May 11, 2012

Via Electronic Submission
Bonneville Power Administration
techforum@bpa.gov

Re: Comments of Point to Point Customers Coalition to Bonneville Power Administration's Proposal to Use a 12 NCP Method for Allocating Transmission Service Costs.

The Point to Point Customers Coalition ("Coalition")[1] submits these comments on the recommendation dated April 26, 2012, of Bonneville Power Administration ("BPA") staff that BPA use the 12 non-coincidental peak ("NCP") method for allocating network costs. The Coalition thanks BPA for the opportunity to comment and looks forward to continuing to work cooperatively with BPA to determine an appropriate methodology for the allocation of network costs.

We appreciate BPA's attempt to propose a cost allocation methodology for transmission service for the BP-14 rate case. However, BPA staff's proposed 12 NCP method is inconsistent with how BPA plans its transmission system and should not be adopted. BPA should continue discussions with its customers in the pre-transmission rate case workshops or separate workshops to align the cost allocation methodology with BPA planning, operations and cost causation principles. At this point, any recommendation on this issue is premature.

I. BPA Should Not Determine a Cost Allocation Methodology.

Network Integration ("NT") and Point-to-Point ("PTP") transmission customers clearly disagree on the appropriate network cost allocation methodology. BPA should allow additional time for stakeholders to investigate network cost allocation methodologies and present their positions to BPA staff prior to any recommendation. For example, the Coalition has come upon new information, including Western Electricity Coordinating Council ("WECC") regional planning standards and coincident and non-coincident calculation methodologies that require further investigation.[2]

[1] The Coalition includes Benton County Public Utility District No. 1, EDP Renewables, Franklin County Public Utility District No. 1, M-S-R Public Power Agency, Pend Oreille Public Utility District No. 1, Powerex, Seattle City Light, Snohomish County Public Utility District No. 1, and Tacoma Power. For purposes of these comments, the Coalition also includes Avista Corporation and Puget Sound Energy, Inc.

[2] Snohomish has retained Philip Q. Hanser, a principal with the Brattle Group and an expert in the cost allocation of transmission service who will provide valuable input to the process of determining a cost allocation methodology. Snohomish is willing to make Mr. Hanser available to answer questions and present FERC approaches at a future workshop.

II. The Cost Allocation Methodology Should Follow Planning Principles.

The Coalition agrees with BPA and FERC that planning should be the basis for cost allocation. The proposed 12 NCP method is not consistent with the manner in which BPA or WECC plans for transmission.

A. Regional Planning and BPA

The Coalition understands that BPA plans its system consistent with North American Electric Reliability Corporation and WECC Planning Standards. WECC base cases focus on NCP heavy and light load conditions for the summer and winter seasons as well as the spring cases that address transitions from winter to summer that are often used to address high hydro conditions. The variations in load characteristics are modeled to address system peak load and system low load in order to develop boundary conditions that reveal system adequacy when peak load conditions are coupled with both high and low transfers. In the Northwest, the winter demand can typically cover a four- to five-month period, meaning a system may hit its winter peak anytime between the first of November through the end of March. The Coalition also understands that the WECC sub-regional planning coordination effort requires electric utilities, including BPA, to review and submit NCP demands for specific seasonal base cases.[3]

In short, WECC uses base cases that focus on NCP and the summer and winter seasons, which are then further tailored to account for seasonal temperatures.

B. A 12 NCP Method Is Not In Line with How WECC or BPA Plans Its System.

BPA has not demonstrated that it plans its system on the basis of its customers' 12 non-coincident peaks. To the contrary, the evidence shows that BPA plans its system and incurs costs on a 1 NCP basis (i.e., BPA's planning essentially focuses on winter and summer peaks). In its presentation titled "Transmission Cost of Service Analysis Workshop" dated February 8, 2012, BPA explained that it "plans the transmission system so it will operate reliably to meet its obligations" and that it "models normal non-coincidental summer and winter peak load conditions, as well as some other conditions as off-peak or heavy winter."[4] Maintaining reliable operation of a transmission system ultimately requires that the system operator plans in a way that ensures that the level of maximum (peak) demand can be reliably served by the system. To achieve that goal, the system planner will typically rely on a single point estimate, 1 coincidental

[3] The sub-regions in WECC include: 1.Northwest Power Pool ("NWPP") – Canada and NWPP – US; 2. California-Mexico – CAMX; 3. Desert Southwest; and 4. Rocky Mountain Reserve Area. (*See* Attachment A). Loads are often weather adjusted in order to identify sub-regional demands. In the case of the Northwest, loads are highly sensitive to seasonal temperature. Analysis of historical temperature data is often used to project summer and winter temperatures. In cases where historical temperature data is limited; the use of Normal or Gaussian distribution techniques can be used. An example may include a 1 in 2 year temperature condition, which identifies a temperature that would have a 50% probability of occurrence. The BPA "Reliability Criteria for System Planning" that was distributed at a Northwest Power Pool ("NWPP") Transmission Adequacy Workgroup ("TAWG") meeting in 1996 and referenced by BPA as recently as 2006 included the following: a "Normal Cold" 50% probability of occurrence, "Intermediate Cold" 20% probability of occurrence (1 in 5 year occurrence), and an "Abnormal Cold" 5% probability of occurrence (1 in 20 year occurrence) (*See* Attachment B).

[4] BPA "Transmission Cost of Service Analysis Workshop," February 8, 2012 at slides 10-11.

peak ("CP") or 1 NCP. As a result, the cost incurred in building and maintaining a reliable transmission system can be directly traced back to the impact of maximum demands.

As explained on slide 3 of BPA's presentation titled "Transmission Cost of Service Analysis Workshop," dated April 26, 2012, costs would be allocated under the 12 NCP method "based on PTP, IR and FPT annual average forecasted contract demand plus the sum of each NT customer's average monthly noncoincidental peak." However, under the 1 CP method, costs are allocated using a divisor that includes the coincidental annual peak NT sales to allocate costs, whereas the 1 NCP methodology uses a divisor that includes the sum of each NT customer's noncoincidental annual peak to allocate costs.

The conceptual difference between the 1 CP and 1 NCP approaches on one hand and the 12 NCP approach on the other is very important. In essence, the use of 12 monthly peaks results in an estimate of network usage that is *lower* than the annual peak because it *averages* peak demands over the 12 months. By increasing the number of monthly peaks included in the calculation, the average (i.e., 12 peaks) will fall because many (presumably all) of the included peak values will be less than the maximum (i.e., 1 peak). Only if each and every monthly peak was identical would this not be the case—a situation that empirically is not the case. As discussed above, building and maintaining a reliable transmission system requires that the network be built to withstand the highest expected (i.e., maximum level of) demand. Consequently, costs that are incurred to ensure transmission reliability are directly related to maximum—not average—demands. BPA's proposal to adopt a 12 NCP cost allocation methodology for its network segment contradicts the cost causation principle of rate design and will result in allocating costs to customers in an unfair and inequitable manner.

The Coalition notes that BPA has argued in the past that a 1 NCP method was appropriate.[5] It is not clear what factors have changed in BPA's planning that would justify a 12 NCP cost allocation method. To the extent there is evidence that may support alternative network cost allocation methods, the Coalition is willing to work with BPA and other customers in reviewing them.

III. BPA Should Not Rely on the FERC Cost Allocation Tests as a Basis for a 12 NCP Method.

The Coalition has previously explained that the FERC cost allocation tests do not take into account the uniqueness of BPA's role as a Transmission Owner/Operator. Approximately

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[5] *Bonneville Power Administration's Petition for Declaratory Order Regarding Rates for Open Access Transmission Service and an Exemption in Lieu of the Application Fee*, Docket No. NJ97-3-000, p. 29 (December 20, 1996).

> It is appropriate to use the one-noncoincidental demand method for the load-based NT service because it most closely resembles the contract demands used to assign costs to other classes, and it reflects how BPA plans its transmission system. BPA planning studies look at a winter condition with loads equal to the sum of the utilities' annual noncoincidental demands. BPA also plans for a summer peak on the parts of the FCRTS where peak loading conditions occur in the summer []. This cost allocation approach was agreed to by the parties in the Transmission Settlement.

80% of BPA's transmission customers are Point-To-Point, Integration of Resources and Formula Power Transmission rate customers. This means that about 80% of BPA's transmission service is associated with reserved capacity as opposed to usage. This ratio between reservation- and usage-based customers biases the FERC test results toward a 12 CP methodology. It is also important to note that the FERC-jurisdictional utilities cited in NT customer comments with the intent to demonstrate that 12 CP is the standard allocation method provide much more NT service than PTP service.[6]

	Monthly Peak (adj[7])	Network	L-T PTP and Other
Avista	20,895	18,841 (90%)	2,054 (10%)
Idaho Power Company	51,992	44,705 (86%)	7,287 (14%)
PacifiCorp	165,629	100,782 (61%)	64,847 (39%)
Portland General Electric	10,810	8,776 (81%)	2,034 (19%)[8]

Thus, the FERC tests should not be applied to service on BPA's transmission system. As explained in prior comments, there is no "one size fits all" cost allocation methodology. FERC has recognized that alternative allocation proposals may have merit and welcomes them.[9] In Order No. 888, FERC reaffirmed the use of the 12 CP method only because it believed the majority of utilities planned their systems to meet their twelve monthly peaks.[10] As was the case in 1996, and is the case now, BPA does not plan its system to meet its twelve monthly peaks.

IV. The Coalition Is Unclear How Surplus Marketing and Integration of New Resources Lead to a Finding that 12 NCP Is Appropriate.

BPA has stated that there are factors besides the annual-peak loads, such as surplus marketing and integration of new resources, that have driven BPA to recommend a 12 NCP. The Coalition requests that BPA explain the nexus between these factors and the formation of a cost allocation recommendation.

V. BPA Must Meet Its Statutory Mandate to Allocate Costs Between Federal and Non-Federal Power Utilizing the BPA Transmission System Equitably.

The Coalition submits that any cost allocation method that is inconsistent with BPA planning practices would result in an arbitrary and inequitable allocation of costs – a violation of Section 10 of the Transmission System Act. Therefore, BPA should re-evaluate its cost allocation recommendation consistent with planning and operations.

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[6] The Coalition is gathering information on the non-FERC jurisdictional utilities also cited by NT customers and will share that information as soon as available.

[7] Short-term PTP and "other services" were excluded from these reported monthly peaks loads.

[8] *See* each respective company's FERC Form 1, p. 400 (2011/Q4).

[9] Order No. 888 at 31,736.

[10] *Id.*

VI. BPA Should Not Adopt a 12 NCP Simply Because It May Be a Compromise Between Proposals.

BPA should only recommend a cost allocation method that has a cost-of-service basis and not a method that reflects a compromise between competing proposals. The cost allocation method must be consistent with how BPA plans and operates its system. A compromise cost allocation methodology not based on facts and that is inconsistent with BPA's planning and operating practices will fail scrutiny.

VII. Peak Allocation Methodologies Should Not Be Limited to Use of Peaks From Consecutive Months.

As discussed above, BPA should adopt a 1 NCP methodology. However, if BPA were nevertheless to adopt a methodology based 2 or 3 monthly peaks (e.g., 3 CP), it should be recognized that those monthly peaks need not be consecutive months or months limited to a particular window during the year.

Slide 9 of the presentation titled "Transmission Cost of Service Analysis Workshop" dated April 12, 2012, states that "[i]n developing the relevant period for 3 CP analysis, the forecast NT demand for three consecutive months in each year of the rate period was used." BPA need not use consecutive months in its peak allocation methodology. For example, a 3 CP method can and should use data for months with significant expected peaks—such as a summer and winter peak—and which will be part of the projected period over which rates are calculated. Indeed, in the 3 CP method, requiring that the peak calculation method be based on consecutive months is equivalent to asserting that the second and third highest monthly peaks always occur within a three-month window. This is an unnecessary restriction that could well result in failing to include the actual second and third highest monthly peaks during the year. In fact, slide 5 of the presentation titled "Transmission Cost of Service Analysis Workshop" dated March 7, 2012, states that the 3 CP method is similar to the 12 CP method but instead relies on "the highest value in the 3 months of highest use. These are typically but not necessarily consecutive months."

VIII. The NT MOA Identifies a "Capacity Reservation" Quantity for NT Customers.

BPA was requested to provide information regarding the nameplate capacity of each designated Network Resource identified on Exhibit A to BPA's Memorandum of Agreement for the Management of Network Integration Transmission Serviced for Delivery of Federal Power Network Customer Loads, posted by BPA on September 30, 2011 (the "NT MOA"). On May 7, 2012, BPA suggested that this information could be found on Tables 4 and 5 of the 2011 Pacific Northwest Loads and Resources Study.[11]

The NT MOA appears to be an approach unique to BPA that identifies a "capacity reservation" quantity for NT customers comparable to the capacity reservation for PTP

[11] *See* Tables 4 and 5, of the 2011 Pacific Northwest Loads and Resources Study. http://www.bpa.gov/power/pgp/whitebook/whitebook.shtml.

customers. In accordance with the MOA, BPA sets-aside or designates Network Resources for the purpose of serving its NT loads (Exhibit A identifies 24,662 MW). Also, in accordance with the MOA, BPA undesignates thirty-five percent of the aggregate nameplate capacity for the purpose of meeting grandfathered and statutory obligations. Therefore, BPA TS (Transmission Service) is obligated to secure firm transmission for the resulting 65% of Network Resources or 16,030 MW.

IX. Conclusion

The Coalition believes that BPA should adopt a 1 NCP methodology. Nonetheless, the Coalition urges BPA to re-evaluate its cost allocation recommendation and withhold further judgment until further discussions are held during the pre-transmission rate case workshops or separate workshops. The Coalition appreciates BPA's review of these comments and consideration of the recommendations contained herein, and the members of the Coalition look forward to collaborating with BPA and others on these matters.

Sincerely,

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On behalf of the

Point to Point Customers Coalition
Avista Corporation, and
Puget Sound Energy, Inc.

ATTACHMENT A

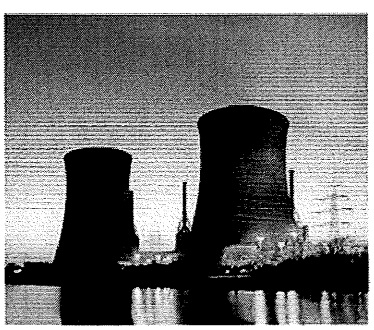
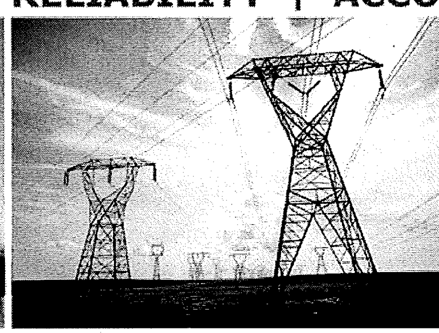
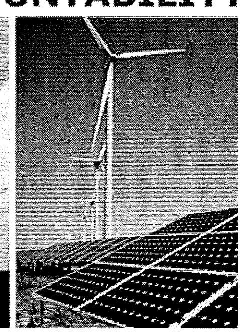
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Winter Reliability Assessment

2011/2012

RELIABILITY | ACCOUNTABILITY

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Assessment Areas

Based on recommendations from industry representatives as well as approval from the NERC Planning Committee, assessment boundaries were reconstructed beginning in 2011 to represent existing operating boundaries used in the planning process.[5] Prior to 2011, Regional Entity boundaries were used for NERC assessments; however, these borders do necessarily signify that planning and operations occur within a single Regional Entity. Therefore, assessment boundaries were enhanced using existing operational and planning boundaries versus traditional NERC Regional Entity boundaries (Figure A). Additional insights will be gained as planning and operations are aligned within each assessment area. Assessment boundary changes from 2010 to 2011 are outlined below (Table B).

Figure A: Assessment Areas Map

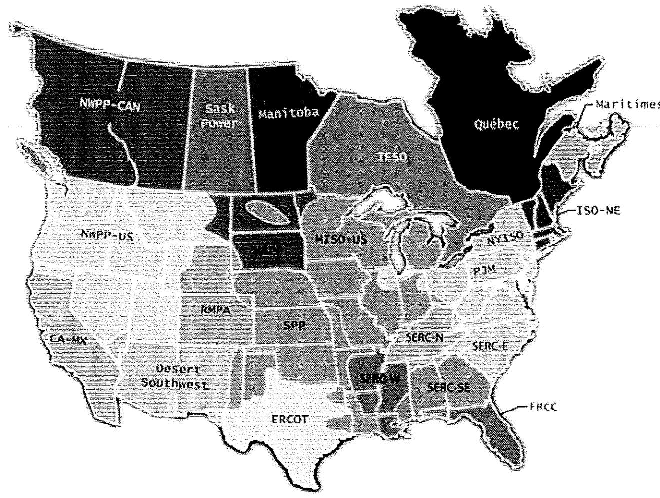


Table B: 2010 Assessment Areas Comparison to 2011

Assessment Areas		NERC Regional Entity	Description of Change
2010	2011		
TRE	ERCOT	TRE	Area name changed to reflect the operator
FRCC	FRCC	FRCC	No change
New England	ISO-NE	NPCC	Area name changed to reflect the operator
New York	NYISO	NPCC	Area name changed to reflect the operator
Maritimes	Maritimes	NPCC	No change
Ontario	IESO	NPCC	Area name changed to reflect the operator
Québec	Québec	NPCC	No change
MRO CAN	SaskPower, Manitoba	MRO	SaskPower and Manitoba now separate assessment areas
MRO US	MAPP	MRO	MAPP Planning Authority, removed MISO
—	MISO	MRO, RFC, SERC	MISO RTO
—	PJM	RFC, SERC	PJM RTO
Central	SERC-N	SERC	Removed PJM RTO members
Delta	SERC-W	SERC	Removed SPP RTO members
Gateway	—	—	Removed, part of the MISO RTO
Southeastern	SERC-SE	SERC	No change to boundary
VACAR	SERC-E	SERC	Removed PJM RTO members
SPP	SPP	SPP RE	SPP RTO and residual SPP RE members
CA-MX	CA-MX	WECC	No change
Desert SW	Southwest RSG	WECC	Cosmetic – Name Change Only
RMPA	Rocky Mountain Reserve Area	WECC	Cosmetic – Name Change Only
NWPP	NWPP	WECC	No change, Data is presented for both the US and Canada portions of NWPP

Enhancement to Reserve Margin Calculation

A significant change initiated in 2011 establishes a more consistent method to account for Demand Response in the Reserve Margin (RM) calculation. In previous reliability assessments, some Controllable Capacity Demand Response (CCDR) programs were used to reduce Total Internal Demand (Net Internal Demand), and some programs were included as a supply-side capacity resource. In prior years, the

[5] Reliability Assessment Procedure: Subregional Restructuring to support ISO/RTO Boundaries, December 2010. http://www.nerc.com/docs/pc/ras/Reliability%20Assessments%20-%20Subregional%20Restructuring.pdf

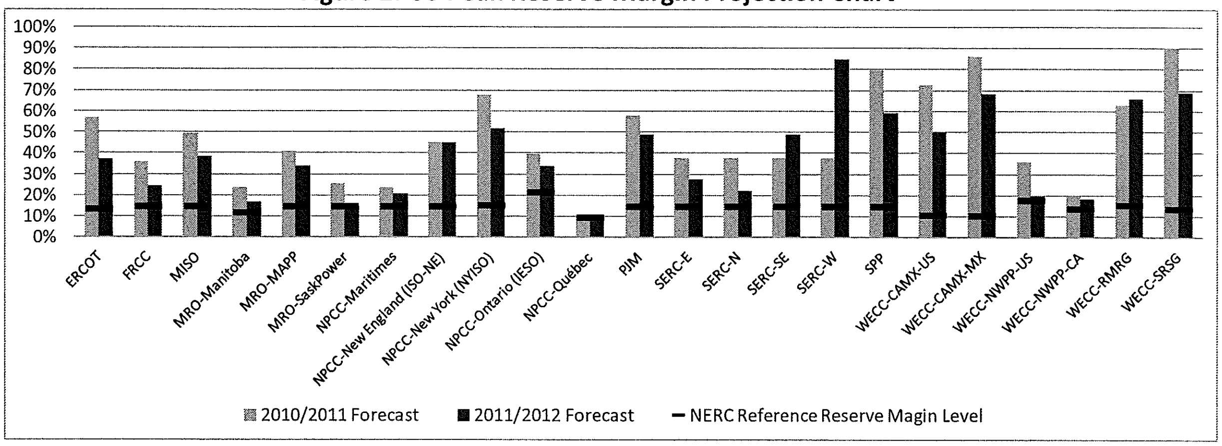
2011/2012 Winter Reliability Assessment

Resource Adequacy Assessment

All Regional Entities are projecting to have sufficient Reserve Margins[8] to ensure bulk power system reliability throughout the 2011/2012 winter season. Adequate Reserve Margins are essential for maintaining reliability by providing system operators with the flexibility needed to withstand unexpected generation or transmission outages and deviations from the demand forecast.

The winter peak Anticipated Planning Reserve Margin across North America (United States, Canada, and Mexico) for non-coincident peak demand[9] is expected to be 39.3%, which is 77 basis points (7.7 percentage points) lower than the 2010/2011 forecast.[10,11,12]

Figure 2: US Peak Reserve Margin Projection Chart[13]



A number of summer peaking regions within North America are reporting a lower Anticipated Planning Reserve Margin in comparison with 2010/2011, including ERCOT, FRCC, NPCC-New York, and PJM. Increases in Anticipated Planning Reserve Margins can be found in SERC-SE, SERC-W, and WECC-RMRG.

For winter peaking assessment areas[14], Anticipated Planning Reserve Margins are close to the NERC Reference Margin Level,[15] however these assessment areas continue to meet their reliability-based

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[8] In this report, "Reserve Margin" represents "Planning Reserve Margin". Reserve Margins for the upcoming winter are calculated by using projected on-peak capacity resources (generation, demand resources, and net transfers) and a 50/50 demand forecast, which represents a forecast value for an actual value having equal chance of either falling above or below the forecast value.

[9] The non-coincidental peak demand is higher than the peak demand at any single point in time (coincident peak), as it takes into account each assessment areas peak demand over the winter forecast.

[10] The North American bulk power system does not have the capability to transmit power across its entire expanse; therefore, a North American Reserve Margin is only a general indicator. It is not representative of resource adequacy within all Areas of North America.

[11] The 2010/2011 Reserve Margin was calculated using the same method used in 2011/2012. Approximation was used in developing the 2010/2011 Reserve Margin – error was +/- 0.2 percent

[12] See the *Demand, Resources, and Reserve Margins* section for the associated Reserve Margins by Country and Assessment Area. The tables in this section are the reference source for tables and figures in the NERC Reliability Assessment Section

[13] For this Figure, 2010/2011 Reserve Margins for the SERC-W, SERC-E, and SERC-N are based on the "old" SERC subregions of SERC-Delta, SERC-VACAR, and SERC-Central, respectively. WECC-SRSG and WECC-RMRG are based on the "old" WECC subregions of Desert-Southwest (DSW) and Rocky Mountain Power Area (RMPA), respectively.

ATTACHMENT B

RELIABILITY CRITERIA FOR SYSTEM PLANNING

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RELIABILITY CRITERIA FOR SYSTEM PLANNING

1. INTRODUCTION

1.1. Philosophy

The BPA transmission system is planned, designed, constructed, and operated to insure cost-effective reliability of service. Cost-effectiveness is viewed from the perspective of the electricity consumer. The system is planned to have sufficient strength or capacity to maintain continuity and quality of service to electrical loads during certain more common contingencies or system disturbances. For other less common contingencies, it is not economical to provide enough capacity to maintain full service, so interruption of service or some reduction of quality of service is allowed.

1.2. Description

The Reliability Criteria for System Planning set the performance requirements for planning the BPA system. The performance requirements are given in terms of the effects that are allowed on electrical loads and the transmission system as a result of various contingencies. The Criteria are deterministic, that is, the same generalized performance is specified for the same generalized types of contingencies and applied uniformly over the system. Application of the criteria is expected to provide overall system cost-effectiveness.

Criteria adopted by the Western Systems Coordinating Council (WSCC), "Reliability Criteria for System Design," set the limits of the effects that disturbances on one system can have on other systems. The BPA system is planned to satisfy both the BPA and WSCC criteria.

1.3. Application

The criteria set minimum performance requirements. They are intended to provide firm guidance but not absolute standards for planning. Application of the criteria must be tempered by the judgement of experienced planners and the circumstances that apply in each specific situation.

2. DEFINITIONS

2.1. The Transmission System

2.1.1. Intertie - A line or lines and related substations that provide an interconnection between the Northwest and another region.

2.1.2. Region - A portion of the WSCC system, such as the Northwest, that operates as an interchange area. Other examples are B.C. Hydro, W Kootenay, Montana, Idaho, LADWP, and PG & E. These WSCC interchange areas connect directly with the Northwest.

2.1.3. Main Grid - The transmission lines and related substations that carry bulk power within the Northwest. The main grid provides the primary connections among major load areas, large generating plants, major interties, and some intermediate load areas. The main grid includes all 500-kV and 345-kV lines, and those lower voltage lines that perform the main grid function, other than interties. Those portions of substations, including transformers, supporting the main grid lines are also included.

2.1.4. Secondary Grid - The transmission lines and related substations (other than the main, radial, and improved radial grids and interties) that connect the main grid, points of delivery, and points of interconnection.

2.1.5. Improved Radial Grid - Any substation on a transmission loop, and the lines in the loop, where only one of the sides of the loop serving the improved radial substation has sufficient line capacity to serve the entire normal peak load.

2.1.6. Radial Grid - A substation and the transmission line that provides the only connection between the substation and the rest of the transmission system. All substations along the radial line are included.

2.1.7. Point of Delivery - Point at which utility systems are connected with the primary purpose of one-way power delivery.

2.1.8. Point of Interconnection - Point at which utility systems are connected at which power can flow in either direction for power delivery (point of delivery), resource integration (wheeling), and system reliability improvement.

2.1.9. Major Load Area - A major population center in the Northwest with a large load and strong integrating transmission facilities, served directly from the main grid. Surrounding territory which is electrically integrated is included. These are Puget Sound, Greater Portland, Greater Spokane, and Willamette Valley.

2.1.10. Intermediate Load Area - An area in the Northwest having a substantial load (possibly a portion of a major load area) and multiple transmission facilities. Examples are Western Montana, the Minidoka area, Northern Idaho, the Tri-Cities area, the Olympic Penninsula, and the Bend area.

2.2. Remedial Actions

Remedial action schemes, also known as special protection systems or special stability controls, are planned controlled protective measures which are initiated following a transmission system disturbance to provide for acceptable system performance. Remedial actions, the individual protective measures that make up a remedial action scheme, are automatic noncontinuous supplementary controls that perform functions other than the isolation of electrical faults. Examples of remedial actions which may be used on the BPA system are:

2.2.1. Generator Dropping: Disconnection of certain selected generators to prevent system breakup.

2.2.2. Load Tripping: Disconnection of certain selected loads to prevent system breakup or voltage collapse.

2.2.3. Load Shedding: Reduction of load by means of underfrequency relays to prevent disconnection of frequency sensitive generators and minimize frequency decline, or undervoltage relays to prevent voltage collapse.

2.2.4. Dynamic Braking Resistor: A special resistive load applied to decelerate rapidly accelerating generators to prevent system breakup.

2.2.5. Reactive Switching: Application or removal of shunt or series capacitors, or shunt reactors, to prevent system breakup or voltage collapse.

2.2.6. DC Fast Ramping: A rapid step power change in DC schedule for designated outages to assure system stability and to maintain AC system loadings within emergency limits.

2.2.7. Generator Fast Valving: Rapidly controlled partial closure of turbine valves on a thermal generator to improve system stability for designated outages by reducing power output. This may be in the form of temporary or sustained fast valving.

2.2.8. Transient Excitation Boosting: Boosting excitation of generators by insertion of a discontinuous signal (decaying pulse) into the excitation system to improve system stability.

2.2.9. Islanding: Disconnection of a portion of the system from the rest of the interconnected grid to prevent widespread cascading outages. All or part of the disconnected portion may be blacked out.

2.3. Interregional Separation: Separation of a region from the rest of the interconnected system.

2.4. Area Separation: Disconnection of a load area by protective relay action. All or part of the disconnected area may be blacked out.

2.5. Contingency: Automatic disconnection (momentary or permanent) or emergency manual disconnection of a transmission facility or generator.

2.6. Cascading - The uncontrolled successive loss of system elements in which the loss of each successive element is contingent upon prior losses of elements.

3. ASSUMPTIONS

3.1. Loads

3.1.1. Normal Cold - The winter peak load level expected at annual minimum temperatures that have a 50% probability of occurrence.

3.1.2. Intermediate Cold - The winter peak load level expected at annual minimum temperatures that have a 20% probability of occurrence.

3.1.3. Abnormal Cold - The winter peak load level expected at annual minimum temperatures that have a 5% probability of occurrence.

3.1.4. Normal Summer - The summer peak load level expected at annual maximum temperatures that have a 50% probability of occurrence.

3.1.5. Normal Light - The average yearly minimum off-peak load level.

3.2. Generation

3.2.1. Basic Assumptions

Coordinated hydrothermal operation will be assumed. A historical water year is selected as the basis for the resource forecast to satisfy the demand and energy requirements with no surplus energy for the period of the planning study. The requirement will include scheduled interregional interchanges.

3.2.2. Variations

Both wet year and critical year generation patterns shall be evaluated to test the system under conditions of maximum regional export and import schedules. Other plausible variations in generation patterns that produce stresses in the transmission system shall also be examined.

3.3. Equipment Ratings

3.3.1. Lines

3.3.1.1. Lines will not be loaded so as to exceed limits established by ANSI Standards or standards otherwise established by BPA, in accordance with the Reliability Criteria and Standards section, "Transmission Lines I-E."

3.3.1.2. Line ratings will be consistent with the following ambient temperatures:

Load Period	East of Cascades	West of Cascades	Coast and Puget Sound
Normal Cold	-15°C	-5°C	-5°C
Intermediate Cold	-22°C	-10°C	-10°C
Abnormal Cold	-30°C	-15°C	-15°C
Normal Summer	40°C	40°C	35°C

The assumed ambient temperatures are about the same as the temperatures assumed to establish load levels for the warmest of the load points located in the zones indicated.

3.3.1.3. Thermal Rating - Continuous loading that causes rated conductor temperature at assumed ambient conditions.

3.3.2. Transformers

3.3.2.1. Ambient temperatures assumed for transformer ratings used in planning studies will be consistent with those assumed for the load level being studied. Site specific temperature data will be used when available.

3.3.2.2. Thermal Rating - Continuous loading, at the assumed ambient temperature, that causes a maximum hot spot temperature of 110°C for banks with thermally upgraded paper and 100°C for all others.

3.3.2.3. Emergency Rating - Continuous loading above the thermal rating, at the assumed ambient temperature, that causes an additional loss of life of 0.5% per week without causing maximum hot spot temperature to exceed 140°C or loading to exceed 150% of maximum nameplate rating.

3.3.2.4. Overexcitation of transformer windings is not to exceed 5% on the secondary or 10% on the primary at rated loading. Overexcitation is defined as:

$$\frac{\text{(applied voltage)} - \text{(nominal tap voltage)}}{\text{(nominal tap voltage)}} \times 100\ \%$$

3.3.3. Switchgear and Terminal Equipment

Switchgear and other terminal equipment will not be loaded beyond the limits established by ANSI Standards or standards otherwise established by BPA, in accordance with the Reliability Criteria and Standards section, "Substations I-F".

3.4. Bus Arrangements

3.4.1. Basic Objectives

Circuit elements such as lines, transformers, generators, capacitors, and reactors are connected to the transmission grid through circuit breakers or other types of switches to allow isolation of circuit elements (for maintenance or to clear faults) or to reconfigure the network. These elements may be connected through more than one breaker in parallel to provide redundant connections or through breakers in series to assure isolation of a faulted element if a breaker malfunctions. Connections may be provided to allow substitution of a spare breaker for a breaker that must be taken out of service. The pattern of connections and number of breakers desired for a particular application are achieved through the substation bus arrangement.

A variety of reasonably practical bus arrangements of varying costs are possible for any substation. Having met the basic performance requirements of the Reliability Criteria, the selection of a bus arrangement should provide an optimum balance of system performance, reliability, ease and safety of operation and maintenance, simplicity, adaptability, and cost. The various arrangements will each provide different advantages and tradeoffs.

3.4.2. Layout Guidelines

BPA uses single bus, main and transfer(auxiliary) bus, ring bus, modified ring bus (ring with a cross connection), and breaker-and-a-half bus arrangements. These are the preferred bus arrangements. It is recognized that other arrangements may be appropriate for special applications. Use of other arrangements shall be justified on a case-by-case basis. Guidance on development of bus arrangements follows:

3.4.2.1. Substations with main and transfer buses shall have switching or other provisions for sectionalizing to meet the performance requirements of Section 4 and facilitate maintenance or repair of the bus section without removing the entire bus from service. Circuit breakers are generally used on main buses. Disconnects or removable links are generally used on transfer buses. Power sources, when available, should feed into each section of the bus. Load shall be distributed among the bus sections. Potential transformers shall be installed on each bus section.

A bus tie breaker shall be installed at stations with main and transfer buses where a circuit breaker cannot be removed from service for maintenance when the system is normal (no outages) without loss of load or undue degradation of network reliability, or where adequate relay protection cannot be provided.

3.4.2.2. Early stages of breaker-and-a-half arrangement include ring and modified ring. The ring is used for three, four or five terminations. The modified ring is not used for more than eight terminations. A modified ring is an incomplete breaker-and-a-half. It has breakers in three bays. It shall not be necessary to open more than three breakers for normal clearing of a single termination.

The transition from ring to modified ring to breaker-and-a-half is not defined rigidly. Special reliability considerations such as line crossovers and similarity of critical circuits shall be considered. Incoming and outgoing lines shall be interlaced on the ring and modified ring.

Breaker-and-a-half stations should not have two incoming or outgoing lines in the same bay unless there is a mismatch in the number of incoming and outgoing lines or it can be shown that two similar lines in a bay are not detrimental to reliability.

3.4.2.3. With ring, modified ring, or breaker-and-a-half schemes, line disconnects should be installed in situations where opening the ring because of a line outage jeopardizes service to a major or intermediate load area or limits sources of generation.

4. SYSTEM TESTS/PERFORMANCE REQUIREMENTS

4.1. Steady-state Voltage Requirements

4.1.1. Voltage Limits for System Planning. 4/

Nominal Voltage 1/ kV	Maximum Voltage 1/ kV	Minimum Voltage 2/ kV
12.5	13.1	11.9
13.8	14.5	13.1
24.9	26.1	23.7
34.5	36.2	32.8
46	48.3	43.7
69	72.5	65.6
115	121	109
138	145	131
161	169	153
230	242	218
345	362	--- 3/
500	550	500

1/ ANSI C84.1-1970
2/ Minimum BPA Planning Voltages
3/ Not Applicable in the BPA System
4/ For any nominal voltage not listed, the maximum and minimum voltages are +5% and -5% of nominal, respectively.

4.1.2. With normal light loads and average or better hydro conditions, it will not be necessary to switch lines out of service to keep voltages from exceeding maximum levels.

4.1.3. With normal light loads and critical hydro conditions or under other conditions that produce minimum system loadings, it shall be permissible to remove a line or lines from service to keep voltages from exceeding maximum levels. The reduced system shall satisfy all other performance requirements of Section 4.

4.1.4. Voltage swings caused by shunt capacitor or reactor switching shall not exceed 3 percent on any bus with all lines in service. Swings of up to 5 percent may be allowed where sufficiently small size capacitor blocks are not available in standard groups.

Such swings shall not exceed 8 percent on any bus with any line or transformer out of service. Swings of up to 10 percent may be allowed on customer service buses on an individual basis where investigation indicates that it would be acceptable to the customer and where sufficiently small size capacitor blocks are not available in standard groups.

4.1.5. Relaying of capacitors due to blown fuses shall not cause voltage to drop below the minimum voltage of Section 4.1.1. with all lines in service.

4.1.6. Capacitors or reactors should be added to hold voltage schedules -- if schedules cannot be held on the actual system for normal peak or light load conditions with all lines in service, and this creates a significant operating problem.

To meet the steady-state voltage requirements all Northwest regulating equipment, including generators, must be operated within limits. An allowance, developed from operating records (generators, capacitors, or reactors) shall be made for that equipment which is unavailable because of scheduled or forced outages. Coordinated operation of the Northwest Power Pool reactive and voltage control facilities shall be assumed.

4.2. Voltage Stability

Under outage conditions where voltage collapse is a potential problem, sufficient reactive margin should be provided to ensure that the collapse point is not too close to the normal operating point of the system.

4.3. Transient Stability

4.3.1. Remedial Actions

Remedial actions other than those involving load dropping may be used for any contingencies to maintain stability. Remedial actions involving load tripping or shedding may be used if the requirements for serving load, as specified in the Disturbance-Performance Tables, are met.

4.3.2. Faults - Stability will be maintained for the following tests:

4.3.2.1. Single Contingencies

A three-phase permanent fault with no reclosure should be assumed at the line terminals of the power circuit breaker. Three-phase faults and faults at the station are relatively rare and a severe test of the system but are used because of the simplicity of network representation. If performance is marginal under this test, stability should be checked for a three-phase fault one mile from the bus (normally the end of the ground wire).

Stability should also be tested for a single-phase fault at the line terminal of the power circuit breaker, with unsuccessful reclosure.

A single-phase line fault with successful reclosure, with another line out of service prior to the fault, is considered a single contingency, and load service requirements of the performance tables for a single line outage must be met.

4.3.2.2. Multiple Contingencies

For simultaneous outages, a single-phase fault should be assumed on the same phase of each involved line at the line terminal of the power circuit breaker, with unsuccessful reclosure.

For non-simultaneous outages, with either a line or a breaker out of service prior to a disturbance, a single-phase fault should be assumed at the line terminal of the power circuit breaker, with unsuccessful reclosure

Stuck breakers and bus outages should be studied as permanent single-phase faults at the breaker or bus.

4.3.2.3. Clearing times should be actual maximum times without added margin.

4.3.3. Load Models

In cases where specific load characteristics are not known, loads in stability studies should be represented as P = constant current and Q = constant impedance. Otherwise known load characteristics should be used.

4.3.4. Generation

Generation should be represented as operated, with governor droop or blocking as appropriate. PSS should be assumed in service per WSCC guidelines or as otherwise operated. Generator braking due to DC offset should be neglected.

4.3.5. Voltage Swings

4.3.5.1. Following fault clearing, voltage on load buses may not swing below 0.70 times the pre-fault voltage or remain below 0.80 times the pre-fault voltage for more than 0.7 seconds.

4.3.5.2. Maximum acceptable voltage swing on the 500-kV system is 650-kV on 2.0 per unit design lines and 600-kV on 1.7 per unit design.

4.3.6. Damping

Acceptable system performance requires positive damping of all appropriate machine quantities, bus voltage, frequency, and tie line power.

4.4. Disturbance-Performance Tables

The Disturbance-Performance Tables on the following pages specify the transmission system performance required for the contingencies that are considered generally credible events that merit consideration in planning the BPA system. Performance levels are given for the main grid, secondary grid, improved radial grids, and radial grids. The accompanying Performance Levels Table specifies the requirements to be met for each performance level.

The following rules are to be observed in applying the tables:

4.4.1. Contingencies are permanent outages.

4.4.2. For a transformer outage or multiple contingencies involving lines or transformers; sectionalizing the system, reconnecting loads, or adjusting generation to control overloads on transformers or lines are permissible. No adjustments are allowed for single line outages. Transformers may not be loaded above emergency limits (except for transient power swings) even to allow time for system adjustments. Minimum voltage requirements apply after system adjustments are made.

All multiple contingencies are considered to be independent events except for lines in the same corridor, pass, or right-of-way or that connect to a common bus or breaker. Independent contingencies are considered to be non-simultaneous, and 1/2 hour should be assumed to be available between contingencies for system adjustments. Dependent contingencies should be considered to occur simultaneously.

4.4.3. System transient and voltage stability must be maintained for all performance levels.

4.4.4. The tables are set up to apply to winter peak load periods. For summer peak load periods, normal summer load must be served for Performance Levels A through D.

Some portions of the system may be under maximum stress during off-peak load conditions. This may occur for certain off-peak generation patterns, or during warmer spring or autumn periods (when equipment ratings are reduced) if peak loads do not vary much from normal winter levels. For such periods, all load must be served for Performance Levels A through D.

4.4.5. The performance tables for the secondary grid are not applicable for multiple contingencies that separate a loop system from the rest of the grid. It is accepted that all load will be curtailed when a loop system is isolated.

MAIN GRID

DISTURBANCE-PERFORMANCE TABLE

CONTINGENCY (ELEMENTS LOST) (independent unless otherwise noted)	PERFORMANCE LEVEL REQUIRED
none (system normal)	A
one generator	B
one transformer, or two generators, or one line	C
one generator + one transformer, or one line + one generator, or stuck breaker or bus, or two lines (common row, bus, or PCB) *	D
two transformers, or one line + one transformer	E
two lines, or three or more lines in a pass or corridor *	G

* Dependent contingencies

PERFORMANCE LEVELS

REQUIREMENTS	A	B	D	E	G
Serve abnormal cold load	X	X			
Serve normal cold load			X		
Load tripping allowed				X	X
Area separation and load loss allowed					X
Some intertie opening allowed (but no interregional separation)					X
Maintain nominal or better voltage (525-kV or better on the 500-kV system)	X				
Maintain minimum or better voltage		X	X	X	X
No line or transformer loading above thermal rating	X				
No transformer loading above emergency rating		X	X	X	X
No line above rated conductor temperature		X	X	X	X

SECONDARY GRID

DISTURBANCE-PERFORMANCE TABLE

CONTINGENCY (ELEMENTS LOST) (independent unless otherwise noted)	PERFORMANCE LEVEL REQUIRED
none (system normal)	A
one generator	B
one transformer, or two generators, or one line	D, or C-(for larger 230-kV systems)
one generator + one transformer, or one line + one generator, or stuck breaker or bus, or two lines (common row, bus, or PCB) *	E
two transformers, or one line + one transformer	E
two lines, or three or more lines in a pass or corridor *	F

*Dependent contingencies

PERFORMANCE LEVELS

REQUIREMENTS	A	B	C	D	E	F
Serve abnormal cold load	X	X				
Serve intermediate cold load			X			
Serve normal cold				X		
Load tripping allowed					X	X
Area separation and load loss allowed						X
Maintain nominal or better voltage (525-kV or better on the 500-kV system)	X					
Maintain minimum or better voltage		X	X	X	X	X
No line or transformer loading above thermal rating	X					
No transformer loading above emergency rating		X	X	X	X	X
No line above rated conductor temperature		X	X	X	X	X

IMPROVED RADIAL GRID

DISTURBANCE-PERFORMANCE TABLE

CONTINGENCY (ELEMENTS LOST)	PERFORMANCE LEVEL REQUIRED
none (system normal)	A
weaker line	D
stronger line	IR1

RADIAL GRID

DISTURBANCE-PERFORMANCE TABLE

CONTINGENCY (ELEMENTS LOST)	PERFORMANCE LEVEL REQUIRED
none (system normal)	A
the radial line	**

** The radial system is out of service. All radial load is curtailed.

PERFORMANCE LEVELS

REQUIREMENTS	PERFORMANCE LEVEL A	D	IR1
Serve abnormal cold load	X		
Serve normal cold load		X	
Serve 80% of normal cold load			X
Maintain nominal or better voltage	X		
Maintain minimum or better voltage		X	X
No line or transformer loading above thermal rating	X		
No transformer loading above emergency rating		X	X
No line above rated conductor temperature		X	X

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