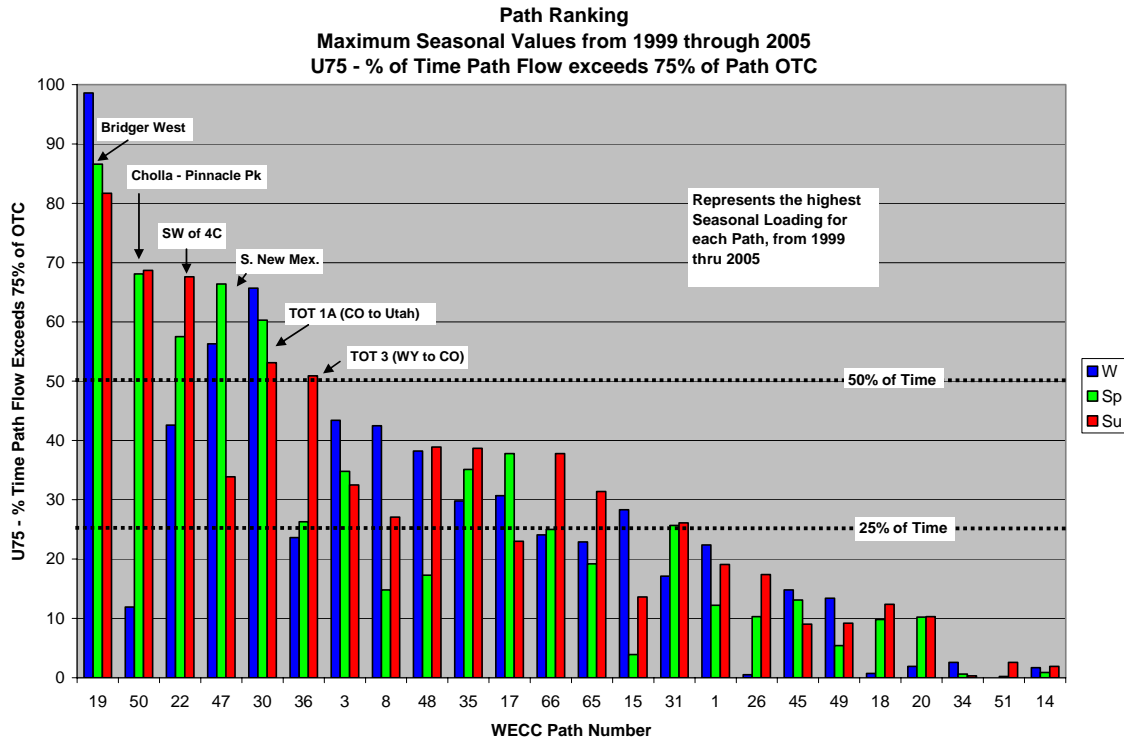
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<sup>1</sup> See Western Interstate Energy Board (WIEB) proposal to the Commission how to investigate the apparent paradox between zero or minimal ATC levels and low historic flows on major western transmission paths, Recommendation to FERC: Assessing the Utilization of Transmission Paths in the Western Interconnection, February 18, 2005; WIEB Comments, Technical Workshop on Assessing the State of Wind Energy in Wholesale Markets, Docket No. AD04-13-000, December 1, 2004; CREPC letter to the Commission recommending analyses of the implementation of Order 888 to inform the Commission on potential improvements. December, 2002.

<sup>2</sup> Seams Steering Group – Western Interconnection, Western Interconnection Transmission Path Flow Study, February 2003.

The data suggests 75% of the transmission paths operate significantly below their physical capacity throughout most of the year.

Figure 1



Researchers conducting the 2006 path flow study attempted to collect ATC data on the same transmission paths and evaluate the relationship of actual flows to ATC for paths. Despite the best efforts of experienced staff over the past year, the project has been unable to compile a consistent data set on posted ATC levels for these paths due to technical difficulties, inconsistent data, and coordination among different entities storing data. Therefore, the current rules and practices are not sufficiently transparent to make important ATC data easily accessible and usable for review by policymakers and regulators.

CREPC requests that the Commission adopt ATC rules that ensure that ATC data be publicly available in a format that is accessible, usable, and in a consistent format for systematic analyses by regulators and researchers.

The Transmission Task Force of the Western Governors' Clean and Diversified Energy Advisory Committee (CDEAC) specifically called on the Commission to "adopt policies to encourage transmission providers to pursue transparent reviews and reasonable assessments ATC levels on their existing transmission paths."<sup>3</sup> The recommendation calls for reviews to evaluate flow based ATC methodology, and consider mechanisms to release or re-use unused ATC, and development of real time ratings.<sup>4</sup>

Improving the institutional process to calculate ATC could yield large gains. Bonneville Power Administration (BPA) recently reviewed its ATC methodology and estimates on numerous key transmission corridors. BPA's findings prompted it to revise its ATC levels upward by more than two thousand aggregate MWs.<sup>5</sup> Following the BPA role model, improved transparency and consistency may yield similar upward revisions of ATC by other transmission providers and expand transmission service availability on the grid.

CREPC notes and applauds recent ATC advances consistent with the Commission's current initiative. WestConnect transmission providers<sup>6</sup> collaborated and

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<sup>3</sup> Report of the Transmission Task Force, Western Governors' Association Clean and Diversified Energy Initiative, May 2006, at 28.

<sup>4</sup> *Id.*

<sup>5</sup> On June 22, 2005, BPA posted revised upward ATC calculations for the following lines by the following amounts: West of McNary (330 MW), West of Slatt (501 MW), North of Hanford (489 MW), North of John Day 776 MW), Allston-Keeler (304 MW), Monroe-Echo Lake (37 MW), Paul-Allston (106), and Raver-Paul (111 MW).

<sup>6</sup> WestConnect parties include Arizona Public Service, El Paso Electric Company, Imperial Irrigation District, Public Service Company of Colorado, Public Service Company of New Mexico, Salt River

developed common ATC definitions and methodology.<sup>7</sup> This effort helps ensure common standards and terminology for transmission services across this sub-regional area.

At the same time, CREPC acknowledges there are complex technical issues associated with calculating ATC. We are concerned that the drive to develop common standards in six months may lead to an overly rigid framework for all regions. We question whether NAESB and NERC can adequately address this issue in such a short timeframe, considering the current agenda for developing reliability standards.

In summary, CREPC strongly supports improving the transparency of ATC calculations, but advocates a more flexible and cautious approach in structuring consistency of ATC given regional variations and complex technical issues.

## **B. Transmission Planning – Coordinated, Open and Transparent Planning**

### Summary

FERC should:

- Require all transmission owners develop a biennial to triennial transmission plan and incorporate this requirement in the reciprocity provisions of the OATT. This requirement could be satisfied by participation in the development of a sub-regional and interconnection-wide transmission plan. All such plans need to be coordinated throughout an interconnection.

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Project, Southwest Transmission Cooperative, Tri-State Generation and Transmission Association, Tucson Electric Power Company, and Western Area Power Administration.

<sup>7</sup> WestConnect Transfer Capability Stakeholder Meetings, Phoenix, AZ, February 1, 2005 and Denver, CO, June 22, 2005.

*Comments of the Committee on Regional Electric Power Cooperation*

- Require that the costs of regional transmission planning should be equitably shared among all transmission owners.
- Conduct audits of transmission owners for the purpose of identifying and publicizing best practices in areas including transparency of data and analysis, the degree of regional participation, and the analysis of congestion.
- Require transparency of information used in transmission planning, particularly load forecasts. Load forecast information available on Form 715 and load forecast information presently used in regional transmission planning in the Western Interconnection is not sufficiently transparent.
- Establish an equitable method of financing of the reasonable costs of state agencies participating in sub-regional and interconnection-wide planning, particularly when those agencies have planning, ratemaking or permitting responsibilities with respect to planning solutions.
- Require transmission plans to:
  - Evaluate transmission expansion necessary to support future generation options that are economically and environmentally viable;
  - Evaluate transmission options necessary to implement the approved or state-acknowledged resource acquisition plans of load serving entities; and
  - Evaluate the applicability of new transmission technologies and demand-side options to relieve congestion.
- Require the development of a regional definition of “significant and recurrent” congestion and the metrics to measure such congestion. The analysis of “significant and recurrent” congestion should include: (a) an assessment of

historical flows on major transmission paths; (b) a comparison of ATC and schedules with historical flows; and (c) an assessment of denied transmission service requests. The Commission should require the archiving of ATC and schedules in a form that allows for easy analysis across all transmission owners in an interconnection.

Below are comments on the proposed eight principles for a coordinated, open and transparent planning process.

1. Coordination

- a. We do not believe that the rule should specify the details of how to achieve the goal of open transmission planning (e.g., number of meetings). Best practices should be identified and documented from information derived from audits. This will provide a sound information basis upon which the Commission can draw conclusions about the level of compliance and entertain any additional changes to the pro forma OATTs.

2. Openness

- a. We concur with the Commission that transmission planning meetings, conference calls and documents should be open to all affected parties including, but not limited to transmission owners, transmission customers, generation developers, interest groups, states and provinces.

3. Transparency

- a. Regarding data to support transmission planning, we urge the Commission to ensure greater transparency by requiring that load forecasts used in

transmission planning be transparent and publicly-available.<sup>8</sup> We concur with the NOPR that Form 715 reporting requirements have not satisfied the need for transparency.

- b. We support a biennial transmission planning reporting requirement which includes:
  - (1) A discussion of interconnection-wide planning results and projects.
  - (2) A discussion of sub-regional planning results and projects, including descriptions of the connections between sub-regional and interconnection-wide planning.
  - (3) A synopsis of state or transmission-owner level planning and projects.  
  
The Arizona Corporation Commission's biennial transmission report is a model for state-level transmission planning reports. See <http://www.cc.state.az.us/utility/electric/BTA-11-30-04.pdf>.
  - (4) A provision that the reporting requirement applied to individual transmission owners can be met by reports of open, transparent sub-regional and interconnection-wide planning bodies.
- 4. Information exchange (no comments)
- 5. Comparability
  - a. We support the proposal that the transmission provider develop a transmission system plan that: (1) meets the specific service requests of its transmission customers; and (2) otherwise treats similarly situated customers comparably in transmission planning.

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<sup>8</sup> CREPC has been seeking greater transparency in WECC data used in transmission expansion planning and resource adequacy assessments. See May 14, 2004 CREPC letter at [http://www.westgov.org/wieb/meetings/crepcfall2004/briefing/CWltrdf\\_5-14-04.pdf](http://www.westgov.org/wieb/meetings/crepcfall2004/briefing/CWltrdf_5-14-04.pdf)

6. Dispute resolution (no comments)
7. Regional participation
  - a. We concur with the Commission that the plans of individual transmission owners be shared to ensure they are simultaneously feasible and use consistent assumptions and data. We also agree that such sharing of plans is essential to identify system enhancements to relieve congestion.
  - b. We concur with the Commission that transmission planning needs to occur at the interconnection-wide level and the sub-regional level, as well as at the transmission owner system level.
  - c. In the Western Interconnection, WECC should be lead institution for interconnection-wide planning and such planning should be closely linked to sub-regional planning being done by the Northwest Transmission Assessment Committee (NTAC), the Southwest Area Transmission (SWAT) study, the Colorado Coordinated Planning Group (CCPG), the Southwest Transmission Expansion Plan STEP), and the Rocky Mountain Area Transmission Study (RMATS).
  - d. Assuming comprehensive requirements in the OATT regarding open and transparent transmission planning and audits to identify and document “best practices”, we do not believe there is a need to mandate the use of a third party to oversight the planning process. However, as was found in the Rocky Mountain Area Transmission Study and has been proposed in the evolving WECC interconnection-wide planning process, a third party to act as

facilitator of stakeholder participation in the planning process can be very effective and should be encouraged.

- e. We concur that the active participation of state regulatory commissions, energy agencies, and facility siting agencies in transmission planning is essential. Such participation will ensure that issues and associated information requirements critical to project cost recovery and to permitting are addressed in the planning process. This will enable more expeditious decisions on issues such as the need for facilities, cost recovery and permitting. In the Western Interconnection, where most load-serving entities develop detailed resource plans, regional transmission planning and load-serving entity resource plans need to be closely linked. At least one evaluation of regional transmission planning should reflect the resource acquisition projects of load serving entities and compliance with state energy policies.
- f. Fiscal limitations too often have precluded effective participation by state agencies in regional transmission planning efforts. Such participation in regional transmission planning is often not a central mandate of state statutes. As the Keystone Center's June 2005 report "Regional Transmission Projects: Finding Solutions" concluded, states lack resources to effectively participate in regional transmission planning.<sup>9</sup> The Commission should consider a

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<sup>9</sup> To be effective participants in regional planning processes, state agencies must have reasonable and predictable funding for such activities as travel to out-of-state regional planning meetings, staff time for verification of load and resource data used in regional transmission planning, participation in regional planning workgroups, and collaboration with neighboring state agencies. States could consider several sources of funding, including: existing state general funds (although the competition for state general fund appropriations would be intense and subject to potential volatility); fees assessed on regulated entities (although relying solely on fees levied to support the activities of public utility commissions would not apply to non-jurisdictional entities); or a surcharge on transmission tariffs that reflect transmission flows

transmission tariff rider to fund state participation in regional transmission planning processes. Such a rider could also be used to fund the centralized costs of regional transmission planning efforts (e.g., modeling cost, meeting costs, facilitators), thereby ensuring equitable allocation of the costs of such planning and eliminating free riders.

8. Congestion studies

- a. We recommend that a regional definition of and supporting metrics for “significant and recurrent” congestion be developed (paragraph 214, #8) in a public process.
- b. We believe that the transmission study process should not be limited to examining reliability and current congestion. Most regional transmission planning in the West has been forward-looking by examining transmission needs at least 10 years into the future that would be necessary to support different mixes of future generating resources.

In response to the Commission’s request for examples of transmission planning processes, we believe that many of the transmission planning processes in the Western Interconnection (WECC, SWAT, CCPG, NTAC, STEP, RMATS) include significant elements of the proposed principles. For example, a common load and resource data base, and common load flow cases have been used in production cost modeling by WECC, STEP and NTAC. This promotes comparability of modeling results. All Western planning meetings are open to all parties and notice is provided for such meetings.

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through control areas or as part of the ISO administrative fees recovered through the ISO tariff. “Regional Transmission Projects: Finding Solutions”, June 2005, p. 4)

We concur with the Commission that a high degree of certainty for the recovery of costs for transmission planning is important. We recommend that the Commission set a lower threshold for determining prudence of investments in transmission planning than for project construction costs.<sup>10</sup>

We believe an open season approach to enable any interested party to participate in a potential transmission project is desirable. However, at least in the Western Interconnection, we do not believe the Commission needs to mandate an open season approach because this objective is largely being met through the typical project development process in the West.

Open transmission planning identifies likely beneficiaries of new transmission capacity. Historically, these parties have joined together to build new transmission projects. The WECC Regional Planning Project Review document<sup>11</sup> provides a process

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<sup>10</sup> Recommendations endorsed by Western Governors as part of their Clean and Diversified Energy Initiative provide: ***Recommendation 11: Presumption of Prudence.*** Governors should urge State regulators to adopt policies, and promote legislation if necessary, to establish a tiered standard of review for prudence and application of transmission incentives for transmission expansion costs featuring a lower standard for screening studies and planning, a moderate standard for permitting and the acquisition of rights-of-way, and a higher standard for construction costs. This tiered standard for review of prudent costs and use of financial incentives will reduce the risk to transmission developers associated with recovering the cost of scoping and planning of potential transmission expansion projects. This will encourage transmission developers to evaluate and plan potential expansion which are, relative to generation costs, low cost investments. States should work together to develop common standards for review of prudent costs and use of incentives.” CDEAC Transmission Task Force Report, May 2006, page 45. See <http://www.westgov.org/wga/initiatives/cdeac/TransmissionReport-final.pdf>

<sup>11</sup> WECC’s document provides that “The Regional Planning Review Process encompasses the initial development phase of a project in which regional interest is expressed. The Process addresses how transmission project sponsors should work and interact with other parties when developing a project that has or may have a significant regional benefit or impact. Through this process, WECC members cooperate to identify transmission expansion projects that may be beneficial to the region. By following this process, project sponsors may also address certain issues related to regulatory approval of their projects. The Regional Planning Review Process should begin as soon as possible and involve all interested project participants. Although it will vary, this phase of the process should start when interested project participants are devising their individual and collective transmission needs. This phase is completed when PCC has made a final determination regarding the project's conformity with the WECC Regional Planning Guidelines.” See

for project sponsors to solicit participation in a proposed project and/or participate in the review of proposed projects. The West has growing experience with open seasons, the most recent being Northwestern Energy's open season for expanding transfer capacity between Montana and Idaho. More can be learned from these processes and the Commission may want to consider developing information on best practices in conducting open season solicitations.

Justification for the Recommendation

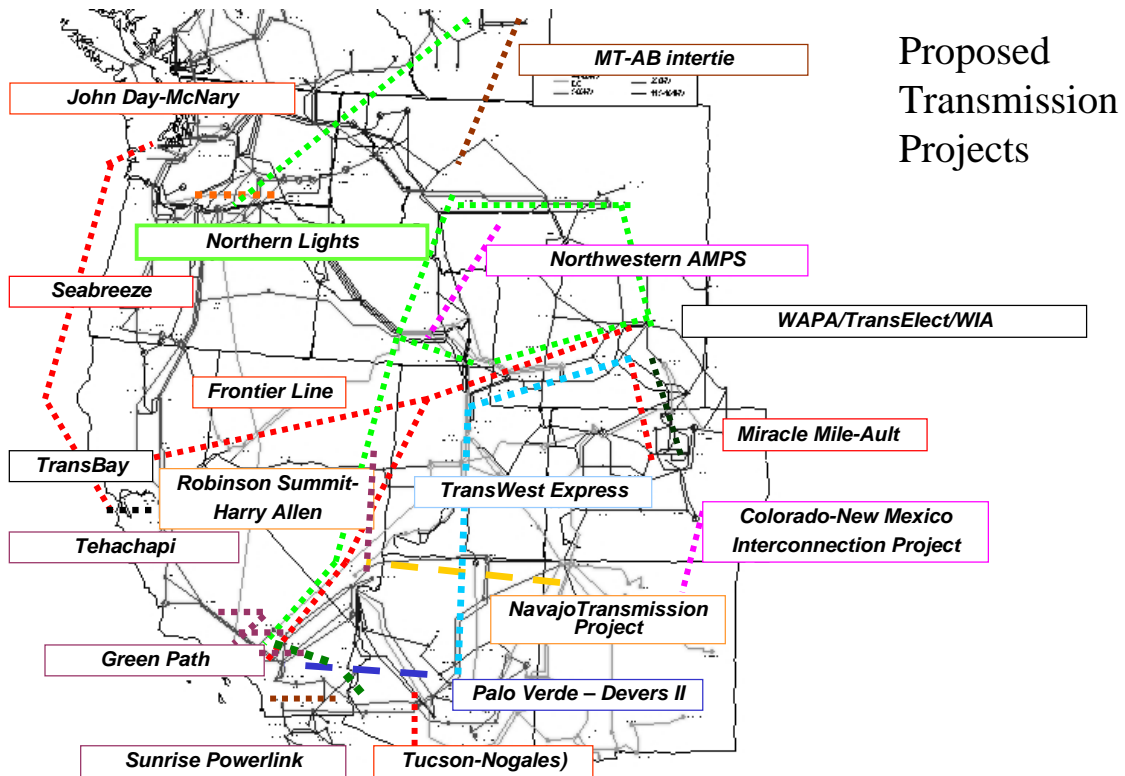
Since the Western electricity crisis, regional transmission planning in the Western Interconnection has been transformed. The concept of open, stakeholder-driven planning has become a fixture in the Western Interconnection. There is significant agreement that the data and assumptions used in such planning need to be public if the planning results are to be given adequate deference in regulatory processes. Much progress has been made to achieve such transparency.

Experience in the Western Interconnection is showing that open transmission planning can lead to proposed projects and ultimately to steel in the ground. This is most evident in Arizona where the Central Arizona Transmission Study (a predecessor to SWAT) has resulted in projects that were built. Good transmission planning builds the foundation for identifying the benefits of transmission expansion and the beneficiaries of such expansions. It provides the analytic information necessary for interested parties to coalesce and to develop project proposals. The net result has been a plethora of transmission proposals in the Western Interconnection. The map below shows many of these proposed projects.

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[http://www.wecc.biz/documents/library/procedures/planning/Overview\\_Policies\\_Procedures\\_RegionalPlanning\\_ProjectReview\\_ProjectRating\\_ProgressReports\\_07-05.pdf](http://www.wecc.biz/documents/library/procedures/planning/Overview_Policies_Procedures_RegionalPlanning_ProjectReview_ProjectRating_ProgressReports_07-05.pdf)

Figure 2



In many cases, interconnection-wide and sub-regional transmission planning has advanced because of an immense contribution of staff resources by a few transmission owners. Too many of the Western transmission planning processes are ad-hoc in nature without a permanent institutional home and without sustained funding. A mandatory transmission planning requirement in Order 888 will help fill these shortcomings without undercutting the significant progress made in developing open, transparent planning in the Western Interconnection.

## **C. Transmission Pricing**

### **1. Imbalances**

CREPC supports the Commission's proposed reforms of imbalance charges. CREPC agrees with the Commission's general assessment of the problems with current rules on energy imbalances and generator imbalances, and strongly endorses the proposed three principles for imbalance schedules.<sup>12</sup>

Current imbalance penalties are a barrier to expanded development of intermittent resources like wind energy in wholesale electricity markets. The existing rules for imbalance penalties were developed in the context of an industry based primarily on thermal generators that have the ability to accurately schedule and control energy output. Those policies are not appropriate in all circumstances because they impose an unreasonable disadvantage on intermittent resources, and undermine the policy objectives to integrate more clean and diversified energy resources into the system.

CREPC agrees that penalties should deter conduct that could threaten system reliability and create incentives to encourage good utility practices. Well designed penalties should influence behavior and be avoidable by customer actions. It is not appropriate, however, to maintain penalties that effectively limit intermittent generator market participation that cannot be reasonably avoided.

CREPC encourages the Commission to build upon its proposed principles with the recommendations of the CDEAC Wind Task Force. The imbalance penalty

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<sup>12</sup> The three imbalance schedule principles are: (1) the charges must be based on incremental cost or some multiple thereof; (2) the charges must provide an incentive for accurate scheduling, such as by increasing the percentage of the adder above (and below) incremental costs as the deviations become larger; (3) the provisions must account for the special circumstances presented by intermittent generators and their limited ability to precisely forecast or control generation levels, such as waiving the more punitive adders associated with higher deviations.

recommendation calls for reforms based on cost-causation principles and on linkage to near-term scheduling and wind forecasting. Specifically,

- First, more flexibility is needed in expanding the current Commission policy of a 1.5% bandwidth for intermittent generator imbalances because the narrow bandwidth imposes an unrealistic constraint for the inherent characteristics of intermittent resources. Widening the band reduces the burden on wind generators and partially increases the challenges on system operators to coordinate other resources. The appropriate deviation bandwidth and pricing structure are interdependent with the parameters of scheduling and wind forecasting.
- Second, transmission providers should abide by the current rule that intermittent generators and other generators are allowed to change schedules up to 20 minutes before the hour. Near term scheduling improves the ability of wind generators to accurately match scheduled energy to delivered energy. Economic theory generally calls for shifting risk to the parties that can best deal with the risk to minimize total social costs. In this case, system operators are better positioned to integrate multiple resource options and minimize total costs.
- Third, wind forecasting is an essential ingredient in the effort to expand wind energy and to improve scheduling and system operations. A desired policy should ensure that wind generators coordinate efforts to support an efficient wind forecasting technology.

- Fourth, tariff structures should be reformed to be in line with ancillary cost studies or cost-causation principles.

Under the fourth principle, imbalance penalties should be linked to generator costs imposed on the system by deviations from scheduled generation. Emerging studies show that wind integration costs range from less than \$1/MWh to nearly \$5/MWh for wind penetrations levels up to 20%. See Figure 3 below. The costs of integration will vary in different systems depending upon factors including the level of penetration, the size of the balancing authority, the mix of generation resources, and wind forecasting and scheduling errors. This range of costs is far below the current maximum allowable imbalance penalty of \$100/MWh.

**Figure 3. Wind Integration Cost Estimates**

Study	Relative Wind Penetration (%)	Regulation \$/MWh	Load Following \$/MWh	Unit Commitment \$/MWh	Total \$/MWh
UWIG/Xcel	3.5	0	0.41	1.44	1.85
PacifiCorp	20	N/A	1.64	3.00	4.64
BPA/Hirst	7	0.19	0.28	1.00-1.80	1.47-2.27
PJM/Hirst	0.06-0.12	0.05-0.30	0.70-2.80	N/A	0.75-3.10
We Energies I	4	1.12	0.09	0.69	1.90
We Energies II	29	1.02	0.15	1.75	2.92
Great River Energy I	4.3				3.19
Great River Energy II	16.6				4.53
CA RPS Phase I	5	0.64	0	N/A	0.64
MN DOC/Xcel	15	0.23	0	4.37	4.60
CO/Xcel	10	0.20	1.26*	2.26	3.72
CO/Xcel	15	0.20	1.45*	3.32	4.97
WAPA**					

*Source: Western Governors' Association's Clean and Diversified Energy Advisory Committee Wind Task Force Report, March 2006, p. 35*

(Notes: \*Cost from natural gas nominations, not load following. \*\*WAPA is in process of developing a new regulation tariff. Information concerning this tariff will be added when available).

In the West, a number of entities have developed alternative approaches to address the issue of imbalance penalties with intermittent resources.<sup>13</sup> CREPC believes that Bonneville Power Administration (BPA) and PacifiCorp approaches provide good role models consistent with incentive structures and cost causation principles.

BPA adopted the Generation Imbalance Service (GIS) that features a three-tiered deviation band structure: 1) Band 1 for deviations less than or equal to 1.5% of the scheduled energy or 2 MW, whichever is larger; 2) Band 2 for deviations between 1.5% and 7.5%, or 2 MW to 10 MW, whichever is larger; and 3) Band 3 for deviations greater than 7.5% or 10 MW, whichever is larger. Imbalances within Band 1 are assessed monthly with a financial settlement based on the applicable average incremental costs for high and low load hours. Imbalances within Band 2 are assessed a +/-10% penalty of BPA's incremental costs for actual generation less/greater than scheduled energy, respectively. Imbalances within Band 3 trigger a +/-25% penalty of BPA's incremental costs for actual generation less/greater than scheduled energy, respectively. BPA exempts wind generation from Band 3. Wind generators are subject to the 10% penalty in Deviation Band 2.

PacifiCorp modified its OATT Schedule 4 with an energy imbalance service that features a 5% bandwidth for deviations from scheduled energy, and penalties based on

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<sup>13</sup> Examples include Bonneville Power Administration (BPA), PacifiCorp, California Independent System Operator Corporation (CAISO), and the Western Area Power Administration ("Western"). BPA and PacifiCorp are discussed above. The CAISO implemented and obtained the Commission approval for its Participating Intermittent Resource Program (PIRP). PIRP exempts wind generators from hourly imbalance penalties in favor of a monthly netting of imbalances combined with a centralized wind forecasting program to coordinate hourly scheduling. Western adopted an imbalance rate for intermittent renewable energy sources with no bandwidth. Western purchases, on a pass-through cost basis, the resource necessary to mitigate the shortfalls inherent in intermittent resources. When generation exceeds the forecast, Western pays for the over delivery. Intermittent resource providers pay only for the energy imbalance service they take, and are not penalized for any out-of-bandwidth activity.

market prices rather than incremental/decremental costs of the transmission provider. PacifiCorp also advocates linking imbalance provisions to requirements that generators use state-of-the-art forecasting technologies.

CREPC supports the incentive effects associated with the three-tiered penalty structure used by BPA. CREPC proposes that intermittent resources should generally be exempted from the punitive third-tier penalties when best practices wind forecasting techniques are utilized in systems operation. Under special hardship conditions, however, balancing authorities may seek a waiver from the exemption of intermittent generators to third-tier penalties. Local state regulators and the Commission must approve the waivers for hardship conditions.

In summary, these alternative approaches that have been developed and implemented in the West provide some excellent models that the Commission should follow as it considers how to revise Schedule 4 of the *pro forma* OATT in a manner that appropriately accommodates intermittent resources like wind energy.

Finally, even though the *pro forma* OATT will not be applicable in control areas where the grid is operated by RTOs and ISOs, the Commission should enunciate a policy in connection with any changes it makes to Schedule 4 that encourages all RTOs and ISOs to adopt a flexible approach for dealing with energy imbalances associated with generation by intermittent renewable resources along the lines of the CAISO's Participating Intermittent Resource Program (PIRP) program.

## **2. Credits for Network Customers**

No comments

### **3. Capacity Reassignment**

No comments

### **4. “Operational” Penalties**

No comments

### **5. “Higher of” Pricing Policy**

No comments

## **D. Non-Rate Terms and Conditions**

### **1. Potential Modifications to Long-Term Firm Point-to-Point Service**

CREPC supports the Commission’s initiative to create new long-term transmission service products like redispatch and conditional firm. CREPC notes that the CDEAC Transmission Task Force Report and the Wind Task Force both endorsed adoption of redispatch and conditional firm type transmission service products.<sup>14</sup> New, innovative transmission products are important tools to promote an efficient utilization of the grid, and to potentially tap significant amounts of new clean and diversified generation resources on existing transmission lines.<sup>15</sup>

The NOPR discussion on modifying long-term point-to-point service describes redispatch service as the superior option over conditional firm service in the context of

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<sup>14</sup> Report of the Transmission Task Force, Western Governors’ Association Clean and Diversified Energy Initiative, May 2006, at 1, 28; Wind Task Force Report, Western Governors’ Association Clean and Diversified Energy Initiative, March 2006, at 2, 49-50.

<sup>15</sup> See CDEAC Wind Task Force, at 18. The Wind Task Force derived supply curves for wind energy under different assumptions about transmission. One case assumed that 20% of the transmission capacity is available with tariff reforms. A second case assumed there is no existing transmission capacity and all new wind generation requires the building of new transmission. The analysis shows that at a price of electricity \$60/MWh, the quantity of wind supplied would be 100 GW in the 20% transmission availability case and approximately 24 GW if new transmission is required for all new wind generation. In other words, reforms that enable 20% more of the existing grid, if available, would yield about 75 GW of new wind generation in the WGA region for the same price of energy.

two mutually exclusive options.<sup>16</sup> CREPC believes both products are promising tools that could actually complement each other in the broader strategy to improve efficiency of the existing grid.

While there are numerous technical issues, CREPC makes the following observations about implementing a redispatch or a conditional firm type service in the Western Interconnection. Redispatch makes the most sense in regions with independent system operators (ISOs) such as the California ISO or the Alberta Electric System Operator (AESO), or areas covered by very large balancing authorities with generation resources in place on both sides of transmission constraints. In ISO systems, a centralized entity is capable of identifying and ordering changes in dispatch patterns across a broad system of generators. Aside from the CAISO and AESO, the rest of the Western Interconnection operates on a contract-based system. Small balancing authorities outside of ISO systems tend to have fewer generation resources at their disposal and less system-wide coordination than an ISO system. Evaluating and executing redispatch options may be more problematic in the decentralized institutional structure of the Western Interconnection. Moreover, coordination across the seams of an ISO system with contract-based balancing authorities may become complex given the different institutional structures and methods of executing transactions.

In contrast to redispatch, analysis of a potential conditional firm service would focus on seasonal patterns of power flows on specific lines, but would not have to account for generation availability or generation costs on constrained paths. This analysis would quantify the probability of curtailment for different periods of the year and provide the customer firm service for a portion of the year. Redispatch and

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<sup>16</sup> NOPR, at 305.

conditional firm would both require some forecasting to assess the availability of transmission capacity during periods in the year, while acknowledging the risks associated with forecast errors for such transmission service. Conditional firm may be more effective than redispatch in remote areas where existing transmission facilities are used for only a portion of the year.

Conditional firm and related products have emerged as an important topic in the West.<sup>17</sup> CREPC encourages the Commission be flexible and foster innovation in developing such products. Given the diversity of proposals, however, a clear definition of all attributes of conditional firm service is needed before adding a required service to the OATT.

In summary, CREPC encourages the Commission to advance reforms to enhance the availability of long-term firm point to point service. Such reforms are critically important to promoting a more efficient use of the existing grid, and provide the best opportunity to stimulate new clean and diversified generation resources in the West. Redispatch and conditional firm service are promising tools but important technical questions need to be considered and evaluated before these services are required for long-term service, particularly in the decentralized structure of much of the Western Interconnection. We encourage technical workshops to address these issues, and encourage a flexible and adaptive approach in promoting innovative solutions.

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<sup>17</sup> The Rocky Mountain Area Transmission Study (RMATS) identified conditional firm and priority non-firm service as potential new tariff products to better utilize the grid. Rocky Mountain Area Transmission Study, Phase I, September 2004, at 5-14. The Bonneville Power Administration (BPA) proposed a conditional firm and redispatch service. BPA's proposals were the subject of a Commission technical workshop in Portland in March 2005. Federal Energy Regulatory Commission, Technical Workshop on Additional Wholesale Electric Transmission Services Under Order No. 888 Open Access Pro Forma Tariff, Docket Nos. RM05-7-000 and AD04-13-000, Portland, OR, March 16-17, 2005. The Western Area Power Administration (Western) offers a Priority Non-Firm product on a long term basis, which has a curtailment priority below "firm" service but higher than all other "non-firm" service

## **2. Hourly Firm Service**

CREPC supports the Commission’s initiative to create hourly point-to-point firm service into the *pro forma* OATT. CREPC also supports the Commission’s proposal to allow transmission customers to batch requests and schedules for hourly firm service provided within the same day.

However, the NOPR proposes use of the “IES Method” and applying different pricing for hourly firm service based on whether the service is taken in peak or off-peak hours. The price of peak hourly firm service would be based on the number of peak hours in a year. The number of peak and off-peak hours in WECC is different than proposed in the NOPR. The Commission should allow for this difference in peak hours to determine peak pricing.

Further, CREPC recommends that scheduling for hourly firm service conform to the existing scheduling practice in each region, and that it has the same priority as conditional firm service.

## **3. Rollover Rights**

No comments.

## **4. Modification of Receipt or Delivery Points**

No comments

## **5. Acquisition of Transmission Service**

### **Processing of Service Requests.**

In its Notice of Inquiry, the Commission sought comments on four issues surrounding the processing of transmission service requests: 1) timely processing; 2) remedies for missed deadlines for system impact and facilities studies; 3) queue blocking; and 4) clustering requests for studies. In this NOPR, the Commission establishes requirements and provides guidance to further address the need for transparency and accountability to insure that the processing of these requests is fair, reasonable, and non-discriminatory. CREPC believes that the processing of transmission service requests is critical to assuring available transmission to meet the needs of electricity customers reliably and cost-effectively from new and existing generating resources in the Western Interconnection.

**Timely Processing**

In response to concerns regarding the timely processing of transmission service requests, the Commission focuses on those requests requiring studies. The Commission proposes requiring quarterly postings of performance metrics on each transmission provider's OASIS that track the progress of system impact studies and facilities studies. The quarterly postings would break down requests into short-term and long-term, affiliate and non-affiliate, and RTO categories. Although CREPC applauds the steps the Commission is taking to make the study process more transparent and to create an auditable trail for evaluating study performance, CREPC suggests that the Commission require the quarterly posting of the disposition of **all** transmission service requests, including those not requiring studies. In this way, the entire evaluation and decision-making process undertaken by transmission providers to determine which requests can be served with ATC and which require further study will be more transparent to market

participants. More comprehensive reporting will provide sufficient data to allow analyses of congestion and queue management and of factors indicating the need for additional transmission capacity.

Some Western states are encouraging the development of renewable resources through the establishment of Renewable Portfolio Standards or other similar targets. In Western states without these more formal requirements, utilities are issuing RFPs for renewable resources as a part of the development of Integrated Resource Plans required by the states in order to diversify resource portfolios and risks. Thus, CREPC proposes to include a separate category for renewable resources in transmission service requests and for subsequent studies.

**Remedies for Missed Deadlines**

The Commission proposes to impose operational penalties and the posting on OASIS of additional performance metrics for those transmission providers that process more than 20% of studies for non-affiliated transmission customers outside of the 60-day due diligence deadlines for two consecutive quarters. For each of the following two quarters, a transmission provider would pay a \$500 per day penalty for each day beyond 60 days the study takes to complete or the request remains in the queue. This penalty would continue until the transmission provider completes at least 90% of studies for non-affiliates within the due diligence deadlines. The Commission also notes the possibility of other remedial action on a case-by-case basis. Finally, the Commission proposes that RTOs will not be subject to this penalty regime because of their independence.

The Commission proposes that transmission providers pay non-offending, unaffiliated transmission customers when the transmission provider or its affiliate incurs

operational penalties (NOPR Part V.C.4.b.). CREPC seeks clarification of the definition of “non-offending transmission customers.” CREPC also seeks clarification of how the Commission plans to determine which unaffiliated transmission customers in the study process or in the queue beyond the set deadlines will receive operational penalty payments – all transmission customers in the study process or in the queue, or only those exceeding the 60-day deadline? CREPC also seeks clarification of the amount of the monetary operational penalties, that is, whether the \$500 per day is a flat rate that would be pro-rated among eligible non-offending, unaffiliated transmission customers, or whether the \$500 is a rate paid to each eligible transmission customer. CREPC believes that the former penalty -- \$500 total per day – sends a sufficient signal, along with the proposed additional posting requirements, to the transmission provider without being overly punitive. CREPC also notes that, while it may be reasonable for an investor-owned utility to pay penalties without being allowed to recover the penalties in rates, this approach will be problematic for utilities that do not have shareholders.

CREPC proposes that transmission projects crossing those seams not be subject to penalties because in the Western Interconnection seams exist between the California ISO and interconnected transmission providers to the north, east, and south, as well as between U.S. and non-jurisdictional, non-U.S. transmission owners, and extensive transactions across those seams.. An exemption from penalties will create a level playing field for those transmission providers working with the California ISO and foreign transmission owners to resolve transmission service requests.

***Queue Blocking and Queue Processing Business Practices***

The Commission also seeks comments on the disposition of multiple “self-competing” transmission service requests and on whether a processing fee would provide a disincentive for this behavior, including fee structure, standards for identifying requests subject to a fee, the level of the fee, and circumstances for refunding the fee. Self-competing requests have the same point of receipt, point of delivery, source, sink, time frame, and firmness. Some requests are for the same service at two or more locations for the same source.

Recognizing that there is a fine line between discouraging identical requests when only a single request will be confirmed and encouraging flexibility in the development of resource projects, CREPC nevertheless agrees that blocking behavior in the queue should be discouraged so that legitimate requests lower in the queue are not disadvantaged.

Although CREPC has no specific recommendation on the appropriate level of a processing fee for multiple self-competing requests, CREPC agrees that a reasonable fee is appropriate. Refunding or crediting the processing fee would defeat the purpose of having one in the first place, although the processing fee could be refunded if the duplicative service request attached to it actually comes to fruition. CREPC also urges the Commission to adopt a simple, straightforward standard for determining self-competing requests, such as same points of receipt and delivery, same source and sink, same time frame, and same firmness, as well as the same project at multiple locations.

CREPC also supports the Commission’s determination that transmission providers’ use of the NAESB business practices referenced in Order No. 676 on queue hoarding to deny identical transmission requests and on queue flooding to invalidate identical transmission requests exceeding the total transfer capability of a path is an

appropriate prerogative for transmission providers to use to manage their queues, as long as these decisions are documented as the Commission proposes. Order No. 676 also adopted request queue processing business practices addressing standards for time limits on communications between transmission providers and transmission customers and for negotiation priority rules. While CREPC believes that the communications time limits are especially important for efficient short-term markets, CREPC is not recommending that any additional business practices be considered at this time. Instead, CREPC strongly urges the Commission to periodically review or audit how transmission providers are implementing these queue processing business practices to determine the degree of compliance.

**Clustering Requests for Studies**

CREPC proposes that the clustering of transmission service requests for studies should be **required**, not optional. CREPC believes that this requirement will result in more efficient and cost-effective execution of studies. However, CREPC supports flexibility in the way requests are clustered for study purposes, with the caveat that transmission providers post time frames or other criteria used for clustering, as well as clustered request studies in progress, on their OASIS sites. For example, requests could be clustered by time frame, path, length of service requested, or firmness of service. Transmission providers should have the discretion to develop the criteria for clustering so that transmission customers do not have the opportunity to “cherry pick” study clusters. CREPC believes that clustering requests helps alleviate some of the cost and timeliness problems small renewable generators experience when lumped into the queue with large

projects. Clustering requests for studies should not relieve transmission providers from any other requirements the Commission adopts for queue management.

**Reservation Priority**

The Commission focuses its discussion of reservation priority on short-term service requests and proposes to eliminate the first-come, first-served approach and replace it with a window of time during which all requests will be deemed submitted simultaneously. Although CREPC finds the window of time approach preferable, CREPC supports the adoption of a broader window of time for both long-term and short-term requests. A more appropriate window for long-term requests would be either a day or a week. For short-term requests, all requests within a 30-minute period should be deemed submitted simultaneously and grouped together for purposes of allocating ATC. Coupled with the discretionary use by transmission providers of the NAESB business practices on queue blocking and queue hoarding, this grouping of requests should help minimize the gaming of reservation priorities. The proposed 5-minute window is too short because it would put transmission providers in a perpetual state of determining reservation priorities every 5 minutes, which would prove to be extremely burdensome, if not inefficient. CREPC supports the Commission's proposal to use duration as a tie-breaker for all requests submitted in a 30-minute window. CREPC proposes that price be used as a secondary tie-breaker for requests of the same duration in cases where the transmission provider discounts the service.

CREPC does not support the Commission's proposal to use pre-confirmation to trump other factors in determining priority. CREPC is concerned that pre-confirmation might leave transmission customers without electricity when an entire request cannot be

filled. For example, if a 100 MW generator can only pre-confirm 10 MW of transmission service, then the generator cannot operate safely, efficiently, and economically unless it can obtain sufficient transmission service by other means to bring the unit up to an acceptable operating level. Further, CREPC is concerned that allowing pre-confirmation to trump duration in priority may result in more short-term requesters seeking pre-confirmation, thereby disadvantaging transmission customers willing to seek reservations for a longer term of service. For example, under the Commission's proposal, a one-hour pre-confirmed service request will always trump an un-pre-confirmed service request for six months.

**E. Enforcement**

No comments