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January 10, 2003

FOR ELECTRONIC FILING

Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Notice of Proposed Rulemaking on
Standard Market Design
Docket No. RM01-12-000

Dear Ms. Salas:

The City of Seattle submits an electronic filing of its Comments of the City of Seattle Opposing the Proposed Rules, Recommending that they be Withdrawn, and Recommending Alternative Actions in the above docket. Receipt may be confirmed by email at rebecca.earnest@seattle.gov

Very truly yours,

Thomas A. Carr
Seattle City Attorney

By: *William H. Patton*
WILLIAM H. PATTON
Director, Utilities Section

Enclosures

cc: Service List

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design	Docket No. RM01-12-000

COMMENTS OF THE
CITY OF SEATTLE
OPPOSING THE PROPOSED RULES, RECOMMENDING THAT THEY BE WITHDRAWN, AND RECOMMENDING ALTERNATIVE ACTIONS

On July 31, 2002, the Federal Energy Regulatory Commission ("Commission") released a Notice of Proposed Rulemaking ("NOPR"), Docket No. RM01-12. *Notice of Proposed Rulemaking. Remedying Undue Discrimination Through Open Access Transmission Service and Standard Market Design ("NOPR" or "Rule"). 67 Fed. Reg. 55452 (2002).* The NOPR proposed to require all public utilities with open access transmission tariffs to modify these tariffs to implement a new standardized wholesale market design. On October 2, 2002, the Commission issued a Notice of Conferences and Revisions to Public Comment Schedule, clarifying a comment deadline of November 15 for some issues and a January 10, 2003 deadline for comments on other topics, including issues specific to the western United States.

The City of Seattle ("Seattle") filed comments by November 15, 2002 on issues not generally specific to the western interconnection. At that time and again in this filing, Seattle urges the Commission to withdraw the draft NOPR for procedural, legal, and substantive policy reasons. Seattle respectfully submits these additional comments on western interconnection issues in accordance with the Commission's comment schedule in this docket. These comments address 1) legal issues, 2) market design in the Western Interconnection, and the application of resource adequacy standards in the West, 3) transmission planning and pricing, and 4) congestion revenue rights and transition issues.

All correspondence, communications, and pleadings in this proceeding should be sent to each of the following:

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EXECUTIVE SUMMARY

Seattle respectfully reiterates its request that the Commission withdraw the draft NOPR for procedural, legal, and substantive policy reasons.

General Comments:

The NOPR fails to provide evidence for its claim that "undue discrimination" is an inherent consequence of vertical integration. If the Commission nevertheless continues to assert that this is the case, it should be required to test the hypothesis, by region, in separate evidentiary hearings.

As matter of law, the NOPR is procedurally flawed, and must be withdrawn, for technical reasons associated with due process for federal rulemaking. The Commission has conceded that the draft tariff is inaccurate and inconsistent with the preamble in many areas. Vagueness and inaccuracy do not provide adequate notice for the due process required for federal rulemaking. If the NOPR is not withdrawn, a revised preamble and regulatory text must be issued prior to any final rule.

In particular, the Commission must clarify its intentions in a number of key areas, including "reciprocity" requirements applied to publicly owned utilities and federal power marketing agencies and what rules would apply to parties unwilling or unable to comply with key elements. The Commission must explain how it expects non-jurisdictional entities (such as the Corps of Engineers and Bureau of Reclamation for hydro facilities or the federal power administrations and publicly owned utilities) to participate in standard market design.

Pacific Northwest Issues:

The Western Interconnection is different from the Eastern Interconnection in physical, economic, and institutional terms. Resources are predominantly hydroelectric, peaking in the spring, while loads peak in the winter rather than the summer, and the Columbia River and other river systems do not store water sufficient to meet loads throughout the year. The Pacific Northwest is unusual in being an energy-limited rather than a capacity-limited system. In addition the institutional framework of the Pacific Northwest is defined and controlled by federal legislation and treaties associated with the Bonneville Power Administration. Many key assumptions in the Commission's preamble regarding wholesale and retail market structure therefore do not apply to the Pacific Northwest.

If a rule is imposed upon the Pacific Northwest, despite these unique characteristics, then minimally, transmission contract rights must be preserved in order that utilities with obligations to serve retail load are not harmed. In addition, the market design must not interfere with or prevent Seattle from operating a nested control area. Further, the Commission should rely on regions to design their own business and operating practices, planning criteria, market monitoring structures, congestion management processes and reliability criteria.

The Commission has left unresolved other key legal problems, including liability, antitrust issues, and the requirements of other federal laws affecting operations of key market participants.

If the Commission nevertheless proceeds with rulemaking, a large number of issues must be resolved far in advance of interim tariff filings on July 31, 2003. To properly address the issues in the Pacific Northwest and Western Interconnection, the Commission must make changes in the preamble and regulatory text on resource adequacy, must-offer requirements, bid caps, market monitoring, dynamic scheduling, penalties, seams, locational marginal pricing, and transmission contract rights and terms. Each region should be permitted to draft its own tariffs. Many of these changes cannot practically be addressed under deadlines currently proposed by the Commission.

BACKGROUND

Seattle owns and operates its own electric utility, Seattle City Light, serving all of Seattle and all or portions of adjacent cities and unincorporated communities of King County, Washington. The utility serves over 350,000 customers and, by that measure, is the seventh largest publicly owned utility in the United States. Seattle serves most of its retail load with hydroelectricity from Commission-licensed projects on the Skagit and Pend Oreille (Boundary Project) rivers. In addition to its own resources, Seattle purchases power under long-term agreements from numerous Northwest generating projects. The utility is also a large preference power customer of the Bonneville Power Administration ("BPA").

Seattle owns transmission lines that supply power directly from the Skagit Project, but is otherwise transmission dependent. Seattle relies heavily on transmission services provided by BPA, both to deliver power from the Boundary and other projects and to buy and sell electricity in regional power markets. Seattle also relies on interconnections with Puget Sound Energy ("PSE") to provide transmission for Seattle generating projects located within PSE's service territory.

Physical Characteristics of Northwest Hydro Resources

The Pacific Northwest electric grid has a number of unusual features. Resources, predominantly hydroelectricity, peak concurrent with spring snowmelt in British Columbia and Northwest states. Loads peak in the winter rather than the summer. The Northwest river system does not permit sufficient water to be stored to match loads to resources. As a consequence, both Seattle and the region as a whole expect to market surplus electricity in the spring and summer, predominantly to the summer-peaking southwest. Conversely, Seattle and the region as a whole expect to import primarily fossil-fueled power from the Southwest in the winter, particularly during years of low precipitation.

The majority of Northwest hydroelectric resources are located on the Columbia and Snake River systems. Federal generating projects are owned and operated by the US

Army Corps of Engineers and US Interior Department Bureau of Reclamation; BPA is responsible for marketing output from these facilities and owns the bulk of the region's high voltage transmission. The major hydroelectric storage facilities are located in the province of British Columbia, and are owned and operated by a crown corporation, BC Hydro. This entire system is operated as an integrated whole, rather than as competing individual generators, under terms and conditions embodied in both international treaties and the Pacific Northwest Cooperation Agreement.[1] These treaties and agreements are designed both to maximize the integrated value of the hydro system and meet concurrent requirements associated with irrigation, navigation, flood control, recreation, and fish and wildlife protection.

Many public and private utilities operate both non-federal hydro projects, fossil-fueled generation (predominantly coal in Montana and Wyoming), and, increasingly, gas-fueled generation and wind capacity. Hydropower accounts for more than 50 percent of the region's average annual generation, with substantial year-to-year fluctuations.

Institutional Characteristics of the Northwest Grid

The institutional framework for the Pacific Northwest electric grid is heavily defined by federal legislation and Treaties associated with BPA and the region's public and private electric utilities. Under the Regional Power Act (16 U.S.C. 839), Bonneville is statutorily responsible for meeting the net electric demands of all existing public utilities in the region as well as residential and small farm loads of investor-owned utilities. It is therefore a wholesale power provider with firm retail service obligations. This is at least unusual and possibly unique in the United States.[2] With the exception of service to certain statutorily defined retail customers (the direct service industries), BPA does not serve retail load directly.

BPA is also the dominant regional transmission provider, owning approximately 75 percent of the regional high-voltage electric grid. Transmission ownership may be

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[1] US Army Corps of Engineers, US Department of Energy/Bonneville Power Administration, US Bureau of Reclamation, *A Guide to the Pacific Northwest Coordination Agreement,* 1993.

[2] These were factors that led Congress to exempt Bonneville from the transmission provisions of the 1992 National Energy Policy Act, though subsequent administrations have elected to comply with the Energy Policy Act.

split among parties; Seattle, for example, owns a capacity share of the BPA-operated Third AC Intertie to California. Reciprocal use of transmission has been practiced for many decades, driven in part by joint ownership of generating resources, transmission facilities, and the distance from resources to loads. As a federal agency, BPA is empowered to build all new transmission required to meet regional requirements loads, including for public preference customers located entirely within an existing investor-owned "service territory."

The Regional Power Act directs Bonneville to pursue "least cost" resource acquisition under the aegis of the Northwest Power Planning Council, a regional compact created by Congress and the legislatures of Idaho, Montana, Oregon, and Washington. The Regional Power Act requires the Power Council to prepare regular regional plans that place priority emphasis on energy efficiency improvements and renewable energy resources. Any large new resource acquisitions by Bonneville must be approved by the Regional Power Council for consistency with the plan.

Many aspects of power system operation also involve Treaties with Canada and operating agreements, such as the PNCA, described above.

Retail market design is determined by the region's State Legislatures, regulatory agencies, and local governments. With the exception of Montana, virtually all retail loads in the region are provided at traditional cost-of-service rates by a mixture of both locally regulated non-jurisdictional publicly owned utilities and investor-owned utilities. The state of Washington does not have geographically defined franchise service territories.

Economic Characteristics of Northwest Hydro

Federal power resources in the Northwest (including output of WNP-2, a boiling water reactor on the Hanford Reservation) have had an average delivered cost of $18-$24 per MWh over the last decade, inclusive of all capital, fuel, and other operating costs. Resources owned by the region's public and private utilities are also generally low in cost. As a consequence, until the 2000-2001 energy crisis, the Northwest has had retail rates approximately half the national average.

Natural climatic fluctuations and the absence of significant year-to-year storage mean that the output of the Northwest system varies substantially. In good water years, the region generates about 4000 aMW of surplus "non-firm" electricity for sale in spring and summer. During good water years, this surplus can drive spring and early summer Western market clearing prices below $10/MWh.

Conversely, in a poor water year, the Northwest system must rely on imports from the Desert Southwest and California.

The Northwest is particularly unusual in being an "energy-limited," rather than "capacity-limited" system. In general, the region's generating units can meet all foreseeable peak demand in winter and will be able to do so for many years to come.[3] The planning focus is instead on meeting aggregate (total kilowatt-hour) demand over the planning horizon, particularly in adverse water conditions. The Regional Power Council does regular assessments of supply availability and reliability. Analytically, it should be possible for the Regional Council to develop a probabilistic approach to loads, rainfall, and forced outage rates that would provide the same level of bulk system reliability as a reserve margin target in a capacity limited system.

In a low-cost, energy-limited system, utilities and regional planners justifiably emphasize investments in energy efficiency, with the goal of reducing aggregate consumption rather than peak demand. Kilowatt-hours saved during summer evenings – nearly valueless from the perspective of some planners from thermal systems – can be just as valuable as kilowatt-hours saved on peak. Off-peak savings often permit water to be stored (within diurnal and seasonal limits) to meet peak demands.

Northwest generation is also operated in a somewhat counter-intuitive fashion. Thermal generation is generally run as a baseload resource. Hydro generation is used to follow loads and balance the system in real time. Hydro plant dispatch is optimized for energy production per cubic foot of water, which varies based on hydro conditions, and physical plant characteristics while meeting a multitude of constraints including irrigation, navigation, flood control, recreation, and fish and wildlife protection. This is

[3] There are some limits associated with meeting sustained peak demands, because reservoirs are being drawn down more quickly than they can be replenished, but this does not drive incremental supply planning.

not classic, "merit-order" dispatch, where plants with the lowest operating cost operate first. It is nevertheless economically efficient on an annual basis.

Conclusions and Implications

For those familiar with thermal systems in the Eastern Interconnection, the physical, institutional, and economic characteristics of the Pacific Northwest system may be difficult to grasp. In the Eastern Interconnection, many generators compete with each other, in merit order to minimize fuel costs in a tightly dispatched network grid. Many suppliers can compete with each other and sell at market price at individual system nodes. Non-jurisdictional utilities exist, but have a very small market share. New resources are built either in response to peak demand price spikes or regional capacity requirements. Power supplies may be tight at times of system peak, but are otherwise ample, and off-peak prices reflect marginal fuel costs. Utility investments in conservation focus on peak demand. Resources are generally built within service territory boundaries; these boundaries can be used to limit competition and create significant price differentials between adjacent regions.

In the Northwest, generation is cooperatively dispatched because of the number of physically integrated facilities that share the same fuel source and must function jointly to accomplish a range of hydro system goals. The same water that passes through Grand Coulee dam directly affects more than 21,000 MW of Columbia River system hydro generation. Therefore it is not possible to establish significant independent day-ahead schedules and unit commitments for many generating facilities.

Only a small fraction of the total resource base is sold at a market clearing price; most generation is owned by load-serving entities selling bundled retail electricity to firm loads. Non-jurisdictional parties dominate. New resource acquisition by BPA is heavily governed by a regional least-cost planning process embodied in federal law.

A standard market design tailored to issues and challenges in the eastern interconnection fits awkwardly, if at all, in either the West or the Pacific Northwest. Efficiency investments and conservation programs in the Northwest therefore generally focus on aggregate, rather than peak, demand. This is not to say that the West or

Northwest have entirely clear rules and solid regional planning process for new generation, transmission, and efficiency investments, or can clearly articulate the role the Commission should play in ensuring that wholesale electric rates remain fair, just, and reasonable. Alternatives to LMP and ITPs should be considered for the Western Interconnection.

Market characteristics in the Pacific Northwest, and perhaps in the West as a whole, create a particular challenge for market monitoring, price mitigation, locational marginal pricing, and analysis of market power. When Western energy markets are in surplus, hydro operators can, for the most part, make intelligent decisions on opportunity cost. It is the cost of buying energy in the wholesale market later in the year. Again, theoretically, that price should reflect marginal fuel costs in the Southwest – perhaps $20-$40 per MWh. The major challenge is whether it is possible to devise a locational pricing system that works in tight supply situations, without extremely complicated systems for price mitigation and market monitoring. A secondary challenge is whether the implementation costs, and schedule, outweigh any foreseeable economic benefits.

The Commission identifies a set of tools for addressing both locational market power and horizontal market power. For load or generation pockets, the Commission proposes a "number of sellers" test to evaluate market power. Others have suggested a "pivotal suppliers" test. Would an outage by a key supplier, unexpected or otherwise, trigger prolonged local prices higher than marginal cost? If so, the Commission would suggest that plants in such pockets be limited to cost-plus supply bids.

Outside load pockets, the Commission proposes to rely on a "safety-net" bid cap of $1,000/MWh to prevent abuse of market power. Some, including Commission staff, argue that the safety net bid cap should be lifted entirely if a region has implemented sufficient "demand-side" bidding.

For the Northwest, and perhaps many parts of the Western Interconnection, the pockets may be larger than the plants. This arises out of the physical and economic characteristics of the Western Interconnection. The largest and cheapest generating plants are generally located far from loads; but rural loads are in generation pockets with dominant single sellers. Urban areas – including nearly all of Puget Sound – are generally load pockets, with very limited local generation. State regulation of the price of bundled retail electricity prevents these plants in either load or generation pockets from using locational advantages to raise rates. If locational marginal pricing is nevertheless implemented, a very large fraction of Western generation must remain committed to load service under bilateral contracts and any remaining supply margin may need to operate under cost-plus adders that could be plant specific. This issue is further complicated in the Pacific Northwest by the need for cost-plus adders to be driven by opportunity cost – which has no theoretical upward limit or verifiable marginal cost in a supply emergency.

It is not at all clear that a safety net bid cap of $1,000/MWh leads to fair, just, and reasonable rates outside load pockets. Load and generation pockets were not responsible for runaway prices in the Western Interconnection in 2000-2001. A safety net bid cap of $1,000/MWh would have done very little to ameliorate the economic damage done throughout the West from persistent on- and off-peak wholesale electricity prices of roughly $350/MWh.

Demand-side investments are important for many reasons, but may not be as useful in an energy-limited system or in a system that serves primarily residential and commercial load which is increasingly the nature of loads in a service-oriented economy. It is certainly true that demand-side savings helped cushion the 2000-2001 energy crisis, but many of these "savings" involved not peak-hour cutbacks but monthly or seasonal shutdowns of industrial plant.

The Commission must approach these issues with caution. A locational marginal pricing system in the Northwest may be very difficult and expensive to implement, and potentially easy to manipulate. It may require plant-specific price controls on many generators. These price controls would generally be unnecessary because plants in load and generation pockets are not setting locational marginal clearing prices for energy and transmission services; they are predominantly delivering state-regulated bundled electricity to firm retail customers. They are prevented from setting locational marginal price, or abusing potential market power, by the characteristics of state regulation.

In the Western Interconnection, some suppliers (e.g., California merchant plant operators and gas pipeline operators) were clearly able to ensure that Western electricity market clearing prices were persistently higher than marginal cost. Neither the "number of suppliers" test or a "pivotal suppliers" test, nor the safety net bid cap would have addressed the 2000-2001 western system crisis. The Commission should not imply that the remedies proposed in the NOPR will prevent another "California crisis."

KEY ISSUES

I. Legal Issues

A. Reciprocity

The NOPR indicates that non-jurisdictional utilities, including federal power marketing agencies, would comply with specific provisions through the Commission's rules on "reciprocity." The Notice indicates that reciprocity requirements are met if non-jurisdictional entities provide open access transmission services under Order 888. Many commenters – and Commission staff themselves – have suggested that reciprocity provisions in the final rule will differ substantially from the provisions of the draft tariff. Commission members, including the Chairman, have indicated that the final rule will have a combination of "penalties" and "incentives" to ensure participation by non-jurisdictional entities.

Seattle and most non-jurisdictional entities would clearly prefer the language of the draft regulatory text (Appendix A, Part 35.35(d)) and tariff to any provision that provided penalties for failing to achieve full compliance with SMD. Without specific knowledge of the penalties under consideration for adoption in a final rule, Seattle cannot effectively respond to the draft tariff. Failure to provide notice violates due process requirements associated with federal rulemaking.

In addition, Seattle is particularly concerned about reciprocity provisions that might be applied to BPA, either by a policy decision by the Administration or stronger rules imposed by the Commission.

Seattle's views on this issue have been raised in November 15 filings with the Commission.[4] To reiterate briefly, the Commission cannot regulate entities that it is expressly prohibited from regulating under the plain language of the Federal Power Act. At the same time, Seattle fully understands that many provisions of the draft tariff (e.g., on resource adequacy) would be impossible to implement for only a fraction of Northwest load-serving and transmitting utilities. At a recent Boise workshop, Commission staff indicated agreement with the notion that the reciprocity provisions of the draft tariff were unworkable for the West.

In general, it provides Seattle no comfort to have to respond to a sweeping redesign of Western power markets that is either illegal (under the plain reading of law, if the Commission attempts to force full SMD compliance on non-jurisdictional entities) or unworkable (if the Commission does not). The reciprocity issue deserves greater immediate attention from the Commission, particularly for the Western Interconnection, where more than the half of all transmission is owned by non-jurisdictional entities. If the Commission is considering other options beyond those considered in the draft NOPR, notice of alternative approaches must be provided to meet standards of due process required for federal rulemaking.

B. Liability

The draft NOPR has no explicit provisions with regard to liability protection for load-serving entities that transfer all transmission assets necessary to serve bundled retail load to an independent transmission provider (ITP) or regional transmission organization (RTO). Nor does it provide liability protection for generating plant dispatch and redispatch decisions made by an ITP under a Participating Generator Agreement. Any SMD tariff must include provisions that limit transmission and generation owner liability for ITP actions that may expose load-serving entities to potential tort liability.

Most states provide explicit liability protection for utilities associated with either ordinary negligence or gross negligence and misconduct. In Washington, utilities have limited liability for ordinary negligence and are responsible only for direct damages in

[4] See comments of the City of Seattle and comments of the Large Public Power Council, November 15,

the case of gross negligence and misconduct. An ITP is not a utility in the state of Washington. Its actions are exclusively jurisdictional to the Commission. Utilities that transfer any reliability duties to an ITP inevitably expose the underlying utility to claims that neither the utility nor state statutes can protect against. Additionally, ITPs are likely to own little or no assets, leaving underlying utilities vulnerable to claims for which there is no state liability protection.

The Commission should, and perhaps must, provide liability protections for utilities that either voluntarily or by final rule transfer operational control of transmission or generating assets to an ITP. Under the terms of the draft tariff, the ITP has additional responsibility in assessing load forecasts, supply portfolios, efficiency programs, and demand-side bidding programs of load-serving entities. Load-serving entities must also be protected from liability from decisions made by the ITP to either accept or reject these submissions.

C. Antitrust

The NOPR is silent on the question of antitrust risk inherent in regionally organized energy and transmission markets. The operation of Columbia River system hydroelectric generation is currently governed by intricate laws that require cooperation to accomplish multiple energy, fish and wildlife, flood control, navigation, and irrigation objectives. These goals are pursued in a power system that is overwhelmingly cost-based. While federal regulations generally protect parties from antitrust risk, the SMD proposal, by emphasizing market-based principles, calls into question whether traditional cooperative agreements in the Pacific Northwest, such as the PNCA, Vernita Bar Agreement, or Mid-Columbia Hourly Coordination Agreement, pose antitrust risks.

II. Market Design in the Western Interconnection

Market design in the Western Interconnection must proceed from an acknowledgment by the Commission of the physical, economic, and institutional differences that characterize the western system. The Commission should not impose a

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Standard Market Design on the Western Interconnection. The West as a whole is characterized by a sparse network with numerous radial interconnections and load pockets, rather than a densely networked transmission system. Major traditional Western generating resources – hydroelectric and coal, with some nuclear plants – are often located hundreds or even thousands of miles away from loads. Almost paradoxically, new resources (predominantly gas-fueled) are much likelier to be sited locally rather than remotely.[5] New resource development is unlikely to lead to a more networked Western grid.

Most loads in the West are served by vertically integrated utilities selling at regulated prices to retail customers. Between 1985 and1995, most Western utility resource additions involved long-term contracts with independent power generators. After that time, utilities relied for incremental needs on a relatively robust wholesale power market, based initially on the bilateral, Commission-regulated Western Systems Power Pool (WSPP) and later dominated (at least volumetrically) by the California Power Exchange (PX).

By and large, the role of purely "merchant" generators (independent producers without long-term contracts) has been limited. The vast majority of merchant generation in the West involves privatized utility generation in the state of California. After the creation of the California Power Exchange, most Western power market planners – including the California Energy Commission and Northwest Power Planning Council – anticipated new merchant capacity additions when prices in the Western Interconnection (either in the WSPP bilateral market or PX) reached $28-$35 per MWh.

With the glaring exception of the 2000-2001 Western power crisis, Seattle generally agrees with the conclusion that the structure of bilateral markets in the West is workably competitive. A workably competitive structure may not, however, produce prices that are "fair, just, and reasonable," as required by the Commission's enabling legislation. In general, Seattle suggests that the Commission's role lies primarily in building upon the existing bilateral western power market to achieve greater

[5] Marginal gas pipeline capacity is generally much cheaper than marginal high voltage transmission capacity. Gas-fired generation also poses fewer air and water related siting challenges. Wind can also be a cost-effective marginal resource, but must usually be sited more remotely.

transparency, comparability, security of supply, and protection against market manipulation.

Seattle places priority emphasis on firm service to retail loads. To that end, generation management, the preservation of existing transmission contract rights, maintenance of existing control area functions, and dynamic scheduling all ensure that the needs of Seattle's retail customers will be met with high reliability and predictable costs. Each of these issues is discussed below. In addition, Seattle offers recommendations on enhancements to the existing bilateral western power market that should achieve many of the Commission's wholesale power market goals.

The Commission should work with the regions to achieve the broadest objectives of this market design effort rather than imposing a rigid structure. In the Northwest, the RTO West effort is addressing the broad objectives of Order 2000 and the SMD NOPR within the constraints of the regional transmission system, planning and operating criteria, and other necessary regional considerations. The Commission should expect to see a proposal for the Northwest region that contains significant variations from the SMD tariff. But rather than evaluating it for strict compliance with the SMD tariff, the Commission must apply broader principles to determine whether it achieves the goals required under the Federal Power Act.

A. Resource Adequacy

The Commission requested specific comments by January 10, 2003 on the resource adequacy standard in the NOPR. The Commission is to be commended for recognizing that prices in wholesale power markets are not likely to lead to construction of sufficient generating capacity to avoid unacceptable volatility and price spikes. To ensure adequate infrastructure to meet loads, the Commission would require that all load-serving entities forecast future loads, and that regions either maintain a minimum 12 percent reserve margin, or establish their own level of resource adequacy. Load forecasts would be evaluated for accuracy by the Independent Transmission Provider. The ITP would also be responsible for assessing whether the utility's total portfolio, which might consist of owned resources, demand-side measures, and firm power supply and transmission contracts, met the Commission's minimum reserve margin standard or a higher level that individual regions might adopt.[6] A region will be permitted to set the level of resource adequacy, set its own planning horizon, and select from a combination of supply and demand response resources for meeting its needs.

Differences between load-serving entities and the ITP would presumably be resolved by the Commission. Failure to maintain adequate reserves would lead to penalties imposed on load-serving entities. The NOPR indicates that the resource adequacy approach must be in place by July 31, 2003.

The Commission's proposal poses a number of difficult problems, both nationwide and in the Western Interconnection. The first problem is one of jurisdiction. The second involves the application of a reserve margin standard to the Pacific Northwest.

1. Jurisdiction

Nowhere in the Federal Power Act is the Commission granted jurisdiction for generation additions, utility load forecasting, or design of demand-side measures. Under the SMD proposal, however, new resource additions, load forecasting, and the design of demand-side measures appear to be shifted from states and local policymakers to the Commission. Both the statutory and legal records expressly find that the Commission does not have authority over these elements of retail electric service.

This issue is particularly daunting in the Western Interconnection, with a very large fraction of generation, transmission, and load served by non-jurisdictional entities, including federal power marketing agencies and publicly owned utilities. It makes little sense to have jurisdictional entities required to meet planning reserve targets with non-jurisdictional entities exempt. On the other hand, non-jurisdictional entities would vigorously resist any effort to "federalize" their load forecasting, demand-side management, and resource planning decisions.

State regulators are similarly unwilling to cede jurisdiction over these fundamental elements of retail electric service. States (and local government) are

[6] The NOPR concentrates on marginal supply and transmission resources that meet the reserve margin target, but a complete assessment must consider the reliability characteristics of a utility's entire demand and supply portfolio.

responsible for the land use planning decisions that are associated with new electric power generation. These decisions incorporate environmental issues, public health and safety, and utility service reliability – all traditional responsibilities of state government. The proposal that ITPs develop Regional State Advisory Committees (RSACs) to address state concerns does not solve the underlying jurisdictional issue. Legal jurisdiction either falls in state and local government hands or it falls in federal hands. It is difficult enough that transmission jurisdiction (the Commission for wholesale interstate; states for retail and intrastate) is divided under current law. It would be a serious mistake to extend the Commission's jurisdiction to generation development, load forecasting, and demand-side investments.

As described in Seattle's November 15 comments, the assertion of federal jurisdiction in these areas may have serious implications for infrastructure development. The decision of an ITP to accept a utility's new resource portfolio is, in effect, a federal decision with immediate potential retail rate implications. Under the filed rate doctrine, ITP portfolio and forecast findings potentially trump, and will almost certainly conflict with, with the major role states play in ensuring that new resource investments be least cost, environmentally sound, reliable, and prudently incurred. The fact that ITPs might incorporate a Regional State Advisory Commission is no substitute for the exclusive jurisdiction states have had in these areas. States are unlikely to concede this loss of authority without protracted litigation, creating an untenable investment climate for new power supply and transmission investments.

2. Application of Planning Reserve Margins in the Pacific Northwest

In the Pacific Northwest, the application of a planning reserve margin requirement is particularly awkward. Many individual load-serving entities – particularly publicly owned utilities served on a "requirements" basis by Bonneville – do not individually forecast loads or contract for peak reserves. Many Northwest non-generating utilities may be unable to show that they have contractual proof of peak reserves and firm transmission surplus to forecasted load. Such requirements were nowhere contemplated in the Northwest Regional Power Act or in long-term contracts recently concluded by the Bonneville Power Administration.

The Commission should withdraw its proposal for a resource adequacy requirement. The issue is clearly important, but the current proposal is deficient for numerous reasons. There are clear conflicts with major elements of state regulation that will almost certainly trigger prompt litigation, and undermine needed infrastructure investments. In regions where the obligation to serve retail loads is very largely intact, as it is in Western Interconnection, electric utilities have every incentive under state law to meet their firm retail service obligations through portfolios that include owned resources, purchased power, and demand-side investments.

It is impossible to assess the impact on non-jurisdictional entities, particularly in the Pacific Northwest, where peak reserve margins have little influence on either regional reliability or long-term resource adequacy. If the region is nevertheless required to implement a planning reserve requirement that reflects the characteristics of regional loads and resources, the timetable for implementation is unrealistic.

B. Must-Offer and Must-Run Requirements on Hydro Generation

Toward the end of the 2000-2001 Western power crisis, the Commission imposed a market power mitigation strategy designed to increase generation availability and reduce market clearing prices. A key feature was the imposition of a "must-offer" requirement on thermal generating capacity. This requirement remains in force throughout the Western Interconnection.

At various times in late 2000 and early 2001, the Commission considered and elected not to apply the same must-offer requirement to energy-limited hydroelectricity.[7] The NOPR now proposes that hydro generators must offer to the Independent Transmission Provider "all available capacity" at hydro projects, to clear congestion, during periods of shortage or emergency, or when the market monitor finds that conditions are not competitive [see SMD NOPR at ¶¶ 327, 406-412, 422-423 and Tariff §§ 2.7, 3.7, 4.7, 5.7, 6.7].

For a variety of reasons, Seattle opposes this provision to the extent it may be included in the final tariff or in participating generator agreements. Hydroelectric resources are subject to numerous, and often conflicting, operational requirements associated with flood control, navigation, and environmental laws, including the Clean Water and Endangered Species acts. Many requirements involve treaty obligations and bilateral agreements (for example, for Seattle's Skagit Project), in addition to provisions of Commission licenses. An Independent Transmission Provider or Regional Transmission Organization has none of these obligations.

"All available capacity" should certainly not be defined by the physical potential of the turbines and reservoir. Hydro operators cannot be required to generate under conditions that violate or potentially violate license requirements. Even if Seattle were able to precisely limit "all available capacity" to levels fully compliant with existing law, the cumulative effects of such operations could have significant negative effects on its ability to follow loads, manage its resource portfolio, and comply with both the spirit and letter of its environmental commitments. Moreover, it is unlikely that an ITP, solely responsible for efficient system dispatch, would or could assume liability for operations that potentially place Seattle's license in jeopardy. An ITP unknowledgeable about plant operating characteristics could use the automatic control mechanisms embedded in the SMD LMP processor to aggressively dispatch the plant, possibly causing physical harm to the plant and its operators.

Seattle would not accept an operating regime administered by regional dispatchers that stops just short of violating laws, contracts, Treaties, and license conditions. The Commission must reconsider the implications of turning generating plant control over to a non-licensee.

The US Bureau of Reclamation has made similar arguments in its November 15 filing with the Commission. Seattle assumes that virtually all hydroelectric operators, both federal and non-federal, view the problem similarly.

For energy-limited hydroelectric plants, the decision to generate at a particular time involves an opportunity cost assessment. During the 2000-2001 energy crisis, a series of orders from the Secretary of Energy required Northwest utilities to sell

[7] Pumped storage hydro, which exists in the Western Interconnection but not in the Pacific Northwest, is not energy-limited.

electricity to California. Pursuant to exemptions under Federal regulation, Seattle refused to make such sales, given the condition of its hydro reservoirs and the expected control area deficits for the winter. That set of factors cannot be balanced in a must-offer requirement in the SMD proposal unless the same kind of exemptions are provided for utilities operating energy-limited hydro capacity, no matter how well conceived. Must-offer requirements for thermal plants, for the most part, present significantly less difficult problems.

C. Consolidation of Control Area Functions into a Single Entity

For reliability reasons, and in order to accommodate coordinated operation of hydro resources while staying within hydrological and environmental constraints, the Commission should not require consolidation of all control area functions into a single regional entity. Load-serving entities that maintain balancing capabilities will ensure greater system reliability. There is no evidence to conclude that all control area operators are able to, or will, practice undue discrimination.

Furthermore, many control areas, such as Seattle's, were not designed to manage regional transmission, and therefore have little or no ability to influence energy markets in ways articulated in the NOPR [¶45, ¶336, and Appendix C]. Seattle invested capital and planning resources to perform energy scheduling and balancing functions, to provide higher local reliability and to reduce cost. Seattle must be able to continue to provide these services for its customers. In general, the Commission should recognize the value of such nested control areas that can enhance reliability and at the same time have no deleterious effect on energy or transmission markets.

D. Dynamic Scheduling

Many control areas, including Seattle, use dynamic scheduling to ensure that their loads, interchange transactions, and resources are balanced within control tolerances established by regional reliability councils. A substantial fraction of Northwest generation involves resources (e.g., run-of-the-river hydro) with highly variable and often unpredictable output, even on a day-ahead basis. Dynamic scheduling provides a means to integrate multiple intermittent resources, non-dispatchable resources, loads and dispatchable resources to maintain constant hourly values for net interchange.

Much of the discussion in the SMD NOPR concerns hourly clearing of bids and schedules in Day-Ahead and Real-Time energy markets. Dynamic scheduling is a real-time operating procedure that is coordinated with the transmission operator on an instantaneous basis. Hourly schedules are maintained by many individual entities controlling the balance between loads and generating resources in real time. Self-supply of regulation and load-following services, as permitted by the SMD NOPR, necessarily implies that a form of dynamic scheduling is being executed between the load-serving entity and its generating resources. The SMD rule should include provisions that ensure that ITPs accommodate dynamic scheduling without assessing unwarranted uninstructed deviation penalties. The NOPR at ¶ 316 suggests that penalties for uninstructed deviations could be based on whether they affect reliability or cause increased regulation costs. Dynamic scheduling is a particularly important tool for balancing loads and resources in the Pacific Northwest, and should be permitted in any final rule.

E. Penalties

The Commission proposes that the ITP and market monitor can impose penalties when actions by market participants threaten reliability or violate market rules. Seattle does not object to imposition of penalties under well-defined situations that threaten reliability (e.g. failure to curtail schedule as described in ¶ 160) or when market rules have been violated (e.g. economic and physical withholding, failure to deliver energy as scheduled, uninstructed deviations). Reliability violations can create interconnection-wide impacts with costs that are difficult to quantify or pinpoint.

While penalty provisions may be an inevitable feature of properly functioning wholesale markets, they should be designed as a final line of defense for protecting reliability and consumer welfare. The design of penalty provisions will necessarily have regional market attributes. For reasons described above in the discussion on resource adequacy, the approach in the Pacific Northwest for violating planning margin targets may be extremely complex and perhaps unworkable. Therefore, each specific regional implementation will need greater flexibility than that proposed by the NOPR at ¶ 548. Regions must be permitted to decide whether the bases for the penalties proposed in the NOPR are relevant and develop the appropriate metrics to define the criteria and triggering mechanisms for any penalties.

F. Uninstructed Deviations

The SMD NOPR at ¶ 316 seeks comment on whether additional charges or penalties should be assessed against market participants that make uninstructed deviations in real time from their schedules. The NOPR further suggests that the increased cost of regulation or other ancillary services is the likely cause for increased ITP costs from these deviations. The Commission should be cautious when developing its criteria in this regard. Because the SMD tariff contemplates that market participants should be able to self-supply certain ancillary services, including regulation and load-following, appropriate measures must be taken by the ITP to ensure that penalties accrue to self-suppliers only when they exceed certain error tolerances when matching resources to loads. For example, existing control areas must meet a control performance standard (CPS1) that provides a measure of their compliance with regulation standards in the interconnection. Appropriate control criteria must be established that would provide an operational deadband within which the scheduling entity, especially a nested control area such as that operated by Seattle, does not incur uninstructed deviation penalties for load-following.

G. Seams in the Western Interconnection

At ¶ 219 the NOPR asks whether the entire West must have a common set of market rules to eliminate seams and prevent manipulation. The answer is no. Various regions in the Western Interconnection have different characteristics, mixes of resources, contractual obligations and legal requirements that lead to different market rules. It is quite feasible, however, to resolve seams issues without imposing a common set of market rules across the Western Interconnection. Interface rules are currently being developed by SSG-WI that will ensure that efficient energy transfers can occur between the regions.

The questions relating to cost recovery for through and out transactions are also relevant here [SMD NOPR at ¶ 179-189]. The cost shifts that would result from loss of revenues for these transactions are substantial in the west. Seasonal variations in power flow patterns are common in the Western Interconnection because most Northwest load-serving entities rely on imports during the winter. Load-serving entities in other parts of the west rely on surplus Northwest hydroelectricity in the spring and summer.

In either case, exports are comparable to load withdrawals at the edge of the regional boundary (referred to as a "seam"). The transmission system must be designed with the capability to make these transfers possible, and the cost of that additional capability should be assignable to those who benefit. Merchants that schedule through and out transfers should be allocated costs for long-term transmission services. As such, these merchants should receive CRRs to ensure either firm delivery or a congestion hedge.

For short-term service, the through and out transactions could be charged a fee similar to short-term firm PTP rates. Again, the seller should receive CRRs. The Commission should keep in mind that many existing PTP customers have purchased firm PTP rights equal to their generator ratings, which are greater than their load and often designate a delivery point at a seam. Merchant generators that have no corresponding load-service obligation should expect to pay system fixed costs even if they are selling to load outside the region.

III. Transmission Planning and Pricing

A. Coordinating Regional Transmission Planning and Expansion

The Pacific Northwest may be closer to coordinated regional transmission planning than almost any other region of the country. The Bonneville Power Administration now owns 75 percent of the region's high voltage transmission capacity. Because BPA is required by statute to serve the net requirements of all Northwest public utilities, it has been required to build through the geographic service territory of regional investor-owned utilities.[8] As a federal agency, BPA is able to site and built new transmission without potentially conflicting state and local licensing requirements.[9] BPA is also required to facilitate generator interconnections in the Northwest. As described earlier, many publicly owned and privately owned utilities also own high voltage lines. Because historical Northwest resources (hydro and, in the eastern Northwest, coal) were distant from loads, and often jointly owned, regional transmission cooperation dates back decades.

Improvements can, and should, be made in Northwest regional transmission planning. The region tends to rely almost exclusively on BPA for transmission expansion, for many obvious reasons. While BPA transmission rates recover all of BPA's transmission costs, access to financial markets requires regular Congressional budget authorization, a process that can limit BPA's ability to undertake major transmission system upgrades. Long-term transmission planning in the Northwest would be enhanced by a cooperative process that led to greater certainty that needed investments will be made in advance of dire need.

Market-based approaches to transmission expansion, including locational marginal pricing [SMD NOPR ¶¶ 191-202, and Appendix F], must not be relied upon to the exclusion of regional coordinated planning processes. A purely market driven approach to planning and expansion is vulnerable to market failures and dysfunction that may threaten the reliability and economics of power supply. There remains a significant need for a regional planning process in spite of any mechanisms that exist for private "ground up" investment in transmission. The regional planning process must take precedence over private investment decisions that may supplement the regional plans with additional options. The regional planning process must provide an objective review of all proposed projects to assess the technical merits of each and identify associated

[8] BPA has also met this requirement at lower cost by buying contractual rights to move BPA power to preference customers through intermediate providers. These rights are known as general transfer agreements, or GTAs.
[9] This does not mean that BPA is exempt from federal laws associated with transmission siting (e.g., NEPA or the Endangered Species Act), or is immune from the normal land use concerns associated with building new high voltage lines.

technical issues that must be resolved on a regional basis (for example: loop flows, path rating impacts).

In addition, there may be no private investment sponsor for some projects that would benefit the region. Private investment decisions in response to prices may not result in adequate expansions for various reasons. First, private parties may not be eligible to ask the state to exercise its eminent domain rights. Second, some needed and beneficial expansions may not create enough identifiable financial benefits to compensate private investors adequately, so those projects will not be built under a system that relies solely on private investment to expand the grid. BPA's statutory role, and comparative advantages as a federal agency, are an additional potential disadvantage for merchant transmission projects. A regional coordinated planning process must identify both the projects that would benefit the planning area and potential alternatives in a fair and unbiased manner. Additionally, a regional planning process would evaluate the benefits of alternative proposals and provide an independent assessment of which projects are the most cost effective and/or have the least environmental impact. Congestion price spreads are very unlikely to send enduring signals for private investment in new transmission. Congestion price spreads are, meanwhile, unnecessary to encourage investments by BPA in new transmission. Sound expansion of regional transmission can be done without reliance on potentially volatile market pricing.

B. Facilities Inclusion/Exclusion

At ¶ 369 the NOPR asks whether a "bright-line" voltage test (e.g. 69 kV) should be used to determine which facilities are subject to ITP control. Seattle opposes any bright-line (e.g. voltage-related) test for facilities inclusion and supports the 7 Factor Test to identify local distribution facilities that should not be subject to ITP control. Those facilities remaining are those facilities typically used for network service and regional system reliability.

As suggested by the sixth factor, consideration should also be given to points where tie-line metering exists since these will establish logical locations for day-ahead and real-time market settlements. For many municipal wholesale customers, this point clearly delineates where power flows unidirectionally for service to load. From an operational perspective, it is not uncommon for analog telemetry data within these local distribution systems to be shared with regional system operators to ensure coordinated operations, and this cooperation mitigates the need for ITP control within the local distribution system.

C. Losses

The definition of "Marginal Losses" causes significant concern about possible over-recovery of losses from transmission customers [See ¶ 267 and Tariff definitions]. While average system losses for a particular hour may be on the order of 4 percent, the marginal losses associated with discrete transactions increase geometrically as total transmission system loading increases. Consider the following example:

A power flow simulator was used to estimate power flows and losses for various generator to load transactions using a power flow simulation case for the Western Interconnection. In the simulation, average losses for the whole interconnection are 3,705 MW on a total load of 89,870 MW or 3.96 percent. The marginal losses for a Gen1 to load transaction are 9.79 percent; that is, if Gen1 injects 100 MW, an additional 9.79 MW are lost because of the increase in line loadings while holding all other generator outputs and loads constant. Recalculating the system average losses for that hour, load is still 89,870 MW, but losses increase to 3,715 MW or 3.97 percent of the total generation (93,675 MW). For a more distant generator, Gen2, its marginal loss value is 21.78 percent when loaded at full capacity. But the average system losses with an additional 100 MW input by this generator would be 3.98 percent.

The marginal loss sensitivity can be significant and the transmission operator will face the cost of producing or purchasing those incremental losses for the last increment of energy delivered. However, it is unfair to assign 100 percent of that cost to the last transaction on the system, and even worse to penalize the economic value of every MW scheduled by the marginal loss percentage. During actual operations the transmission operator must be assured either receipt of energy equivalent to system losses or recovery of the actual cost of the energy delivered to balance those losses. The Commission should permit use of an appropriate system average loss factor that can accomplish this objective.

Application of a marginal loss approach is likely to create the following problems:

1. The marginal loss recovery method in LMP would result in an overstatement of the system losses that occur due to the total energy delivered to load.
2. As part of a nodal price calculation, marginal loss effects could unnecessarily increase nodal prices thereby eroding the value of CRRs since losses are not hedged by CRRs.
3. Loss modeling assumptions would become extremely controversial because the loss values affecting all energy deliveries would be magnified by the marginal value.

Because of these problems, the Commission should recognize the use of system average loss factors will adequately address the assignment of transmission losses without the complexities inherent in the marginal loss recovery method.

D. Ex-Post Pricing Rule Should be Adopted

The NOPR asks for comments regarding whether to adopt Ex-Post or Ex-Ante pricing for settlement of Real-Time Market transactions [SMD NOPR at ¶ 315]. Seattle favors Ex-Post pricing settlement because it more accurately reflects actual energy deliveries. But the timeliness of the ex-post settlements is crucial.

VI. Congestion Revenue Rights and Transition Issues

A. Preservation of Existing Contract Rights

The SMD NOPR states that it is the Commission's intent to provide market participants with current firm transmission rights with new, equivalent transmission rights under SMD. This concept is essential so that entities such as Seattle can continue to deliver power from their resources to their loads without a material change in reliability or cost. Alarmingly, the details of the SMD NOPR do not appear to be fully consistent with this intent.

1. Ensuring Allocation of Transmission to Those Who Hold Contract Rights

Appendix F discusses the "Phase II Allocation of CRR Auction Revenue" as opposed to an unambiguous allocation of Congestion Revenue Rights. When the allocation of Congestion Revenue Rights (CRRs) is replaced with an allocation of CRR auction revenue (or Auction Revenue Rights, ARRs), there must be a guarantee that individual customers will receive the revenues from the sale of CRRs that were previously allocated to them based upon their existing rights.

Seattle has long-term, load-serving obligations. To meet these obligations, it has made major investments in generation, and significant power purchase commitments, that never could or would have been made without simultaneously obtaining transmission rights, or constructing transmission facilities, to be able to deliver these resources to Seattle's customers. These rights are essential to the economic viability of the utility's resource investments and to its continued ability to provide reliable service to its customers. Seattle's 350,000 retail customers will suffer severely if it does not receive rights under SMD that are, in fact, equivalent to its transmission rights today. This same issue exists for many other utilities, private, public and cooperative, that have invested in generation and made long-term purchase commitments to reliably serve customers, dependent upon related transmission delivery rights and investments.

More broadly, the Commission should reassess the need for a mandatory auction of rights held by customers with load-service obligations. While some customers may be interested in auctioning some portion of their CRRs, for the reasons stated above, long-term load-service obligations are fulfilled by resources that rely on economic transmission service. Loss of physical rights or congestion revenue rights may render the service uneconomical. No market design should mandate that transmission rights necessary to meet firm obligations be placed on the auction block.

Without knowing how the market will value congestion rights, who might own the rights, and how the Commission will monitor market power problems in CRR ownership, transmission customers that rely on transmission of energy from generators to loads face significant energy price delivery risks. Rather than creating a complicated process that requires customers to bid for the CRRs that they need to retain, and then hope to receive sufficient auction revenue to net the bids to zero, it would be far simpler to allow customers with pre-existing contract rights to reserve those rights in the form of a CRR allocation that is withheld from the CRR auction. The CRR auction should consist of residual CRRs and any CRRs that customers voluntarily choose to place in the auction.

2. Incompatible Choices

The Commission will be faced with the incompatible policy choices of either (a) maximizing CRR auction market liquidity by mandating CRR auctions, or (b) preserving existing contract transmission rights and permitting voluntary CRR trades or auctions. Transmission customers, including Seattle, use these rights today to ensure low cost, reliable service, and the Commission should recognize the significantly greater risks faced by consumers if existing rights are not preserved. While maximizing CRR auction market liquidity provides a theoretical basis for parties to compete for rights to transmission service, it also opens up a market for speculation that is divorced from any obligation to provide reliable electric service at a fair price. The proper degree of liquidity will be achieved when customers find that they are able to voluntarily trade CRRs, either bilaterally or through auctions, in ways that provide mutual benefits. Seattle strenuously opposes mandatory auctions of CRRs except for un-allocated or voluntarily bid CRRs.

3. Proper Basis for Allocation

Allocating transmission rights based on peak load, as suggested by some participants at the Commission's December 3, 2002 meeting, is inappropriate for existing point-to-point customers. Transmission is used to transport multiple commodities from the generating facilities to the load. These include energy, frequency responsive reserves, regulation reserves, spinning reserves, and non-spinning reserves. Further, an allocation based on peak load is particularly troublesome for Northwest utilities, such as Seattle, that have sized their transmission investments for generation system output. In a system dominated by hydro resources, it is crucial to recognize that the total amount of transmission capacity available from the sum of the generating plants may be greater than peak load. This is due to the variable, and largely uncontrollable, nature of the inflows, as well as resource diversity. Hydro-dominated systems will generally be capacity-rich. It is imperative that the final SMD either recommend allocation based on contract demand or historical use, or defer the allocation to regional transmission organizations.

B. Term of Contract Rights [SMD NOPR at ¶ 249]

Seattle believes that it is important to utilities with load-service obligations that they are able to secure multi-year CRRs, or that customers with pre-existing long-term contracts or resources be allocated CRR's annually based on existing rights and/or historical usage.

The SMD proposal speaks in terms of securing future rights of one week, one month, one year, or perhaps longer, in duration. "Perhaps longer" is not enough. In order to finance new generation and make prudent commitments for future supply, Seattle must be able to obtain long-term transmission rights that match the new resources. Seattle cannot build or make long-term contractual agreements for generation with a 30-year investment life, with only short-term delivery rights and congestion protection. The Commission should modify its SMD proposal to clearly provide that load-serving entities can designate new resources dedicated to serving their loads and can obtain new, long-term transmission rights that match the life of those resources.

Furthermore, the CRRs associated with additional transfer capability made possible by transmission expansion must be allocated exclusively to the parties paying the costs associated with the transmission expansion. From the perspective of a load-serving entity, "lumpy" transmission investments will be needed for load-growth and load-serving entities that fund construction must be assured that they have the ability to use or sell those CRRs as long as they own the facilities.

C. Congestion Revenue Surpluses and Deficits [SMD NOPR at ¶ 251]

The Commission should allow transmission owners to retain revenues from surplus CRR sales/auctions only if it holds those transmission owners responsible for full payment of congestion revenues to CRR holders when there is a deficit in collection of congestion revenues. Another approach could be the establishment of a congestion revenue pool that nets surpluses and deficits over a rolling time period.

Under the market structure described in the NOPR, hourly congestion revenues and Congestion Revenue Rights will seldom be exactly equivalent dollar amounts. Because CRR holders must be paid according to the face value of the CRRs in megawatts that they hold and the price spread that occurs at settlement, any mismatch between actual power flows and the face value of the CRRs held will create a mismatch between revenues and payments for the ITP. Both surpluses and deficits are likely to occur in the West because the facilities are periodically out of service for maintenance. In some cases transmission owners have contractually oversold the physical capacity of the system, transmission paths are derated for reliability reasons, and the loss methodology may prevent a perfect match between injections, withdrawals and the total face value of CRRs outstanding on all paths.

The SMD NOPR proposes that the transmission owner cover congestion revenue deficits out of its own pocket; however, the Commission also proposes that transmission owners receive surpluses when they occur. The question of whether the transmission owner receiving congestion revenue surpluses will discourage expansion hinges on whether the transmission owner is also paying congestion costs out of its own pocket (i.e. it was obligated by pre-existing contracts to allocate CRRs that it lacks the physical capacity to support). If there is no congestion, there are no congestion revenues (surplus or otherwise), and, no expansion is needed. If there is congestion, the owner can either build transmission facilities or pay congestion charges to the CRR holders out of its own pocket. There may be times when the transmission owner holds CRRs that are surplus that it can sell to recoup out-of-pocket costs. If it builds, it may have some expectation of recovering the embedded costs either through its transmission rates (which would be incorporated into the Access Charge), or by collecting congestion revenues or proceeds from CRR sales.

D. Real-Time Settlements for Units with Large Minimum Bid Increments

Seattle agrees with the Commission that units with minimum incremental output capabilities greater than 1 MW (or some other threshold) should not set marginal energy prices without adjustments for lower cost units displaced due to transmission security constraints that necessitate dispatch of the large unit, albeit out of merit order. The proposal states at ¶ 318 that lower cost, displaced generation should be compensated at opportunity cost.

CONCLUSION

Because there are so many unresolved issues, especially affecting the Western Interconnection and the Pacific Northwest in particular, the Commission should withdraw this proposed rule.

Respectfully submitted this 10th day of January 2003.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Comments of the City of Seattle Opposing the Proposed Rules, Recommending that they be Withdrawn, and Recommending Alternative Actions upon each of the parties on the service list compiled by the Secretary in this proceeding, by causing the Comments to be mailed, postage-prepaid, through the U.S. Mail.

Dated at Seattle, Washington, this 10th day of January 2003.

*/s/ Hazel Haralson*____________
Hazel Haralson