B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

Transmission Adequacy Standards

Planning for the Future

Draft Discussion Paper

September 2004

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Transmission Adequacy Standards

Planning for the Future

Executive Summary

One of the challenges facing the electric utility industry today is how to balance reliability, economic, environmental and the other public purpose objectives to optimize transmission and resources to meet the needs of the region. These critical issues must be addressed to move the Northwest electrical system into the 21st century.

Resource and transmission adequacy are necessary components of a reliable and economic power supply. Achieving resource adequacy in today's restructured industry, where market economics and local concerns often dictate the siting of new generation facilities remote from major load centers, has made transmission planning extremely difficult. Equally difficult is planning for an adequate transmission system when the location of new generation facilities is uncertain and the lead time for transmission construction could exceed the time to build new generation by several years. Although reliability and market economics are driven by different policies and incentives, they cannot be separated.

The transmission system in the Northwest is pushing its limit. How does the region address an aging transmission network facing increasing demands? And how does the region factor in the risk and cost of outages such as the 1996 West Coast blackout (estimated cost: $2 billion) and the 2003 East Coast blackout (estimated cost: $10 billion.)

To address these needs, the Bonneville Power Administration launched a transmission infrastructure program in 2001. Six key projects will be completed by 2006 at a cost of more than $500 million. While this will add reliability and margin back into the system, it comes at a price. The added depreciation and interest expense related to these projects could push transmission rates up 14 to 20 percent. In addition, BPA has limited borrowing authority to finance capital replacements and expansion.

It is more important than ever for utilities to find a better way to determine how much transmission is needed, the solutions to be deployed and what criteria should be applied to guide prudent investment decisions. Key areas that need to be discussed include:

- The geographic scope of transmission planning and decision-making. (Is it for BPA alone or the entire Northwest?)
- The costs and risks that utilities and customers are willing to assume for system reliability.
- The relationship between the physical adequacy of the transmission system and economic adequacy. (How much congestion is acceptable?)

Towards that goal, BPA is initiating a public process to help develop the components of transmission adequacy and the standards to be used for decision making with the goal of testing these proposed standards by June 2005. Any comments on this discussion paper should be sent via e-mail to *tblfeedback@bpa.gov* or phone toll free 1.888.276.7790.

I. Introduction

Since its creation in 1937, the Bonneville Power Administration has been a cornerstone of the Northwest economy. It stimulated growth and new jobs throughout the region by marketing power at cost rather than at market prices. Following the passage of the Federal Columbia River Transmission System Act of 1974, the region has relied on BPA for much of its transmission needs.

For years, BPA has provided some of the lowest cost power in the nation. However, when the electricity market was deregulated, new forces came into play. New generation projects constructed by independent power producers, along with changing economics and volatile fuel prices, affected how power and transmission is managed throughout the industry. Change has continued unabated. Today, BPA and the region face questions as to how it can continue to maintain the current level of flexibility and service reliability at low cost.

Given the potential volatility in today's market, it is important that transmission utilities determine how much transmission capacity is required to meet regional needs and in what manner and then make prudent investments to meet their respective obligations.[1] A transmission adequacy standard is envisioned as a holistic framework for planning to meet reliability, safety, economics, environmental and other public purpose objectives. The foundations for these standards are the existing reliability criteria from the North Electric Reliability Council and Western Electric Coordinating Council, which are currently undergoing review. Adequacy standards would also encompass planning assumptions and economic objectives, some of which are not clearly documented. In addition, the adequacy standards and business conventions, such as tariffs, rates and business practices, must complement one another.

BPA is initiating a regional discussion on developing transmission adequacy standards to help gain regional consensus on a number of critical issues including:

- The geographic scope of transmission planning and decision making. (Is it for BPA alone or the entire Northwest?)
- The costs and risks that utilities and customers are willing to assume for system reliability.
- The relationship between the physical adequacy of the transmission system and economic adequacy. (How much congestion is acceptable?)

In this paper, BPA proposes a process and outlines concepts it believes are fundamental to regional transmission adequacy standards. The purpose of this paper is to seek ideas and concerns related to these concepts so that the region's stakeholders can be assured of a cost-effective reliable transmission system. It is not BPA's intention to impose standards on others. To the extent that there is regional agreement on new standards, it would be most effective if they can be universally applied. However, the objective of this paper is to explore ideas and options for BPA. Also, this effort is not intended to replace or be dependent on efforts to develop an independent regional transmission entity under the Regional Representatives Group.

[1] Forums such as Grid-West, the Seams Steering Group-Western Interconnection (SSG-WI), the Northwest Power Pool-Transmission Planning Committee (NWPP-TPC), the North American Reliability Council (NERC), the Western Electricity Coordinating Council (WECC), the Federal Energy Regulatory Commission (FERC) and others are working to address resource adequacy standards but *there is no clear definition of transmission adequacy*.

II. Issues

One of the challenges facing the electric utility industry is how to balance and optimize transmission and resources to meet the region's needs at least cost. Resource and transmission adequacy are both necessary for a reliable and efficient power system. Achieving resource adequacy in the restructured industry where market economics and citizen concerns drive the siting of new generation facilities is difficult. Equally difficult is planning for an adequate transmission system when the location of new generation facilities is uncertain and the lead time for transmission construction could exceed the time to build new generation by several years. Although reliability and market economics are driven by different policies and incentives, as indicated in Figure 1, they cannot be separated.

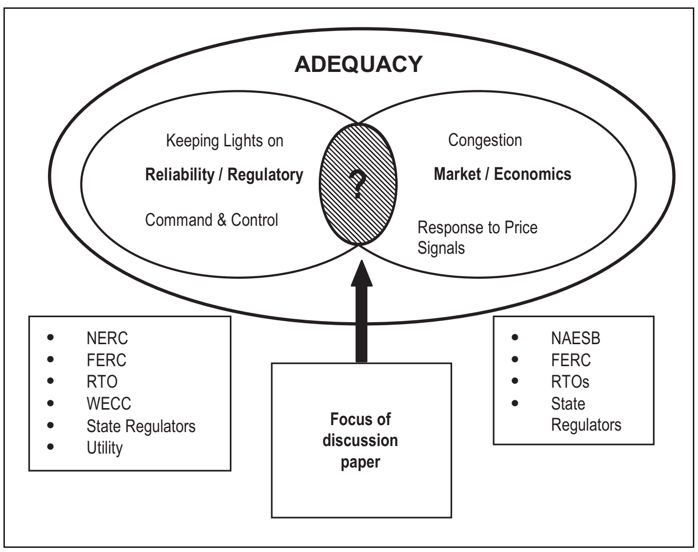

Figure 1: Adequacy: Reliability and Economics

BPA has identified the development of both resource and transmission adequacy standards as strategic goals because of the importance of an adequate power system to the Northwest. Because resource adequacy is currently being addressed in a number of forums, this paper focuses on transmission adequacy. BPA wants to work closely with key stakeholders in the region to develop a forward-looking strategy and to develop transmission adequacy standards that guide the region's future transmission decision-making and investments. Some of the key issues that need to be addressed include:

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?
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?
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?
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?
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?
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?
7. How should transmission adequacy be linked to resource adequacy? Since

resource location is fundamental to meeting transmission needs, how should this be addressed?

8. How should market mechanisms be incorporated to address congestion and guide future resource siting and transmission investment decisions?
9. Is the lack of symmetry in transmission financing policies, such as generators funding network upgrades and BPA funding construction for load service, a problem? If transmission providers finance transmission, who should assume the risk of generator shutdown and the lack of wheeling payments to cover costs?

III. Scope of this paper

There are at least two dimensions to the transmission adequacy issue:

- the geographic scope of the region's transmission adequacy assessment – BPA only or all of the Northwest
- the standards by which the region then determines transmission adequacy.

For BPA, this must be viewed within the context of its legal mandate under the Federal Columbia River Transmission System Act to "integrate and transmit electric power from existing or additional federal and non-federal generating units and BPA customers" along with maintaining "the electrical stability and electrical reliability of the federal system."

To develop adequacy standards, the first step is to understand and define "transmission adequacy" and how it should be applied within the transmission system. Then the drivers need to be understood, including:

- Obligations (load service and/or economic efficiency)
- Cost structure
- Market efficiencies
- Environmental impacts
- Other efficiencies including non-wires and new transmission technologies
- System maintenance
- Level of contingencies and desired performance

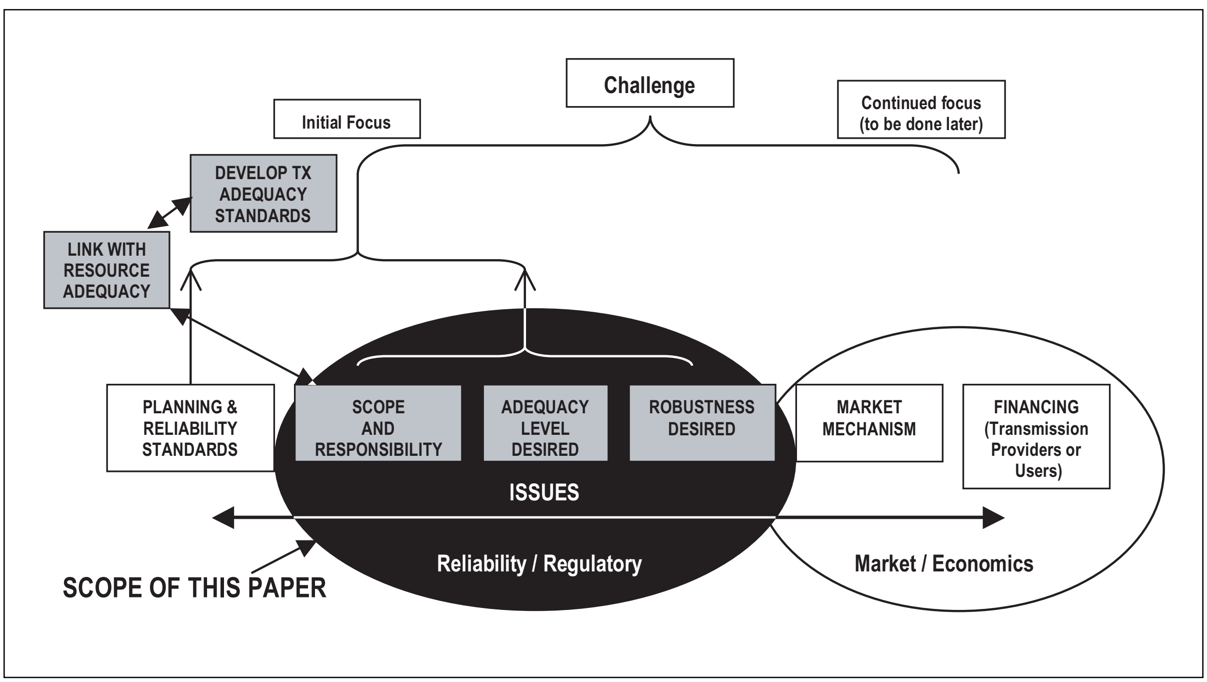

Figure 2: Strategy Map: Issue and Scope of the Paper

- Regional or inter-regional transfers
- Transmission and power rates
- Power quality

Once the drivers have been outlined, a set of consistent and measurable standards can be developed that can be used in transmission planning and the decision-making process. Figure 2 illustrates a phased approach to this process. This paper focuses on laying out the issues that need to be addressed for standards to be created (as shown on the left side of the diagram). A subsequent effort will be needed to understand and address market mechanisms and financing issues.

IV. Background

Development of the U.S. electricity system was considered one of the supreme engineering achievements of the 20th century. It now faces a daunting challenge in determining how to carry forward that same legacy into the 21st century. Generation capacity margins are declining, new transmission construction is down to the lowest levels in 20 years and transmission systems throughout the country are congested. The synergies that were once shared under the old vertically integrated utility paradigm have been lost. Power price volatility is affecting the overall economy. Major power outage events continue worldwide.[2] Maintaining transmission system reliability while supporting economic transactions is getting difficult and expensive.

Structural Changes

Throughout the world, the electricity industry has undergone deep changes in its structure (vertical separation of generation, transmission and distribution functions), ownership (participation of non-utility entities in transmission), electricity marketplaces and regulatory mechanisms.[3] These changes affect the way transmission systems are planned and operated, including BPA's system.

About 40 percent of power produced in the United States is from independent power producers. The transmission system is being used differently than its original design. In the past, transmission planners had operating strategies and prior knowledge of resource expansion plans and could incorporate that information when planning for transmission fixes. System requirements were driven more by reliability needs and less by market economics.

With deregulation, the roles and responsibilities changed (Figures 1 and 3) and are still unclear. This challenging environment makes it difficult to secure investments in new generation and transmission projects. Decisions are being driven more by market demands and economics. In BPA's service territory, many consumer-owned utilities that have historically relied on BPA to meet their load growth are now choosing to meet those obligations themselves. This leads to further uncertainty.

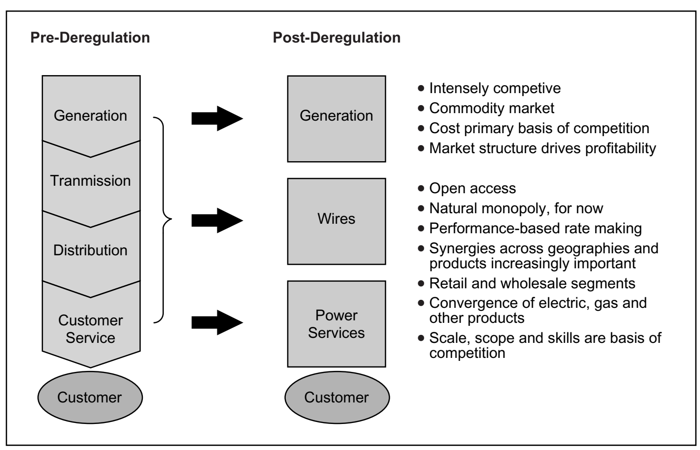

Figure 3: Changes In Electric Industry [4]

[2] Historical power outages in the U.S.: *ftp://www.nerc.com/pub/sys/all_updl/docs/blackout/BlackoutTable.pdf*.
[3] R. Nadira, R. Austria, C. Dortolina, and F. Lecaros (July 2003). "Transmission planning in the presence of uncertainties." Proceedings of the IEEE 2003 PES General Meeting, Toronto, Canada.
[4] William J. Heller, Paul J. Jansen, Lester P. Silverman (1996). "The New Electric Industry: What's at Stake" (McKinsey Quarterly).

Transmission providers could make decisions that may not necessarily meet the requirements of the competitive market. With market failures in some jurisdictions, people are questioning deregulation and advocating for reintegration.

Cost of Inadequacy

Congestion is the "cholesterol" of the transmission system. It blocks the power arteries and puts stress on the system and can result in a major power breakdown.[5] Congestion has allowed for market manipulation, as in the California energy crisis.

The transmission system in the nation is pushing its limit. Wholesale power transactions canceled due to overloaded lines rose five-fold from 1998-2002, and the cost of transmission congestion nationwide is on the rise.[6] A similar situation exists in the Northwest. Since 1987 no new major transmission line construction was built in the Northwest until BPA began its infrastructure initiative in 2001.[7] This has resulted in stagnant or declining transmission capacity and created significant congestion points throughout the system. The transmission operators and regional coordinating councils have done well to keep the system safe and reliable, sometimes at a price of uneconomic operation. How long can this be sustained in an era of aging transmission networks and increasing demand?

In the Puget Sound area, load growth and return of the Canadian Entitlement coupled with multiple transmission outages on several occasions to trigger a curtailment procedure called PSANI. While no load has been lost, in some cases utilities needed to adjust schedules and incurred additional costs to purchase higher priced resources. A coordinated regional redispatch protocol would reduce costs over individual actions and provide better protection against load loss, but utilities have been unable to reach agreement on cost allocation responsibilities. In addition to developing a redispatch protocol, should the region build facilities to avoid or reduce this congestion?

Chronic congestion leads to increased price volatility. Tools to estimate the number of hours a year that congestion might occur, or more importantly, what the costs are related to this congestion are beginning to be used. However, they have limitations for hydro-based systems. These costs are difficult to benchmark without good historical data. Regions with tight operating pools, regional transmission organizations or an independent system operator have a good feel for the cost of congestion. But none of these institutions operate in the Northwest. Re-dispatch protocols under the BPA tariff have only been implemented for limited situations. And, finally, there is no well-defined threshold for chronic congestion that triggers the need for reinforcement.

The financial losses from blackouts can be significant as indicated by the 1996 West Coast outage (estimated $2 billion) and the 2003 East Coast outage (estimated $10 billion). This past winter, multiple outages during winter storms caused blackouts on the southern Oregon coast. While allowed by the planning criteria, is this acceptable? Should the region invest more broadly in safety net schemes to minimize load loss during multiple outages?

Before adequacy standards are developed and implemented, it is important to understand the risks associated with either under or over specifying transmission adequacy (Appendix B).

[5] Elliot Roseman (Principal ICF Consulting). "Getting Necessary Transmission Build: The Value of Reliability and Loss Load."
[6] Elliot Roseman (Principal ICF Consulting). "Power Crisis: Omission of Transmission. An issue paper on the U.S. Northeastern Blackout, Aug. 14, 2003."
[7] For more information on BPA's infrastructure program go to *www.transmission.bpa.gov/Business/Customer_Forums_and_Feedback/Programs_in_Review/PIR2004.cfm*.

Economic Trade-off

To address these needs, the Bonneville Power Administration launched a transmission infrastructure program in 2001 to respond to transmission constraints. Six key projects will be completed by 2006 at a cost of more than $500 million. While this will add reliability and margin back into the system, it comes at a price. The added depreciation and interest expense related to these projects could push transmission rates up 14 to 20 percent. In addition, BPA has limited borrowing authority to finance capital replacements and expansion.

Transmission costs today represent about 8 percent of a Northwest residential consumer's energy bill. Could a modest increase in investment in this area reduce consumers' total energy costs? The goal is to develop an optimized transmission grid where overall costs and environmental consequences are minimized.

V. Defining transmission adequacy

An adequate transmission system is required to maintain acceptable levels of reliability, stability, security, lower wholesale power cost, and to reduce economic impact due to transmission-related outages. Defining an optimum amount of transmission capacity is a time-dependent concept and a function of locations, magnitudes of resource and demand, the configuration of transmission grid and possible contingencies that affect flows on the transmission system.[8]

Planning assumptions and shortcomings of the process

Planning for a transmission system is difficult irrespective of whether the industry is vertically integrated or deregulated. All three components of the industry (resource, transmission and distribution) along with the loads are strongly coupled from a functional viewpoint.[9]

Planning is still done mostly on a deterministic criteria basis. The system is tested using power flow, voltage stability and transient stability analysis against a set of contingencies from NERC, regional and sub-regional standards. Probability methods are used on a limited basis in WECC to obtain exemptions for multiple contingencies. Planners look at a snapshot or a few scenarios while conducting planning studies that analyze and plan for transmission system improvements, ranging from small system upgrades to capital-intensive large transmission line projects. (See Appendix A for BPA's Planning Process.)

Utilities also perform studies to identify transmission limits taking into account near-term system operating conditions. These constraints may require limiting transmission use, generation patterns and arming more automatic remedial action schemes (RAS) to protect the system. Chronic operating problems can help identify the need for system reinforcements. Since operating and planning studies have different purposes, it is important that a transmission adequacy standard include both time frames.

How robust should the system be?

From a planning standpoint, a transmission system is considered reliable if it complies with NERC and regional reliability standards. However, in actual practice systems generally operate in a state with one or more elements out of service due to maintenance, construction or forced outages. It has become nearly impossible to take equipment outages to maintain or enhance the grid without affecting the economics of the power system. The

8 Hirst, Eric (August 2000). "Expanding U.S. Transmission Capacity."

9 Ramon Nadira, Ricardo R. Austria, Carlos A. Dortolina, Miguel A. Avila (2004). "Transmission Planning Today: A Challenging Undertaking." The Electricity Journal.

shortcoming of this process is that the robustness of the transmission system is not known until the operating studies are conducted or when problems are actually experienced. By this time, it is too late to provide for an effective fix other than instituting operating procedures to manage the system and maintain reliability. This limits the ability to maintain capacity with a high level of confidence across the constrained paths.

Adequacy is evolving from a deterministic engineering assessment of reliability to a broader perspective that addresses congestion and market mechanisms. So is the standard simply that, under specified conditions, adequate resources must be available no matter what the price? Should commercially significant congestion trigger reinforcement? The question is how robust should the system be?

Planning from a "one-utility" perspective

The transmission grid operates according to the laws of physics without regard to ownership or contractual rights. Therefore the "one utility" least-cost perspective (plan the interconnected system as if it was owned by one utility) should lead to optimal solutions. It ignores equity issues concerning which transmission provider is responsible for fixes. A stalemate could result because of disagreements between transmission providers. This may result in an inadequate transmission system (and unacceptable congestion) or the potential of over investing in the transmission system by a single transmission provider making a less optimal fix. A reliable and secure transmission system requires consistent transmission adequacy standards that are uniformly applied across the system. However, when it comes to making investment decisions, commercial considerations come into play.

Today transmission reliability and commerce are tightly integrated. While some of the other industries, such as natural gas, work on similar principles, they are fundamentally different from the transmission system. Transmission systems must continuously balance load and resources within a specified tolerance level. If balance is not achieved, reliability is impacted. In addition, under the laws of physics, the flow of electrons cannot be freely controlled. This means that a problem on one part of the system can catastrophically impact the rest of the system. That was clearly demonstrated in the Aug. 14, 2003, blackout on the East Coast.

Building and financing new transmission infrastructure

Today there is a large disconnect between how much time is needed to build large generation and the time needed to site and construct transmission lines. Due to resource availability, a large number of gas and wind generators now are being placed further away from load centers, making it more difficult to provide transmission.

Transmission investment is inherently "lumpy." To achieve acceptable economies of scale, a single project is often costly, sometimes exceeding $100 million, and might result in more incremental capacity than the market can immediately absorb. Aggregating sufficient new contracts, primarily from new generators, to cover the incremental costs of new transmission is very difficult to do in the current market environment, especially when advance financing from the developer is required.

A related problem is how to build transmission lines for new generation projects when the same new generation projects are often unable to secure power sales contracts until they can demonstrate they have obtained firm transmission. On the other hand, without a power purchase agreement they are unable to finance the needed transmission expansion required by most transmission providers. This chicken-and-egg dilemma stifles new transmission investment. Even if the transmission providers were resolved to invest liberally in new transmission projects absent signed contracts, this creates risks for existing customers and siting becomes more challenging without a clear and immediate benefit.

Integrating non-wires solutions

Given the cost and environmental consequences of transmission siting, BPA is integrating non-wire solutions,[10] such as demand response, distributed generation and conservation into its planning process and its portfolio of transmission solutions. A number of technical and institutional issues are being addressed to ensure that these measures are viable solutions.

VI. A strategy for moving forward

The proposed strategy is to assess and identify deficiencies in BPA's and the Northwest region's existing processes and standards for planning for an adequate transmission system. Based on these deficiencies, existing standards can be refined and additional elements developed. Because of the interconnected nature of the electric grid, transmission adequacy standards would be most effective if the standards were applied across all transmission in the Northwest. If this cannot be achieved, a BPA standard must be developed with input from all stakeholders.

Proposed strategy

BPA is not proposing a solution or even alternatives at this time. Instead BPA invites an open and thorough dialog. To assist in the discussion, possible elements of an adequacy standard are listed in Appendix C.

As an initial step, the Northwest should begin a public process to help define the components of transmission adequacy. This process could involve creating a task force with members from the utility industry and key stakeholders. Work of the task force would then be shared on a regular basis with regional transmission providers, retail utilities, independent power producers, generation developers including renewable projects, Northwest tribes, regulatory bodies, state governments, the Northwest Power and Conservation Council, the Western Electricity Coordinating Council, environmental organizations and the general public.

The process would help shape the issue and create awareness among the affected parties.

The objective would be to develop draft transmission adequacy standards by May 2005.

The next phase would be to test these draft standards in a wider arena, gain regional acceptance and ultimately implement them, as illustrated in Figure 4.

Certain potential elements, as listed in Appendix C, could be part of the standards. The full development of such standards or metrics may require an independent or impartial entity to apply and verify compliance. The current Grid-West proposal calls for the establishment of such an independent entity. However, there may be alternative approaches.

[10] *http://www2.transmission.bpa.gov/PlanProj/nonconstruction.cfm*

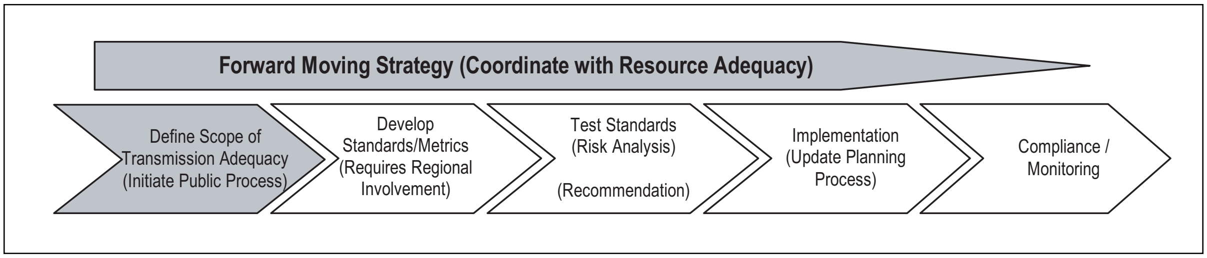

Figure 4

Proposed schedule

Below is a proposed timeline for moving forward on the development of transmission adequacy standards:

- Sept. 28-29, 2004 – Discuss concepts at *Energizing the Northwest, Today and Tomorrow.*
- October to mid-November 2004 – Comment period on discussion paper and process.
- Mid-November to May 2005 – Develop proposed standards.
- June 2005 – BPA and key stakeholders begin to test proposed draft standards with public involvement process.
- September 2005 – Comment period closes.
- December 2005 – BPA decision on standards.
- January 2006 – Transition to standards.

To comment

If you would like to comment on this discussion paper or proposed process, please e-mail *tblfeedback@bpa.gov* or call toll free 1.888.276.7790.

Acknowledgements

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Appendix A
BPA's Existing Transmission Planning Processes

Definition – The planning process includes developing a long-term plan, generally greater than one year, for acceptable reliability (adequacy[11]) of the interconnected bulk electric transmission systems within its portion of the planning authority area.[12] See Figure A1 for a simplified version of the transmission planning process.

Planning Process

1. BPA planners examine the grid under the "one-utility" concept, as if the grid was owned and operated by a single entity. If problems are identified, BPA works with affected utilities to identify a best "one utility" plan and then move into commercial negotiations to allocate benefits and costs.
2. Planning studies are performed using standard industry rules and practices. System performance is tested against North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC) and BPA reliability standards using power flow, transient stability and short circuit analysis. Probability methods are being used on a limited basis to obtain adjustments (exemptions) to the system performance required for multiple contingencies.
3. System modeling for planning studies includes, but is not limited to:

- Generally, the planning process includes studies up to five (or more) years into the future and responds to load growth and generation siting.
- Planners look at scenarios to capture a range of possible system conditions.
- The transmission grid is modeled with loads as forecasted by the other utilities and BPA staff. For most load service solution, the business case analysis assumes a cost recovery mechanism is in place.
- Generation is modeled with historical stressed patterns for the season represented. Interties and transfers are set at levels that stress the system. However, BPA's methodology is evolving. For example, for long-term firm transmission service requests, BPA models imports from BC Hydro at the firm obligation level, not the maximum path rating. (See item #8.)

4. Planners screen and evaluate system performance for future needs, as identified by various drivers[13], for the existing transmission system.
5. The identified problems include violations of, but are not limited to, voltage magnitude, transient stability and appropriate facility thermal ratings.
6. A plan of service is selected based on economic analysis, developing the least cost alternative that complies with NERC and WECC planning standards, and inputs through regional planning process (NWPP-TPC) and environmental impact statement.
7. Identified problems are mitigated by upgrading or adding facility(s), developing system protection (e.g., remedial action schemes) needs, communication and control needs, and other requirements (e.g., developing

[11] *Adequacy:* There is no clear definition for adequacy. However, based on the NERC definition, adequacy is defined as: "Interconnected transmission systems shall be planned, designed and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions."

[12] NERC Reliability Functional Model. November 2003.

[13] Drivers include: generation interconnection, load growth/reliability needs and other statutory requirements.

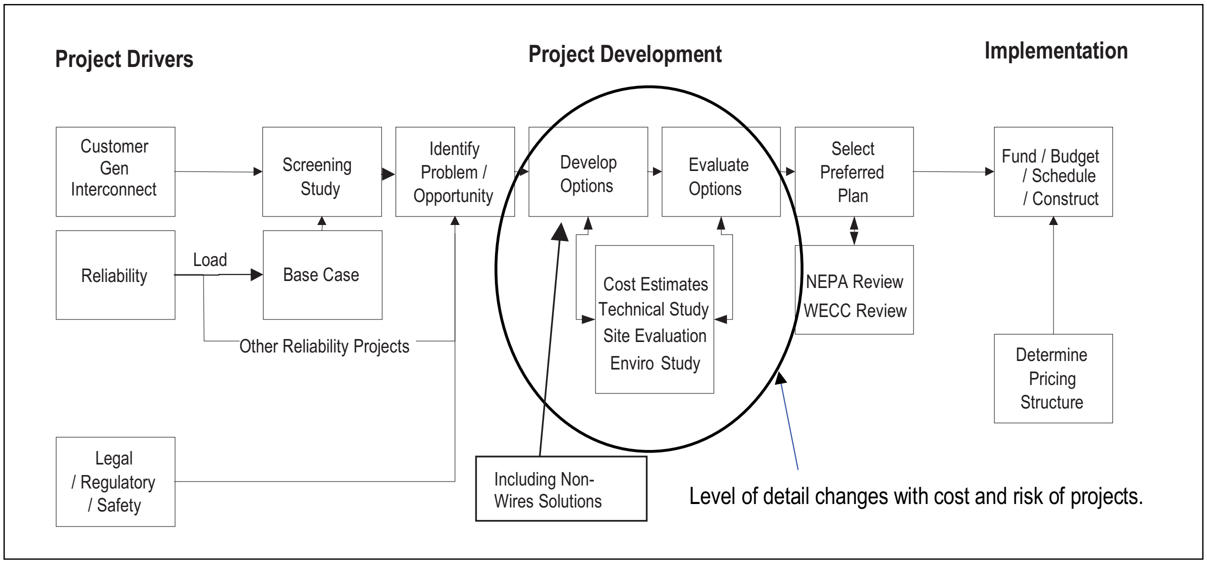

Figure A1: Existing Planning Process [14]

operating procedures), in compliance with all applicable reliability standards.

8. BPA's new Available Transfer Capability (ATC) requires BPA to recalibrate its planning assumptions. Network transmission (NT) rights and other contracts also affect how the federal hydro is dispatched. In addition, BPA may only represent Northwest generation at levels representing firm transmission obligations on BPA or third-party systems.

9. The recent Aug. 14, 2003 East Coast blackout and subsequent recommendations for the Canada-U.S. investigation into the outage will likely change the standards for planning.

Figure A1 shows a simplified version of BPA's Transmission Business Line's existing transmission planning process. While designed to meet the anticipated needs of its transmission customers, the process is reactive since it is almost always driven by events external to the transmission provider. These events are called project drivers and include requests for generation or customer interconnection or the need to comply with legal, regulatory, safety or reliability requirements. These drivers then lead to screening, evaluation, development of options (including non-wires solutions), selection of the preferred technical plan, various reviews to ensure compliance with NERC and WECC reliability requirements, regional planning processes under WECC and NWPP and with the National Environmental Policy Act and finally an implementation process that includes construction and rate-making.

[14] Ren Orens, Snuller Price, Debra Lloyd [Energy and Environmental Economics, Inc.]; Tom Foley, Eric Hrist [Consultant] (Novemeber 2001). "Expansion of BPA Transmission Planning Capabilities." (Figure changed to include non-wires solutions and update the process including the drivers.)

Appendix B
Risk Factors

Additional risk factors to consider including, but not limited to:

- Changing economic conditions
- Core industry dislocations (such as the demise of aluminum smelters)
- Competitor activities (for example, new transmission in adjacent regions)
- Escalating fuel costs and/or long-term structural changes in relative costs among fuels and between regions
- Business risks such as uncertainty, cost recovery, transmission pricing structure, financing and rate of return
- New technology and cost effectiveness
- Market response to institutionalized fixes such as demand response and distributed generations (non-wires)
- Market structure (LMP, others)
- Ownership structures – for-profit transmission companies (Path 15) may demonstrate efficient use of capital and efficient use of the marketplace
- Land costs, siting requirements, EIS, public opposition
- Regulatory changes – slower approval response
- Transmission versus generation (cost of building)

Appendix C
Potential Elements of a Transmission Adequacy Standard

Reliability Standards
- NERC, WECC and BPA standards
- Explicit performance criteria such as LOLP
- Probabilistic criteria
- Robustness tests
- Extreme event tests

Economic Standards
- Societal benefit/cost analysis of reliability – value of load loss
- Acceptable levels of congestion
- Definition of least cost solutions
- Price volatility and tolerance
- Assurance level for maintaining Available Transfer Capability across flowgates

Expansion and Pricing Policies
- Drivers
  - Generation
  - Load
  - Transfers into, out of and through the region
  - Flexibility
- Financial
  - “Or” test for pricing expansion
  - Advance financing requirements or other risk management tools

Other Public Purpose Objectives
- Development of renewable
- Resource diversity
- Economic development
- Seasonal products

Possible Solutions
- Amounts and obligations for Remedial Action Schemes
- Re-dispatch (mechanisms)
- Curtailment strategies
- Non-Wires Solutions
- Locational Marginal Pricing (LMP)
- Changes to maintenance practices to provide for more flexibility
- Better load forecast mechanisms
- Investigate and incorporate new technologies
- Better computer tools to assess state of the transmission system in real time