November 30, 2004

Mr. Brian Silverstein
Acting Vice President for Transmission Planning
Bonneville Power Administration
7700 NE Greenwood Drive
Vancouver, Washington
98662

Dear Brian:

Attached are Powerex's comments on **BPA's Transmission Adequacy Standards**: Planning for the Future, September 2004. We appreciate BPA's initiative in facilitating a regional discussion among transmission providers and customers and are pleased to have an opportunity to share our thoughts. We also support BPA's deadline of May 2005 for developing draft transmission adequacy standards. A summary of our comments is provided below, followed by more detailed answers to the specific questions raised in the Discussion Paper.

Transmission investments throughout the Northwest Power Pool region and the western interconnection have brought about significant economic and reliability benefits. The interconnection of transmission systems naturally results in interdependence -- it is a fact of "interconnected life" that the actions of any one utility impact others who are part of the interconnection. This interdependence, we believe, necessitates that Transmission Adequacy Standards be developed on a broad regional basis and more specifically, we recommend that the correct geographic scope of this effort be defined as the Northwest Power Pool or the Grid West footprint.

We appreciate the inherent difficulty in dealing with cost and risk issues, in particular how these are shared amongst various entities. This difficulty is most visibly highlighted by the fact that regional transmission solutions have been discussed for the greater part of a decade beginning with INDEGO. Although we understand that BPA does not want to replace or be dependent upon other efforts in the region, such as the RRG, we also question the value of examining similar issues in yet another forum consisting of very similar stakeholders. As a result, we would suggest that issues such as the sharing or allocation of costs and benefits, which is anticipated to be devised and implemented by Grid West, if not addressed in a timely manner in that forum, be discussed later in BPA's process. We think there is real value to be added through Regional Integrated Planning efforts whose primary goals are to identify beneficial transmission projects based on sound technical and economic criteria.

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With respect to the relationship between physical adequacy and economic adequacy, we conceptualize the issue somewhat differently than BPA has in its paper. Rather than two sets that intersect, we see the relationship as two dimensions within a three dimensional framework – transmission cost being the third dimension. We also believe there is a need to better understand what people mean by congestion, in particular in light of the current tariff and rate models being used in the Pacific NW.

In closing, we commend BPA for publishing this paper on Transmission Adequacy Standards. We believe that the timing is right to queue-up this discussion and that real value and understanding can be gained from this process. We look forward to participating in and supporting this effort.

Sincerely,

Doug Little
Vice-President
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Attach.

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Powerex's Comments on BPA's
Transmission Adequacy Standards: Planning for the Future

Draft Discussion Paper, September 2004

Questions raised by BPA in the Draft Discussion Paper on Pg 2:

- *The geographic scope of transmission planning and decision making. (Is it for BPA alone or the entire Northwest?)*

Powerex agrees with BPA's analysis on p. 8 and the implication that regional integrated planning will most likely lead to optimal solutions. This also leads to the implication that the geographic scope should be quite large to take into account the regional interactions of the interconnected transmission system. Consequently, Powerex believes the geographic scope should correspond to the Northwest Power Pool boundaries or the Grid West footprint.

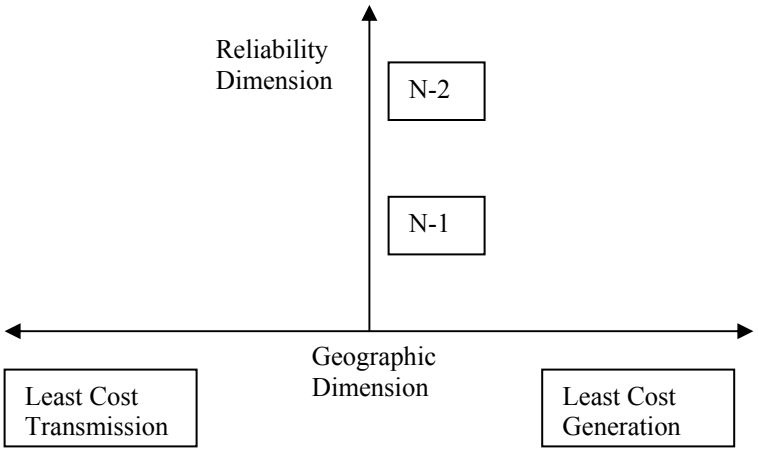
- *The costs and risks that utilities and customers are willing to assume for system reliability?*

It is not possible for utilities to eliminate the risk of curtailment for its customers. Consequently, each utility must strike a balance between acceptable curtailment risk and the costs of the transmission service. In Powerex's conceptualization, this attribute relates to the robustness or depth of reliability. However, a related characteristic is also system restorability. A major set of issues associated with the NE blackout was how long it took to restore the system to normal operating conditions. Powerex believes that it would be prudent to have safety-net schemes in place that will prevent system collapse or cascading blackouts – thereby enabling swift restoration following major outages.

A survey of NWPP members would reveal significant differences in how the balance between risk and cost has been struck to date and would inform this discussion.

- *The relationship between the physical adequacy of the transmission system and economic adequacy. (How much congestion is acceptable?)*

Powerex conceptualizes the relationship differently than BPA has portrayed it in the paper. We view this as two dimensions related to transmission, which can operate independently of each other. In one dimension, you have the depth of reliability which includes whether planners use an N-1, N-2, or other criteria. In the other dimension, there is a continuum between the least cost transmission system (i.e., the most geographically tight system that meets firm obligations according to whatever physical planning standard is used) and a least cost generation system (i.e., building sufficient transmission to integrate the least cost generation resources regardless of location while still applying the same physical planning standard). While it may be possible to reliably expand the transmission grid to incorporate other potentially cheaper generation sources, at some point the cost of transmission expansion will be more expensive than the generation benefit. This can be illustrated as show below:



In evaluating both dimensions, we need to define the obligation that is being met (i.e. load service obligation, firm contract obligation, etc.).

We could then add a third dimension, which is cost. The expectation is that cost increases as you increase the level of redundancy on the system and cost increases as you extend the geographic reach to integrate more generation. If both of those relationships were plotted, you could then construct the equivalent of a nomogram that would show the trade-off between the level of reliability and the extent of transmission system investment associated with each cost level. Our sense is that developing three dimensional perspectives for each zone of the NWPP transmission grid would yield valuable insight into the overall state of the transmission system.

The challenge facing the industry, as BPA has identified, is how to adequately make these trade-off calculations given the unbundling of the industry structure.[1] The region will need to develop new tools and metrics to ensure that we proceed with confidence as long-term transmission investments come up for review.

The term "Congestion" has taken on a variety of meanings, not only from the California energy crisis, but also from association with costs arising in the eastern power pools as a function of LMP pricing. However, in the context of the economic dimension, it really is a measure of the difference between the cost of the generation dispatch that the transmission system can reliably deliver and the least cost generation dispatch. The measurement of this cost and the tradeoff against transmission cost was historically undertaken by utilities during their least cost resource plan.

How much congestion is acceptable is a function of several variables including: frequency of occurrence, impact of congestion and the costs to relieve the congestion. Certainly, Powerex believes that if the costs to relieve congestion at a flowgate could reasonably be recovered through the incremental short-term firm and non-firm transmission revenue collected by relieving this congestion for a fixed period of time (i.e. five years) or other associated benefits, then the associated Transmission Provider(s) should take the necessary steps to relieve the congested flowgate.

Alberta has defined how much congestion is acceptable for their power system. Under Section 8(1)(e) of Alberta's Transmission Regulation[2] the Alberta ISO is required when making rules and exercising its duties under the Electric Utilities Act, to plan a transmission system that:
(i) is sufficiently robust to allow for transmission of 100% of anticipated in-merit electric energy when all transmission facilities are in service; and
(ii) is adequate to allow for transmission, on an annual basis, of at least 95% of all anticipated in-merit electric energy when operating under abnormal operating conditions.

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[1]How would the region handle some of the large projects of the past if they were presented today? For instance, could a large, multi-owner project such as Colstrip, with its long 500 kV lines used to integrate power into the Pacific Northwest, be built in today's deregulated environment? We think it would be a helpful exercise to understand what the critical roles were in historical large-scale projects and then consider who is best able to take on similar roles give the current market structures.

[2]The Transmission Regulation (AR 174/2004 enacted August 11, 2004) can be found at: http://qpsource.gov.ab.ca/database/REGS/2004_174.DOC.
The DOE's December 2003 transmission development policy in which the concept was initially introduced is available at http://www.energy.gov.ab.ca/ele/docs/transmissionpolicy.pdf. The discussion regarding reinforcement of the AIES such that ~95% of wholesale transactions can be realized without transmission congestion starts at p.8.

Key Issues

1. What are the standards by which adequacy should be determined? Is it physical adequacy (keeping the lights on) or economic adequacy (minimizing power cost and reducing price volatility caused by congestion)? Or, is it a combination of both?

As noted above Powerex believe these are two separate dimensions that each need analysis.

2. Are the current planning criteria and assumptions appropriate or should they be strengthened in the aftermath of the 2003 East Coast blackout? How robust should the system be? Should the region plan deeper for reliability than it does today, for example, planning for maintenance outages?

From Powerex's perspective the current planning criteria essentially divides up the transmission system into zones and determines if the firm transmission requirements associated with each zone can be met after the most severe single contingency has been taken during peak loading conditions. Our sense is that these criteria, when applied rigorously, provide the grid with margin to spare when loads are lighter or other lesser contingencies occur.

Applying this (single contingency) criteria becomes more complex in zones with multiple transmission providers, in particular when lower voltage transmission lines are in parallel with higher voltage transmission lines (e.g., 500 kV). In these circumstances, it is often difficult for transmission customers to know whether the root cause of transmission shortages is weak criteria or differing interpretations of the same criteria. To determine if the current physical adequacy criteria need to be strengthened it might be helpful to work through some specific examples of transmission constraints in the PNW and understand how all involved parties are currently interpreting the relevant criteria.

We believe that the robustness of the transmission system will vary by location as the costs of possible reinforcements and the economic impact of outages vary by location (i.e. the transmission system in northern BC is not as robust as the transmission system in Vancouver where three major sources (Peace Generation, Columbia/Kootenay Generation and US Intertie) are tied together). Nonetheless, it would be interesting to see if a regional robustness standard could be developed for the NWPP.

Powerex certainly believes that the region should plan for deeper contingencies as there are very few hours in the year that all lines will be in service. BPA's current practice is to rely upon intertie restriction (into/out of California, Canada and Montana) in order to mitigate for possible operating contingencies on its Network segment. Besides the obvious inequity of this "solution", frequently, this approach is only marginally effective as the root cause of the potential overload is not being targeted. We believe the most effective way to plan for deeper (or multiple) contingencies is through Special Protection Schemes.

It is important to utilize fully the flexibility found in the NERC planning standards, in particular for Category C Events resulting in the loss of two or more (multiple) components where the "Planned Loss of Demand or Curtailed Firm Transfers" are deemed acceptable. Often the probability of the next contingency occurring, such as a breaker failure or double line loss after a single contingency has already occurred, is quite low. Nonetheless, prudence requires addressing the risk and we believe that targeted schemes that trip either the most effective load or generation are cost-effective methods for reinforcement.

Additionally, system recoverability should be a characteristic that is analyzed. The lengthy process of restoring the grid to system normal following the NE blackout caused much of the economic costs, particularly in Canada as it took Ontario the better part of a week to remove the emergency condition. Safety Net Schemes that monitor critical voltages and flows should be put in place so that when Extreme Events (NERC Category D) do occur appropriate curtailments and/or separations take place. We believe that regional Safety Net Schemes will facilitate the goal of swift restoration following Extreme Events.

3. What metrics should be used to measure actual transmission performance so that we know if the grid is working as desired and when fixes are needed?

Performance metrics can be used to track progress in addressing systemic problems. Before we can develop appropriate metrics, we need to have a clear understanding of the systemic problems that need

to be addressed. Consequently, we are not sure at this stage which metrics would be most helpful, however, we believe that performance metrics should be based on accurate and accessible raw data that includes:

- hourly data of the limiting contingency and limiting facility for each flowgate in the NWPP;
- data on hourly OTC for each flowgate divided by the flowgate's seasonal rating;
- hourly data on the amount of transmission available to exchange operating reserves between the five NWPP reserve sharing zones;
- hourly data on firm and non-firm transmission curtailed in the preschedule timeframe;
- hourly data on firm and non-firm transmission curtailed in real-time;
- categorize contingencies for each flowgate into NERC Category B,C or D;
- data on on extent and duration of load curtailments;
- data on problems encountered during system restoration.

4. Should controlled load shedding be used to meet transmission adequacy standards? If so, what should be the acceptable loss of load for deeper contingencies?

Yes, controlled load shedding should be used to meet transmission adequacy standards. We propose that an acceptable loss of load standard would be:

- Outage Frequency of less than once in ten years; and,
- Expected Average Outage Duration of less than two hours.

5. What measures are considered in finding least-cost solutions to transmission limitations and who bears the responsibility for implementing non-wires approaches when these approaches are chosen?

The primary requirement is to have clear regional understanding of the elements that constrain the transmission system. By way of example, for each zone of the NWPP transmission system, it would be informative to know the *worst primary contingencies*, the *worst secondary contingencies* and the *worst limiting facilities*. With this detailed information it will then be possible to evaluate all possible solutions.

6. Who is responsible for ensuring an adequate system and who bears the cost? Should planning be done to meet load forecasts or only contractual obligations or should it be a combination of both?

The transmission provider is responsible for ensuring it has an adequate system. The question is adequate for what purpose? From the transmission provider perspective the minimum expectation would be adequate to meet its firm contractual obligations. Ultimately, it is the transmission customers who bear the costs of the requests that they make of the transmission providers. However, we believe that when there is significant congestion on a flowgate resulting in the curtailment of short-term firm and non-firm transactions, that this is a warning that the margin to provide for the firm obligations under the worst single contingency conditions has been eroded. Under these circumstances, it would be appropriate to review how the firm commitments are being planned for.

With regard to planning, a combination of obligations and forecasts is potentially the answer. Ultimately, the load serving entities have to make sure they have adequate resources to serve their obligations. These entities, or the parties delivering energy to them, must then make sure they contract for sufficient transmission to get the resources to the load. However, as noted in the paper, the time line for transmission infrastructure is far longer than generation resources. Plus the "chicken and egg" dilemma means without transmission you cannot get a Power Purchase Agreement (PPA), and without a PPA you cannot finance generation, let alone transmission. Part of the issue is also the lack of confidence that transmission will be built in a timely fashion to meet needs.

While transmission has a long lead time and is lumpy in size, the early work - in route selection, right-of-way acquisition (or optioning), consultation with stakeholders, etc. - is the relatively inexpensive portion of the project. Obviously, the critical variable is land cost as this can vary greatly depending on urban versus rural routing. Nonetheless, assuming that land cost can be managed, the other major costs (i.e. steel, wires & construction) are paid at the back-end of the transmission project. For instance for a 500

kV line from Nicola to Meridian (5L83) that BCTC is considering, expenditures in the first 5 years of this 10 year project represent 5% of the total estimated cost.[3]

Optionality should be included in the planning standards so that the time to completion of major transmission infrastructure is shortened. This will also require regulatory support in that capital will need to be spent to maintain in-service dates of projects that do not yet have firm customer commitments. At the end of the day for construction to proceed, long-term firm Network or PTP contracts might be required, but shortening the time horizon closer to that of generation resources would help to narrow the confidence gap. In order for this to work the planner must make some estimate of the load and resource options in order to determine what the potential critical path projects might be.

7. How should transmission adequacy be linked to resource adequacy? Since resource location is fundamental to meeting transmission needs, how should this be addressed?

Please see question 6.

8. How should market mechanisms be incorporated to address congestion and guide future resource siting and transmission investment decisions?

This is a fundamental rate design question that has tied up the region for the better part of a decade, dating back to the INDEGO efforts and continuing in Grid West. Powerex suggests that this debate continue to be played out in the Grid West forum. Introducing this debate into BPA's process will only distract from where the most value added can be gained. At a minimum, addressing this question should come at the end of BPA's process if progress is made on the other key issues.

Cost of Inadequacy

- *In addition to developing a redispatch protocol, should the region build facilities to avoid or reduce this congestion?*

Congestion in the Puget Sound Area and the PSANI[4] are of obvious interest to Powerex. It is our experience that South-to-North transmission constraints through the Puget Sound Area have been the subject of extensive discussions and technical effort. Potentially, the processes that have been focused on in the Puget Sound Area could serve as a model for solving transmission problems elsewhere in the NWPP geographical area. For this reason, it is worthwhile highlighting what has been achieved to date and our perspective on what should happen next.

Highlights:
- Detailed technical discussions of the Puget Sound Area transmission constraints amongst knowledgeable and creative representatives of interested parties;
- Comprehensive understanding of the operational constraints that result from single and multiple contingencies;
- Identification of an operational solution to some outages that otherwise would have resulted in significant reductions in OTC and possible PSANI curtailments;
- Identification of regional transmission reinforcement portfolios to reduce the risk of curtailments in the Puget Sound Area;
- Development of a redispatch protocol for winter 2004 to ensure effective coordination of generation resources during hours of transmission constraint;

Perspective:
The transmission system in the Puget Sound Area is particularly vulnerable to derates following a few single contingencies, and whatever standards are eventually developed for measuring congestion, we believe the Puget Sound Area will figure highly. Consequently, we believe that:

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[3] BCTC 2004 Capital Plan (http://www2.bctc.com/system/pdf/capital_plan.pdf), Table 3.2 or on page 103 of the document (Pg 118 in the Adobe reader).

[4] PSANI is an abbreviation for the Puget Sound Area and Northern Intertie curtailment scheme that BPA has put in place for hours when there is insufficient South-to-North transmission through the Puget Sound Area. BPA's intent is to ensure that if the Canadian Entitlement resulting from the Columbia River Treaty is curtailed that it will be curtailed on the same basis as BPA's other Pacific Northwest Customers.

- the low cost subtransmission and substation reinforcements that were identified as Portfolio #1 in the Puget Sound Area Upgrade Study Report[5] should proceed as soon as possible within the next 12 to 36 months;
- the rational redispatch procedures for the Puget Sound area should be reviewed and refined in 2005 in order to minimize the need for real-time curtailments of firm schedules.

- *While allowed by the planning criteria [the multiple outages that occurred on the southern Oregon coast this past winter], is this acceptable? Should the region invest more broadly in safety net schemes to minimize load loss during multiple outages?*

We believe that the root causes of these outages (i.e. secondary outages and limiting facilities) should be identified. Subsequently, a review of possible short-term and long-term solutions should be evaluated and cost estimates should be developed. In addition, the costs of these outages should be recorded so that a first-cut evaluation of the economic impact of these outages would be available to help answer questions about regional investment and aid in the design of effective safety-net schemes.

Summary

In the paper, BPA noted that synergies between transmission and generation planning have been lost as the electric industry deregulated. Regardless of what anyone in the Northwest may think of the current regulatory framework[6], as a region we must now plan for our interconnected future in light of the current open wholesale access environment.

The solution is not a return to the past, but a synthesis of the two paradigms. We believe that this effort by BPA along with others, such as NTAC and Grid West, can help lead the region to that synthesis.

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[5] Puget Sound Area Upgrade Study Report prepared by the NWPP NTAC (Northwest Transmission Assessment Committee) in Fall 2004.

[6] At times it seemed that the paper was nostalgic for the regulated environment of the 1970s and 1980s. We realize that there are a variety of opinions about the industry's move to deregulation, however, we believe it is important to remember that deregulation did not happen in a vacuum. Deregulation was a response to problems with the vertically integrated paradigm. Utility overinvestment, cost overruns, over forecasting of growth, spiraling debt loads, etc. led to high average rates, which led customers to pursue bypass options, which in turn caused rate death spiral, stranded costs, etc.

Ten years ago, real time prices were looked upon as signaling the true value of the commodity so that parties could make independent decisions on how to manage those costs. When expensive peaking units were averaged into rate base, demand-side programs had no basis to work. Real-time prices were a replacement for Time-of-Use (TOU) and other rate structures that were only an accounting approximation of the real value of energy at any given point in time. In other words, price visibility to market participants was being used to drive more economic decision-making, rather than relying on formulaic structures which inherently lagged or masked value signals. It is sustained high prices, whether averaged or not, which have adverse economic impacts. Price volatility in itself can be smoothed via contract methods without muting or masking the underlying economic signals.