Available Transfer Capability Implementation Document (MOD-001-1a)

Bonneville Power Administration
Transmission Services

Effective Date: February 13, 2013

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I. Purpose

This BPA Available Transfer Capability Implementation Document (ATCID) addresses all of the requirements of North American Electric Reliability Corporation (NERC) Reliability Standard MOD-001-1 Available Transmission System Capability. This ATCID is specifically required by MOD-001-1, R3 and its subrequirements. This ATCID only applies to ATC or Available Flowgate Capability (AFC) calculations through month 13.

II. Definitions

All capitalized terms used in this ATCID are either contained in NERC's Glossary of Terms used in NERC Reliability Standards or, if not in NERC's glossary, are defined in this ATCID.

Defined terms specific to BPA include:

- **Federal Columbia River Power System (FCRPS):** The Transmission System constructed and operated by BPA and the 31 federally-constructed hydroelectric dams[1] on the Columbia and Snake Rivers, and the Columbia Generating Station nuclear plant. Each entity is separately managed and financed, but the facilities are operated as an integrated power System.
- **Federal Columbia River Transmission System (FCRTS):** The FCRTS is comprised of BPA's main grid network Facilities (Network), Interconnections with other Transmission Systems (External Interconnections[2]), Interties,[3] delivery Facilities, subgrid Facilities, and generation Interconnection Facilities within the Pacific Northwest region and with western Canada and California.
- **Long-Term Reservation:** a confirmed reservation that has duration greater than or equal to 365 days or any confirmed firm Network Integration Transmission Service reservation.
- **Short-Term Reservation:** a confirmed reservation that has duration less than 365 days, excluding confirmed firm Network Integration Transmission Service reservations.

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[1] Albeni Falls, Anderson Ranch, Big Cliff, Black Canyon, Boise River Diversion, Bonneville, Chandler, Chief Joseph, Cougar, Detroit, Dexter, Dworshak, Foster, Grand Coulee, Green Peter, Green Springs, Hills Creek, Hungry Horse, Ice Harbor, John Day, Libby, Little Goose, Lookout Point, Lost Creek, Lower Granite, Lower Monumental, McNary, Minidoka, Palisades, Roza and The Dalles

[2] Northern Intertie, Reno-Alturas Transmission System, West of Hatwai, West of Garrison and LaGrande paths.

[3] California-Oregon AC Intertie, Pacific DC Intertie, and Montana Intertie.

III. Overview

BPA owns and provides Transmission Service over the FCRTS (see p. 3 for definition). MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-02 variously apply to the Transmission Operator (TOP) and Transmission Service Provider (TSP). BPA is registered with NERC as a TOP and TSP, among other registrations. As such, three organizations within BPA's Transmission Services organization are responsible for specific portions of the above-referenced MOD Standards. Those organizations are System Operations, Planning and Asset Management, and Transmission Marketing and Sales. Various requirements within the above-referenced MOD Standards require the TOP to share study reports and other information with the TSP and vice versa. Information is shared electronically between the appropriate BPA organizations.

Requirement 1 in NERC's Standard MOD-001-1 requires all TOPs to select one (or more) of three methodologies for calculating ATC or AFC for each ATC Path for each time period (MOD-028-1, MOD-029-1 or MOD-030-2).

Methodologies Selected

MOD-029-1

BPA has elected to use the Rated System Path Methodology described in NERC Standard MOD-029-1 as its methodology to determine ATC for its Interties, External Interconnections and some Paths internal to BPA's Network. The description of how BPA implements this methodology is included in Section VII of this ATCID. (MOD-001 R1)

MOD-030-2

BPA has elected to use the Flowgate Methodology described in NERC Standard MOD-030-02 as its methodology to determine AFC for its Network Flowgates. The description of how BPA implements this methodology can be found in Section VIII of this ATCID. (MOD-001 R1)

MOD-008-1

BPA maintains Transmission Reliability Margin (TRM) as described in NERC Standard MOD-008-1 in its ATC calculation for its Northern Intertie Path. The description of how BPA implements TRM can be found in BPA's TRM Implementation Document (TRMID) found on BPA's website http://transmission.bpa.gov/business/atc_methodology/. BPA does not maintain TRM in its ATC and AFC calculations for any other ATC Paths or Flowgates.

Methodologies Not Selected/Not Applicable to BPA

MOD-028-1

BPA has elected not to use the Area Interchange Methodology described in NERC Standard MOD-028-1 as its methodology to determine ATC for any of its ATC Paths. Therefore MOD-028-1 is not applicable to BPA.

MOD-004-1

BPA does not maintain a Capacity Benefit Margin (CBM) nor does it use CBM in the assessment of either ATC or AFC in any time horizon. Therefore, the requirements set forth in NERC Standard MOD-004-1 are not pertinent to BPA.

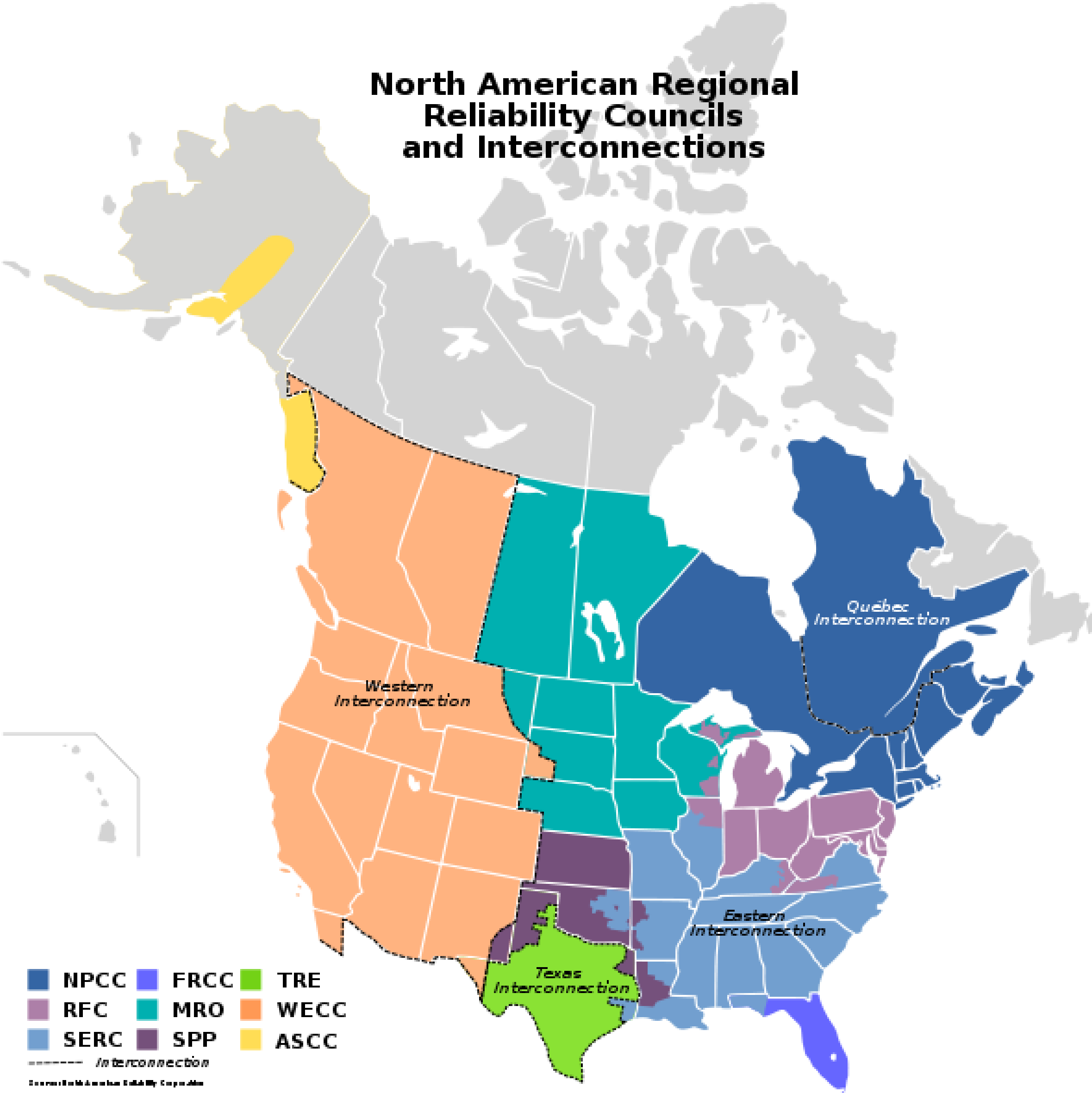
BPA's Use of Western Electricity Coordinating Council Base Cases

The Western Electricity Coordinating Council (WECC) is the NERC-certified Regional Entity responsible for coordinating and promoting Bulk Electric System reliability in the Western Interconnection.

WECC's operating area includes 37 Balancing Authorities (BAs) and 302 member organizations (including large Transmission Owners, small Transmission Owners, Transmission-dependent energy service providers and end users), operating as the Western Interconnection. The Western Interconnection covers all or parts of the 14 western United States, the Canadian provinces of British Columbia and Alberta, and a portion of Baja California Norte, Mexico. The 14 states are parts of Montana, Nebraska, New Mexico, South Dakota, Texas, and Wyoming and all of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, and Washington.

The following map shows all of the NERC regional entities including WECC's operating area, the Western Interconnection.

Figure 1



WECC's Technical Studies Subcommittee (TSS) and its workgroups, under the direction of the WECC Planning Coordination Committee, are responsible for performing studies and maintaining data files, among other responsibilities. The TSS is responsible for preparing and maintaining base case data. WECC's members, including BPA, submit operating and planning data, including Load and generation forecasts, as well as generation and Transmission additions and retirements, to WECC's staff. WECC's staff then prepares the operating and planning power flow base cases on which BPA and its adjacent BAs rely for the power flow base cases that are the foundation of all Western Interconnection generation and Transmission planning and operating studies. The Transmission and power System data each WECC member is required to provide is detailed in the WECC Data Preparation Manual.

BPA uses these same WECC base cases as the starting point for all of the studies it does in support of its Total Transfer Capability (TTC), Total Flowgate Capability (TFC) and AFC calculations. There are five WECC base cases per year that are relevant to BPA studies: heavy winter operations, light winter operations, heavy spring operations, heavy summer operations, and light summer operations. BPA uses the WECC base cases that represent generation and Transmission for the spring, summer and winter periods to perform its TTC, TFC and AFC analyses for its Transmission System in the Northwest Region of the Western Interconnection, as defined in the WECC Data Preparation Manual.

ATC and AFC Calculations

ATC and AFC Calculation Periods

BPA calculates ATC and AFC values using the Rated System Path and Flowgate Methodologies for the following time periods: (MOD-001 R2)

- Hourly values for up to 168 hours. (MOD-001 R2.1)
- Daily values for day 3 through day 90. For days 3 to 7 (up to hour 168), the daily ATC and AFC value is the most limiting hourly ATC and AFC value for that day. (MOD-001 R2.2)
- Monthly values for month 2 through month 13. For months 2 and 3 (up to day 90), the monthly ATC and AFC value is the most limiting daily ATC and AFC value for that month. (MOD-001 R2.3)

Frequency of ATC and AFC Recalculation

BPA recalculates ATC and AFC on the following frequency, even if the calculated values identified in the ATC or AFC equation are unchanged: (MOD-001 R 8, MOD-030 R10).

- Hourly, at least once per hour (MOD-001 R 8.1, MOD-030 R10.1).
- Daily, at least once per day. (MOD-001 R8.2, MOD-030 R10.2).
- Monthly, at least once per day. (MOD-001 R8.3, MOD-030 R10.3).

BPA may recalculate ATC and AFC values more frequently due to changes in TTC or TFC, Power Transfer Distribution Factors (PTDFs), system issues or as deemed necessary.

Limiting Assumptions

The System Operating Limits (SOLs) BPA develops for its planning of operations are used in determining the TTC for ATC purposes, and the TFC for AFC purposes. Therefore when calculating TTC and TFC, BPA uses assumptions that are no more limiting than those used in its planning of operations for the corresponding time period, when such planning of operations has been performed for that time period. (MOD-001 R6)

When calculating ATC, BPA subtracts its Existing Transmission Commitments (ETC) from the TTC set from the SOL BPA develops for its planning of operations. No additional studies beyond those developed to determine SOLs used in calculating TTCs are performed to calculate ATC. Therefore there are no assumptions used to calculate ATC to compare to assumptions used in BPA’s planning of operations. (MOD-001 R7)

When calculating AFC, BPA uses the WECC base cases and modifies them to determine the firm Existing Transmission Commitments (ETC_{Fi}) component of the AFC calculations. The assumptions used in these ETC Cases include normal operating conditions System topology, a 1-in-2-year seasonal heavy Load forecast or seasonal light Load forecast depending on the flowgate being studied, and generation dispatches based on the firm Transmission rights associated with specific generators.

BPA also uses the WECC base cases to determine SOLs used to calculate TFCs. The assumptions used in these cases include either normal operating conditions System topology when no Transmission outages are being studied or Transmission outages if they are known at the time of the study, a 1-in-2-year seasonal heavy Load forecast or light Load forecast depending on the flowgate being studied, and conservative configurations of generating resources in and out of service, regardless of the Transmission rights associated with the specific generators.

BPA may use more recent information in its SOL calculations when the SOL studies are updated after the ETC Cases are performed. However, this is not considered a difference in assumptions. Consequently, when calculating AFC, BPA uses assumptions that are no more limiting than those used in the planning of operations for the corresponding time period studied, provided that such planning of operations studies have been performed for that time period. (MOD-001 R7)

IV. Allocation Processes

BPA uses the same methodology to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate as it uses to allocate transfer or Flowgate capability among multiple owners or users of an ATC Path or Flowgate. For Paths and Flowgates where ownership Agreements exist, the methodology is to allocate transfer or Flowgate capabilities according to contractual rights defined in individual Agreements among the various owners. These Agreements define the specific percentages of capacity or MW amounts of rights assigned to each owner for specific time periods. See Appendix A for a list of contracts and specified Paths and Flowgates with shared ownership. Agreements do not exist for three of BPA's Flowgates – South of Allston S>N, Columbia Injection N>S and Wanapum Injection N>S. For South of Allston S>N the same allocation methodology described in the SOA N>S Contract (#06TX-12300) is used. For Columbia Injection N>S and Wanapum Injection N>S, BPA determines its share of Total Flowgate Capability based on BPA's owned transmission lines that make up the flowgate when all lines are in service. During outage conditions, individual allocations exist for the loss of each transmission line in the flowgate. BPA determines its share of Existing Transmission Commitments for Columbia Injection N>S and Wanapum Injection N>S by modeling the full path of BPA's lines only.

At this time BPA does not allocate transfer or Flowgate capabilities between TSPs to address forward-looking congestion management and seams coordination. (MOD-001 R3.5)

V. Outages

Outages from all TSPs that are internal or adjacent to BPA's Balancing Authority Area (BAA) can be mapped to the WECC base cases (MOD-001 R3.6.3)

Outage Planning Timeline

BPA participates in a regional process which requires all participants to enter proposed significant outage plans for Facilities they own into the WECC Coordinated Outage System (COS) as soon as they are known, but at least 45 days prior to the month in which the proposed outage is to occur.

Emergency and urgent outages for safety or reliability reasons are always under the full jurisdiction and discretion of the System Operator. The responsibility for coordination of planned and scheduled outages falls upon each NWPP participant.

Information on the proposed outages is accessible from the Open Access Same Time Information Service (OASIS) of the Transmission Path Operator and to the public via WECC's COS. BPA creates monthly draft outage plans in spreadsheet format, showing all known outages compiled from WECC's COS. These draft outage plans (without capacity estimates) are then posted to the Outage Plans website (http://www.oatioasis.com/bpat/index.html) to allow for customer comment. The draft outage plans are continuously updated based on information posted to WECC's COS, until the 45-day outage planning process begins for the specific outage month.

At day 45 prior to the time of the outage month, the Path Operator/Coordinator compiles the initial outage plan for the month. The initial outage plan is posted, with the unstudied path capacity impact, by the close of business day 44, to the BPA website (http://www.oatioasis.com/bpat/index.html).

Following the monthly NWPP outage coordination meeting, hosted by BPA, concerns and comments are addressed, the revised unstudied Path capacity impact is determined for various outage combinations, and the coordinated outage plan is posted to the BPA website by the close of business day 36. The plan is then reviewed, adjusted and finalized, and the final outage plan is posted to the BPA website by the close of business day 30. At approximately day 15 prior to the outage week, the TSP posts studied TTC/TFC for planned outages to OASIS.

BPA has determined that at 10 to 16 days in the future, there is sufficient certainty around planned Transmission and generation outages to incorporate those outages into its Transfer and Flowgate Capability calculations. BPA has also determined that up to 16 days in the future, there is sufficient certainty around the energization of new Transmission additions to incorporate them into Transfer and Flowgate Capability calculations. Until up to 16 days in the future, Transmission additions for BPA's System are modeled as out of service in the WECC base cases and not included in Transfer and Flowgate Capability calculations.

Outages from adjacent TOPs that are not members of the NWPP are provided to BPA in the form of an official notification of a change to TTC due to a scheduled outage.

Outage Criteria for TTC and TFC Calculations

The duration of a given outage is not one of the criteria by which BPA determines which outages to incorporate in its daily and monthly TTC and TFC calculations. BPA considers generation and Transmission outages (discussed above) in TTC and TFC calculations through the following criteria:

Daily TTC and TFC Calculations

When updating the WECC base cases for daily TTC or TFC calculations for the 10 to 16-day outage study period, BPA assumes conservative configurations of generating and Transmission outages and other factors, regardless of the duration of a given outage or particular combination of outages.

Attachment B, "Significant Equipment List," in Significant Equipment Operating Bulletin No. 19 (OB 19) (Appendix B of this ATCID) lists the significant Transmission Facilities to which the NWPP outage planning process applies and which BPA considers in its daily TTC and TFC calculations. Specifically, the most conservative hourly TTC or TFC calculated for a given outage or combination of outages and other factors becomes the governing TTC or TFC for the daily calculation period.

BPA's initial daily TTC and TFC calculations may be updated as more current information on System conditions becomes available.

BPA does not generally consider generation or Transmission outages in daily TTC and TFC calculations beyond the 10- to 16-day planned outage study period because of the lack of certainty about planned outages scheduled for that period, unless the planned outage is scheduled to continue beyond the planned outage study period, or there is an outage that has been scheduled in BPA's outage system to begin beyond the 10- to 16-day period. (MOD-001 R3.6.1)

Monthly TTC and TFC Calculations

BPA does not generally consider generation or Transmission outages in monthly TTC and TFC calculations beyond the 10- to 16-day planned outage study period because of the lack of certainty about outages scheduled for the period beyond the 10- to 16-day planned outage study period, unless the completion of an outage that begins in the 10- to 16-day planned outage study period is scheduled into the monthly horizon, or there is an outage that has been scheduled in BPA's outage system to begin beyond the 10- to 16-day period. (MOD-001 R3.6.2)

VI. SOL Priorities Used to Set TTC and TFC

BPA calculates new SOLs when changes to System conditions will significantly impact those limits and uses those new SOLs to determine new TTC and TFC values. The following hierarchy of priorities categorizes the SOL values based on the time period being calculated and the reason for the change. This prioritization is then used to set the TTC or TFC for a given time period based on the concept that more recently-calculated SOL values are more accurate since they are based on updated System information:

- **Real-time limit (highest priority):** The "Real-time limit" priority governs when BPA updates SOLs during the Real-time horizon. A change to a SOL with the Real-time priority governs over all other priorities. For example, if BPA receives an update that a scheduled outage will be extended by two hours early in the Real-time day, BPA will update the SOL accordingly for the additional two hours and use that SOL to update the TTC or TFC. If more than one Real-time-limited SOL is calculated due to multiple real-time updates to SOLs, the most recent SOL calculated governs.

- **Scheduling limit:** The "scheduling limit" priority is used occasionally when the lowest SOL is not governing or an actual Scheduling limit has been imposed. For example, if there is a studied outage on the California-Oregon Intertie (COI) that results in a "studied" priority SOL of 3200 MW, but there is another outage combination in conjunction with the studied outage on the COI for the same time period that results in a Scheduling limit of 3400 MW, the Scheduling limit of 3400 MW governs during this time period and is used to set TTC. If there is more than one Scheduling limit, the lowest Scheduling limit governs until a Real-time limit SOL is submitted.
- **Pre-schedule forecast:** The "pre-schedule forecast" SOL priority is used for a Path or Flowgate where the SOL(s) is redefined for the pre-schedule period. For example, the SOL calculated for the Northern Intertie is derived using nomograms and is re-evaluated just prior to the pre-schedule day to incorporate updated data inputs. The pre-schedule forecast SOL governs over all the studied outages and is used to set the TTC and TFC value for a Path or Flowgate.
- **Studied:** The "studied" priority is used when there are outages where a study report has been issued, including those provided by other TOPs. For example, if a study report is issued for BPA's John Day-Grizzly #1 500kV Line outage, the study report provides SOLs for the COI and Pacific DC Intertie during the time period of the outage, which governs over any lower-priority SOLs.
- **Estimated known limit:** The "estimated known limit" priority is used to establish unstudied TTCs and TFCs or to define seasonal Path or Flowgate TTCs and TFCs that govern over "short-term seasonal" or "Path Rating" priorities.
- **Short-term seasonal:** The "short-term seasonal" priority is used for TTCs and TFCs issued for seasonal Path Ratings. As these Ratings may be higher at certain times during the year, the short-term seasonal priority governs over the Path Rating priority. For example, if the longer-term Path Rating for North of John Day is 7800 MW, but seasonally, this Rating increases to 8000 MW, the short-term seasonal Rating of 8000 MW governs and is used to set the TFC during the season to which it applies.
- **Path Rating:** The "Path Rating" priority is used to set base TTCs and TFCs using either the Rating of the Paths and Flowgates, SOLs studied using normal conditions, SOLs calculated for the planning horizon, or all of the above. The lowest value resulting from the above calculations within this grouping governs for the given time period and is used to set the TTC or TFC. For example, if under normal conditions the SOL for North of Hanford N>S is 4410 MW, but the SOL calculated for the planning horizon is 4100 MW, the lower SOL of 4100 MW governs and is used to set the TFC for this Flowgate.
- **Informational limit (lowest priority):** The "informational limit" is used while establishing the initial setup of Paths and Flowgates within the scheduling and reservation system. The informational limit is equal to the initial Path Rating of the Path or Flowgate.

VII. Rated System Path Methodology

This section describes in detail how BPA implements the Rated System Path methodology. It addresses all of the Requirements in Standard MOD-029-1.

BPA Paths

The following table shows the Paths for which BPA uses the Rated System Path methodology.

Table 1
Paths for which BPA uses Rated System Path Methodology

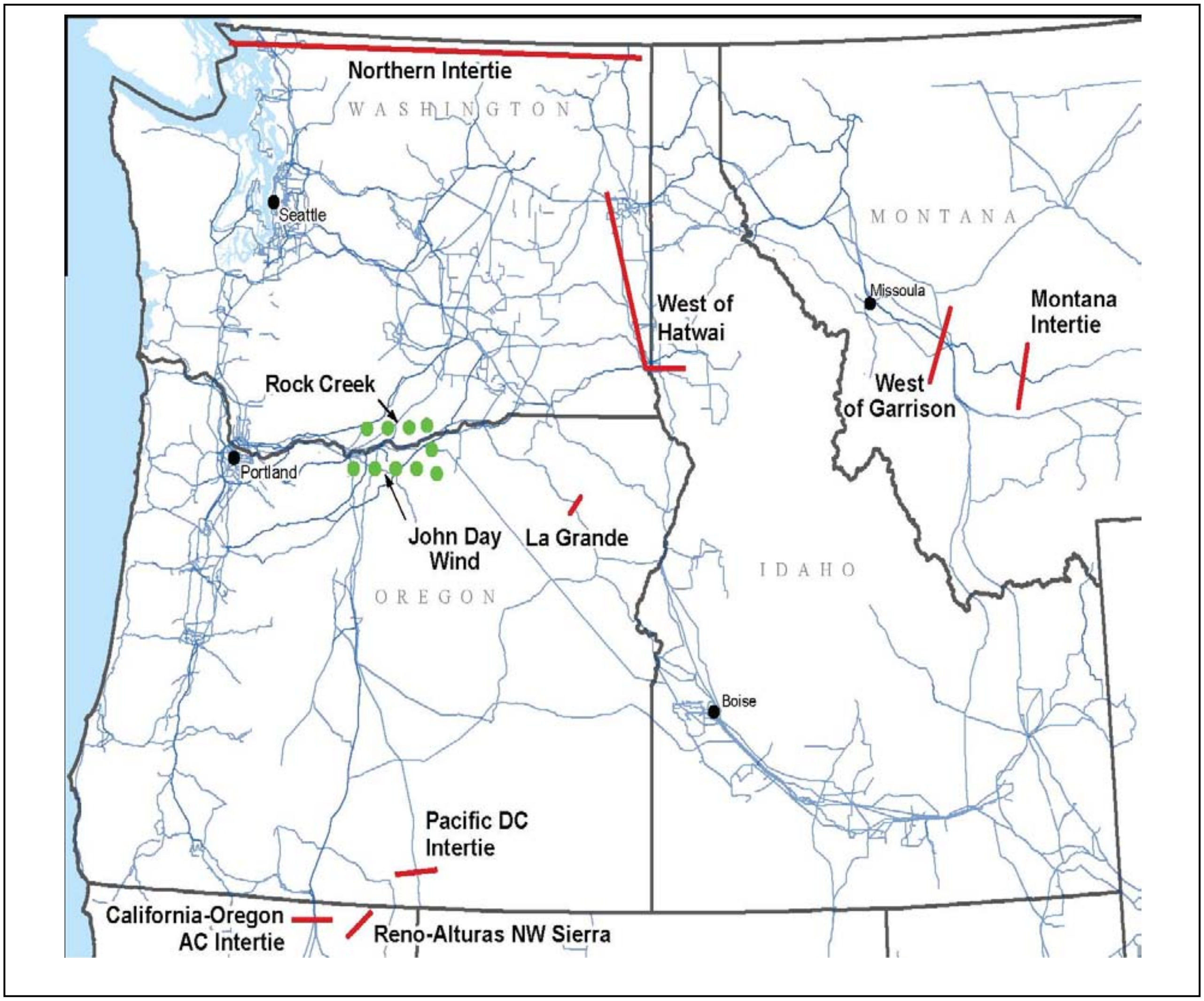
Path Name	Direction
Northern Intertie Total On Oasis: NI_TOTL_N>S	(N>S)
Northern Intertie Total On OASIS: NI_TOTL_S>N	(S>N)
West of Hatwai On OASIS: WOH_E>W	(E>W)
Montana-Northwest West of Garrison On OASIS: WOGARR_E>W	(E>W)
Montana-Northwest West of Garrison On OASIS: WOGARR_W>E	(W>E)
La Grande On OASIS: LAGR_W>E	(W>E)
La Grande On OASIS: LAGR_E>W	(E>W)
Montana Intertie On OASIS: MI_E>W	(E>W)
Reno-Alturas NW Sierra On OASIS: RATS_N>S	(N>S)
Reno-Alturas NW Sierra On OASIS: RATS_S>N	(S>N)
California-Oregon AC Intertie (COI) On OASIS: AC_N>S	(N>S)
California-Oregon AC Intertie (COI) On OASIS: AC_S>N	(S>N)

Path Name	Direction
Pacific DC Intertie On OASIS: DC_S>N	(S>N)
Pacific DC Intertie On OASIS: DC_N>S	(N>S)
Rock Creek On OASIS: ROCKCK_GEN	Gen
John Day Wind On OASIS: JDWIND_GEN	Gen

The following map shows the general geographic locations of the Paths listed in Table 1, above.

Figure 2

BPA Paths Map



Calculating Total Transfer Capability (TTC)

Data and Assumptions

When calculating TTC for its ATC Paths, BPA uses WECC base cases that utilize data and assumptions consistent with the time period being studied. (MOD-029 R1.1) In addition to BPA's TOP area, these WECC base cases model the entire Western Interconnection. Hence, the WECC base cases include all TOP areas contiguous to BPA's TOP area. (MOD-029 R1.1.1.2) There are no other TOP areas that are linked to BPA's TOP area by joint operating Agreement. (MOD-029 R1.1.1.3)

TOP areas contiguous with BPA's TOP area include (MOD-029 R1.1.1.2):

- Avista Corporation (AVA)
- BC Hydro (BCH)
- California Independent System Operator (CAISO)
- City of Tacoma, Department of Public Utilities, Light Division
- Eugene Water and Electric Board (EWEB)
- Idaho Power Company (IPCO)
- Los Angeles Department of Water and Power (LADWP)
- NorthWestern Energy (NWMT)
- PacifiCorp (PAC)
- Pend Oreille County Public Utility District No. 1
- Portland General Electric (PGE)
- Public Utility District No. 1 of Chelan County
- Public Utility District No. 1 of Clark County
- Public Utility District No. 1 of Snohomish County
- Public Utility District No. 2 of Grant County, Washington
- PUD No. 1 of Douglas County
- Puget Sound Energy, Inc. (PSEI)
- Seattle City Light (SCL)
- Sierra Pacific Power Company. (SPPC)

BPA uses the following data and assumptions in the WECC base cases when calculating TTCs for its ATC Paths:

BPA models all existing System Elements in their normal operating condition for the assumed initial conditions, up to the time horizon in which BPA begins modeling outages (see Section V, "Outages," beginning on p. 8). Most System Elements normally operate as in service; however, some System Elements normally operate in an open position. (MOD-029 R1.1.2)

The WECC base cases include generators that meet the guidelines set out in the WECC Data Preparation Manual. (MOD-029 R1.1.3)

Although BPA does not own phase shifters on its Transmission System, there are some phase shifters that are included in the WECC base cases at the boundaries of the BPA System. BPA models those phase shifters in non-regulating mode during outage studies and normal operating conditions studies, for which purposes BPA assumes that the tap changes are fixed. Changing the angle of a phase shifter is a manual action, so non-regulating mode is assumed for this condition. In outage studies, BPA only models automatic actions. The only exception is the Nelway phase shifter, which BPA models in regulating mode to develop the nomogram for the Northern Intertie. (MOD-029 R1.1.4)

BPA uses the seasonal Load forecasts contained in the WECC base cases for each BA. BPA engineers may run variations on the WECC base cases as needed to model near-term conditions. (MOD-029 R1.1.5)

Generation and Transmission Facility additions and retirements within the WECC footprint are included in the WECC seasonal operating base cases for the season in which they are energized/de-energized, respectively. BPA engineers modify the WECC base cases to reflect the actual dates of energization/de-energization. (MOD-029 R1.1.6, R1.1.7)

The WECC base cases include Facility Ratings as provided to WECC by the Transmission Owners and Generator Owners. (MOD-029 R1.2)

If Facility changes are made by BPA or another entity, then the base cases will not reflect these changes until the seasonal operating study reflecting these changes is completed by BPA and any required approval is obtained. (MOD-029 R1.1, R1.2)

The approved seasonal operating base cases that include the Facility changes will not be used until 0 to 16 days prior to the energization or implementation of the Facility change. (MOD-029 R1.1, R1.2)

For periods beyond two weeks, the WECC base cases will be updated as necessary to perform seasonal studies for the current or upcoming season in accordance with the current BPA study processes. For the seasons or time periods in which the seasonal studies have not been completed, the last year's seasonal study results will be used for setting the TTC for the relevant Path. BPA uses the minimum SOL from the relevant seasonal studies to set the TTC of the Path for periods beyond two weeks. For periods within the next two weeks, when there are no studied outages, BPA uses the maximum SOL from the relevant seasonal studies to set the TTC of the Path. (MOD-029 R1.1, R1.2, MOD-029 R2.1)

BPA models Special Protection Systems (BPA uses the term Remedial Action Schemes or RAS) that currently exist or are projected for implementation within the studied time horizon. See Table 1 beginning on p. 12 for a list of locations where BPA has RAS, and the ATC Paths impacted by those RAS. (MOD-029 R1.1.8)

The WECC base cases include all series compensation for each line at the expected operating level. BPA has Transmission lines with series compensation. (MOD-029 R1.1.9)

BPA uses no other modeling requirements for calculating TTC in addition to those specified in this document. (MOD-029 R1.1.10)

Process to Determine TTC

BPA adjusts generation and Load levels within the WECC power-flow base cases to determine the TTC that can be simulated for each of its ATC Paths, while at the same time satisfying all planning criteria contingencies, as follows:

When modeling normal conditions, BPA models all Transmission Elements in BPA's BAA and adjacent BAAs at or below 100 percent of their continuous Rating. (MOD-029 R2.1.1)

When modeling contingencies within BPA's BAA, BPA sets TTCs within all WECC performance criteria in WECC's TPL-(001 thru 004)-WECC-1-CR-System Performance Criteria document, including transient, dynamic and voltage Stability, with no Transmission Element within BPA's BAA modeled above its Emergency Rating. Refer to Appendix C of this ATCID, BPA Technical Operations System Operating Limits Methodology for the Operations Horizon (SOL Methodology) for a detailed description of how BPA determines SOLs used to set TTCs. (MOD-029 R2.1.2)

By meeting the above criteria, uncontrolled separation should not occur. (MOD-029 R2.1.3)

BPA can simulate a reliability-based flow in the direction counter to prevailing flows on all of its ATC Paths. Therefore BPA calculates reliability-based TTCs for all of its ATC Paths. (MOD-029 R2.2)

The Montana Intertie Path is limited by the Colstrip Project contract. NorthWestern Energy is the Transmission Operator and sets the TTC for this ATC Path. (MOD-029 R2.3)

For ATC Paths where TTC varies due to simultaneous interaction with one or more other Paths, BPA develops a nomogram, represented either by an equation or its graphical representation, describing the interaction of the Paths and the resulting TTC under specified conditions. BPA then calculates a value, based on that nomogram and forecasted System conditions for the time period studied, to develop its TTC values for the affected ATC Paths. The ATC Paths for which BPA expresses TTC by nomogram are the Pacific DC Intertie and the California-Oregon Intertie. (MOD-029 R2.4)

BPA or the adjacent Path TOP identifies when the new or increased TTC for an ATC Path being studied by BPA or the adjacent Path TOP has an adverse impact on the TTC value of another existing Path by modeling the flow on the Path being studied at its proposed new TTC level, while simultaneously modeling the flow on the existing Path at its TTC level. In doing so, BPA or the adjacent Path TOP honors the reliability criteria described above. BPA or the adjacent Path TOP includes the resolution of this adverse impact in its study report for the ATC Path. This process is defined in WECC's Operating Transfer Capability Policy Committee (OTCPC) protocols and procedures. (MOD-029 R2.5)

BPA has Transmission Ownership Agreements where multiple ownerships of Transmission rights exist on an ATC Path. TTC for the affected ATC paths is allocated according to contractual ownership rights. See section IV, "Allocation Processes," p. 8 for further details. (MOD-029 R2.6)

With the exception of the LaGrande Path, BPA does not have any ATC Paths whose Ratings were established, known, and used in operation since January 1, 1994, and no action has been taken to have the Path rated using a different method. For the LaGrande Path, BPA uses the Association from the Accepted Rating of Existing Path 14, Idaho to Northwest for the IPCO–BPA interconnection, included in the WECC Path Rating Catalog. BPA refers to the IPCO-BPA interconnection as LaGrande. (MOD-029 R2.7)

BPA creates a study report that describes the TTC applicable to the outages during the studied time period and includes the limiting Contingencies and the limiting cause for the calculated TTC. BPA's study assumptions document (SOL Methodology, Appendix C) defines the steps taken and Contingencies and assumptions BPA used to determine TTC for each ATC path. BPA creates a study report for each study it performs. The study report relies on the basic assumptions included in the SOL methodology and identifies any changes to those basic assumptions. (MOD-029 R2.8)

As described in Section III, "Overview," on p. 4, information regarding TTCs is shared electronically between the appropriate BPA organizations within seven calendar days of the finalization of the study report for the TTCs. BPA sends a notice to all TSPs for the ATC Paths listed in Table 1 where there are multiple TSPs *prior* to limitations in TTCs.

These notices are called Notices of Planned Path Limitation. Where BPA has performed a study, the notice states that the TTC study report is available to TSPs for the specific Path within seven calendar days upon request to nercatcstandard@bpa.gov with **TTC Study Report Request** in the subject line. Use the **TTC Study Report Request Form** found on BPA's website shown below to submit the request.

http://transmission.bpa.gov/business/atc_methodology/

There are three ATC Paths for which BPA does not perform studies to determine the most current value of TTC. Those Paths are the Reno – Alturas NW Sierra (RATS), La Grande and Montana Intertie ATC Paths. For RATS, Sierra Pacific Power Company determines TTC. For La Grande, Idaho Power Company determines TTC. For Montana Intertie, NorthWestern Energy sets the TTC. The TTC Ratings are provided to BPA and BPA then sends a Notice of Planned Path Limitation.

There are also three ATC Paths where both BPA and another TOP perform studies to determine/establish the most current value of TTC. Those are the California – Oregon Intertie (COI), the Pacific DC Intertie (PDCI), and the Northern Intertie. For the COI, both BPA and the California Independent System Operator (CISO) perform TTC studies. For the PDCI, both BPA and the Los Angeles Department of Water and Power (LADWP) perform TTC studies. For the Northern Intertie, both BPA and British Columbia Hydro Corporation (BCH) perform TTC studies. In these situations, the current value of TTC is determined/established as follows:

- If a TTC limitation would be caused by outages or other System conditions in the Northwest, BPA performs the necessary studies, sets the limits and shares the limits with the CISO, LADWP, or BCH, as appropriate.
- If a TTC limitation would be caused by outages or other System conditions in California or British Columbia, the CISO, LADWP, or BCH, as appropriate, perform the necessary studies, set the limits and share the limits with BPA.
- If a TTC limitation would be caused by outages or other System conditions both in the Northwest and California or the Northwest and British Columbia, BPA, CISO and/or LADWP and/or BCH, as appropriate, perform studies. The lowest TTC value determined/established in the respective studies is adopted by BPA and CISO, BPA and LADWP, or BPA and BCH. (MOD-029 R3 and R4)

Calculating Firm Transmission Service

Calculating Firm Existing Transmission Commitments (ETC_F)

When calculating ETC_F for all time periods for its ATC Paths, BPA uses the following algorithm as specified in MOD-029 R5:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses and Load growth not otherwise included in TRM or CBM.

> BPA does not use the NL_F component of the ETC_F calculation for any of its ATC Paths. All of BPA's firm Transmission obligations are included in contracts, Agreements and obligations captured in the $NITS_F$, PTP_F and GF_F components of this algorithm. Therefore BPA sets NL_F at zero for all of its ATC Paths for all time periods.

$NITS_F$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses and Load growth.

> For BPA's ATC Paths where $NITS_F$ commitments exist to serve Network Load outside BPA's BAA, the firm capacity set aside for $NITS_F$ is equal to the Load forecast, which includes losses and Load growth, minus generation outside BPA's BAA that is designated to serve that Load. For BPA's ATC Paths where $NITS_F$ commitments exist to serve Network Load inside BPA's BAA from a forecasted or designated network resource that impacts the ATC Path, the firm capacity set aside for $NITS_F$ is equal to the amount the resource is forecasted/designated for.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of BPA's Open Access Transmission Tariff (OATT).

> The amount of GF_F BPA sets aside is based on the terms of each individual contract.

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service and is equal to the sum of the PTP_F contract Demands.

> In BPA's calculations, PTP_F is equal to the sum of the MW Demands of PTP_F reservations or schedules. In some cases, BPA has PTP_F contracts that give customers the right to schedule between multiple Points of Receipt (PORs) and Points of Delivery (PODs). However, the customer can only schedule up to the MW amount specified in their contract. Multiple reservations are created for these special cases to allow BPA to model each POR-to-POD combination. The amount set aside for these cases does not exceed the total PTP_F capacity specified in the contracts.

ROR_F is the firm capacity reserved for roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

BPA assumes that all of its Transmission Service Agreements eligible to roll-over in the future will be rolled over. Therefore, ROR_F is equal to the sum of the $NITS_F$, GF_F and PTP_F obligations that are eligible for roll-over rights. If a Transmission Customer chooses not to exercise its roll-over rights by the required deadline, BPA no longer holds out capacity for roll-over rights for that Transmission Customer.

OS_F is the firm capacity reserved for any other service(s), contract(s), or Agreement(s) not specified above using Firm Transmission Service.

BPA has no other services beyond those specified above. Therefore BPA sets OS_F at zero for all of its ATC Paths for all time periods.

As a result, BPA calculates ETC_F for its ATC Paths for all time periods as follows:

$$\mathbf{ETC_F = NITS_F + GF_F + PTP_F + ROR_F}$$

While BPA includes all of the components described above in ETC_F, BPA accounts for $NITS_F$, GF_F, PTP_F and ROR_F in its ATC calculations using different variables. Descriptions of the variables for ATC_F calculations begin on page 20 and for ATC_{NF} calculations, page 25.

See Appendix D for a list of BPA's NITS, GF, and PTP Agreements.

Calculating Firm Available Transfer Capability (ATC_F)

When calculating ATC_F for its ATC Paths for all time periods, BPA uses the following algorithm (MOD-029 R7):

$$\mathbf{ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + Counterflows_F}$$

Where:

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability for that ATC Path for that time period.

See "Process to Determine TTC" beginning on p. 16, for a description of how BPA determines TTC.

ETC_F is the sum of existing firm commitments for that ATC Path during that period.

For ATC_F calculations for all time periods, BPA further divides ETC_F into the following algorithm in order to capture both its firm Long-Term and Short-Term Reservations:

$$\mathbf{ETC_F = LRES + SRES + LETC - SADJ/ETC\ Adjustments}$$

Where:

LRES is the sum of the $NITS_F$, PTP_F, ROR_F and GF_F Long-Term Reservations.

SRES is the sum of the PTP_F Short-Term Reservations.

LETC is used to make two different adjustments to ETC_F. The first adjustment is made to ensure that the amount of PTP_F capacity BPA sets aside in the LRES variable for contracts where BPA gives customers the right to schedule the capacity reserved between multiple PORs and PODs does not exceed the total PTP_F capacity specified in those contracts.

The second adjustment is made only on the West of Hatwai E>W Path. On this ATC Path, BPA uses LETC to hold out $NITS_F$ capacity for the Western Montana hydro projects (Albeni Falls, Libby, Hungry Horse and Dworshak) located east of West of Hatwai to serve Network Load west of West of Hatwai, since no reservation exists for this $NITS_F$ obligation.

SADJ/ETC Adjustments is the variable BPA uses to make adjustments to ETC_F not captured in LRES or SRES**.** On the West of Garrison Path, BPA has two PTP_F Long-Term Reservations, captured in LRES, that hold out capacity in the E>W direction. However, the energy associated with these reservations is affected by a parallel path and flows in the W>E direction as well. SADJ/ETC Adjustments is used to hold out capacity in the W>E direction to accurately account for this flow as an ETC_F adjustment.

BPA applies another such adjustment to allow for deferral competitions, as required in Section 17.7 of BPA's OATT. When a deferral reservation is confirmed, BPA applies an ETC adjustment to hold out transfer capability for the time period deferred, starting at the latter of five months out or the service commencement date of the original reservation, to allow for a competition. At four months out, if no competition is identified, the ETC adjustment is modified to post back transfer capability for the fourth month out.

BPA also uses SADJ/ETC adjustments to ensure accurate accounting of ETC_F. These adjustments may be performed to account for situations such as data modeling corrections, and will be noted in the descriptions of the adjustments.

The following diagram illustrates how the variables used in BPA's ETC_F calculations correspond to the variables contained in the ETC_F algorithm shown in "Calculating Firm Existing Transmission Commitments" beginning on p. 19.

ETC_F =	$NITS_F$	+	GF_F	+	PTP_F	+	ROR_F
	↓		↓		↓		↓
	LRES		**LRES**		**LRES**		**LRES**
	+				**+**		
					SRES		
					+		
	LETC				**LETC**		
	-		**-**		**-**		**-**
	SADJ/ETC Adjustments		**SADJ/ETC Adjustments**		**SADJ/ETC Adjustments**		**SADJ/ETC Adjustments**

CBM is the Capacity Benefit Margin for the ATC Path during that period.

BPA does not maintain CBM. Therefore BPA sets CBM at zero for all of its ATC Paths for all time periods.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

BPA maintains TRM on the Northern Intertie Path as described in its TRMID for all time periods. BPA does not maintain TRM in its ATC calculation for any other ATC Paths. Therefore, BPA sets TRM at zero for all remaining ATC Paths for all time periods.

$Postbacks_F$ are changes to ATC_F due to a change in the use of Transmission Service for that period.

Because BPA automatically recalculates ETC_F whenever there is a reduction in LRES or SRES, BPA does not use $Postbacks_F$ for calculating ATC_F on any of its ATC Paths. Therefore BPA sets $Postbacks_F$ at zero for all of its ATC Paths for all time periods.

$Counterflows_F$ are adjustments to ATC_F.

BPA does not include confirmed Transmission reservations, expected interchange or internal flow counter to the direction of the ATC Path being calculated in its ATC_F calculations. BPA's rationale is that it does not want to offer firm transfer capability due to counterflow that may not be scheduled as this could lead to Curtailments of Firm Transmission Service in the Real-time horizon. (MOD-001 R3.2) Therefore BPA sets $Counterflows_F$ at zero for all of its ATC Paths for all time periods.

As a result, BPA calculates ATC_F for all of its ATC Paths, except the Northern Intertie Path, for all time periods as follows:

$$ATC_F = TTC - ETC_F$$

BPA calculates ATC_F for the Northern Intertie Path for all time periods as follows:

$$ATC_F = TTC - ETC_F - TRM$$

Calculating Non-Firm Transmission Service

BPA sells six non-firm Transmission products. Those products are:

1. **$NITS_{NF6}$**. This is a non-firm Transmission product available only to Transmission Customers with NITS Agreements. It is the highest quality of Non-Firm Transmission Service in that it is the last Non-Firm Transmission Service that would be Curtailed, if necessary.

2. **PTP_{NF5}**. This is a non-firm Transmission product available only to Transmission Customers with PTP service Agreements. PTP_{NF5} is the fifth Non-Firm Transmission Service that would be Curtailed, if necessary.

3. **PTP_{NF4}**. This is a non-firm Transmission product available only to Transmission Customers with PTP service Agreements. PTP_{NF4} is the fourth Non-Firm Transmission Service that would be Curtailed, if necessary.

4. **PTP_{NF3}**. This is a non-firm Transmission product available only to Transmission Customers with PTP service Agreements. PTP_{NF3} is the third Non-Firm Transmission Service that would be Curtailed, if necessary.

5. **PTP_{NF2}**. This is a non-firm Transmission product available only to Transmission Customers with PTP service Agreements. PTP_{NF2} is the second Non-Firm Transmission Service that would be Curtailed, if necessary.

6. **PTP_{NF1}.** This is a non-firm Transmission product available only to Transmission Customers with PTP service Agreements. PTP_{NF1} is the first Non-Firm Transmission Service that would be Curtailed, if necessary (i.e., this Transmission Service has the highest likelihood of being Curtailed).

BPA calculates ETC_{NF} and ATC_{NF} for each of these products.

Calculating Non-Firm Existing Transmission Commitments (ETC_{NF})

BPA calculates ETC_{NF} for all time periods for an ATC Path using the following algorithm as specified in MOD-029 R6:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses and Load growth not otherwise included in TRM or CBM.

In BPA's calculations, this is $NITS_{NF6}$. It does not include losses or Load growth, since losses and Load growth are already set aside as firm capacity in $NITS_F$.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of BPA's OATT.

BPA has no grandfathered Non-Firm Transmission Service obligations. Therefore BPA sets GF_{NF} at zero for all of its ATC Paths for all time periods.

PTP_{NF} is non-firm capacity reserved or scheduled for confirmed PTP Transmission Service.

In BPA's calculations, this includes PTP_{NF5}, PTP_{NF4}, PTP_{NF3}, PTP_{NF2} and PTP_{NF1}.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or Agreement(s) not specified above using Non-Firm Transmission Service.

BPA has no other services beyond those specified above. Therefore BPA sets OS_{NF} at zero for all of its ATC Paths for all time periods.

As a result, BPA calculates ETC_{NF} for its ATC Paths for all time periods as follows:

$$\mathbf{ETC_{NF} = NITS_{NF} + PTP_{NF}}$$

While BPA includes all of the components described above in ETC_{NF}, BPA accounts for $NITS_{NF}$ and PTP_{NF} in its ATC_{NF} calculations using different variables. A description of the variables used begins on p. 28.

Calculating Non-Firm Available Transfer Capability (ATC_{NF})

BPA uses different algorithms to calculate ATC_{NF}, ETC_F, ETC_{NF} and $Postbacks_{NF}$ for two time horizons for all of its ATC Paths: Real-time and beyond Real-time. The Real-time horizon begins at 10 p.m. on the pre-schedule day for the 24 hours in the next day. ETC_F and ETC_{NF} for the Real-Time horizon are calculated using schedules and reservations that have not yet been scheduled. The beyond Real-time horizon includes hourly for the hours after those included in the Real-time period as well as daily and monthly calculations. ETC_F and ETC_{NF} for the time horizon beyond Real-time are calculated using reservations.

BPA calculates ETC_{NF} and ATC_{NF} for the six non-firm Transmission products associated with NERC Curtailment priorities (described on p. 23) as follows:

1. **ATC_{NF6}**: ATC_{NF6} is calculated for the $NITS_{NF6}$ product. ETC_{NF} in this equation only includes $NITS_{NF6}$.
2. **ATC_{NF5}**: ATC_{NF5} is calculated for the PTP_{NF5} product. ETC_{NF} in this equation includes $NITS_{NF6}$ and PTP_{NF5}.

3. **ATC_{NF4}**: ATC_{NF4} is calculated for the PTP_{NF4} product. ETC_{NF} in this equation includes $NITS_{NF6}$, PTP_{NF5} and PTP_{NF4}.

4. **ATC_{NF3}**: ATC_{NF3} is calculated for the PTP_{NF3} product. ETC_{NF} in this equation includes $NITS_{NF6}$, PTP_{NF5}, PTP_{NF4}, and PTP_{NF3}.

5. **ATC_{NF2}**: ATC_{NF2} is calculated for the PTP_{NF2} product. ETC_{NF} in this equation includes $NITS_{NF6}$, PTP_{NF5}, PTP_{NF4}, PTP_{NF3} and PTP_{NF2}.

6. **ATC_{NF1}:** ATC_{NF1} is calculated for the PTP_{NF1} product. ETC_{NF} in this equation includes $NITS_{NF6}$, PTP_{NF5}, PTP_{NF4}, PTP_{NF3}, PTP_{NF2} and PTP_{NF1}.

The following section describes how BPA calculates ATC_{NF} for each time period.

When calculating ATC_{NF} for its ATC paths for the two time horizons described above, BPA uses the following algorithm as specified in MOD-029 R8:

$$\mathbf{ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counterflow_{NF}}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

As previously described, BPA calculates six ATC_{NF} values, one for each of its six non-firm Transmission products.

TTC is the Total Transfer Capability of the ATC Path for that period.

See “Calculating Total Transfer Capability” beginning on p. 14 for a description of BPA’s process to determine TTC.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

BPA uses different algorithms to calculate ETC_F for all of its ATC Paths for the time horizon beyond Real-time and the Real-time horizon.

ETC_F for the Time Horizon Beyond Real-Time

For ATC_{NF} calculations for the time horizon beyond Real-time, BPA further divides ETC_F into the following algorithm in order to capture both its firm Long-Term and Short-Term Reservations:

$$\mathbf{ETC_F = LRES + SRES - SADJ/ETC\ Adjustments + LETC}$$

Where:

LRES is the sum of the $NITS_F$, PTP_F, ROR_F and GF_F Long-Term Reservations.

SRES is the sum of the PTP_F Short-Term Reservations.

SADJ/ETC Adjustments is the variable used to make adjustments to ETC_F not captured in LRES or SRES. On the West of Garrison Path, BPA has two PTP_F reservations, captured in LRES, that hold out capacity in the E>W direction. However, the energy associated with these reservations is affected by a parallel path and flows in the W>E direction as well. SADJ/ETC Adjustments is used to hold out capacity in the W>E direction to accurately account for this flow as an ETC_F adjustment.

BPA applies another such adjustment to allow for deferral competitions, as required in Section 17.7 of BPA's OATT. When a deferral reservation is confirmed, BPA applies an ETC adjustment to hold out transfer capability for the time period deferred, starting at the latter of five months out or the service commencement date of the original reservation, to allow for a competition. At four months out, if no competition is identified, the ETC adjustment is modified to add back transfer capability for the fourth month out.

BPA also uses SADJ/ETC adjustments to ensure accurate accounting of ETC_F. These adjustments may be performed to account for situations such as data modeling corrections, and will be noted in the descriptions of the adjustments.

LETC is used to make two different adjustments to ETC_F. The first adjustment is made to ensure that the amount of PTP_F capacity BPA sets aside in the LRES variable for contracts where BPA gives customers the right to schedule the capacity reserved between multiple PORs and PODs does not exceed the total PTP_F capacity specified in those contracts.

The second adjustment is made only on the West of Hatwai E>W Path. On this ATC Path BPA uses LETC to hold out $NITS_F$ capacity for the Western Montana hydro projects (Albeni Falls, Libby, Hungry Horse and Dworshak) located east of West of Hatwai to serve Network Load west of West of Hatwai, since no reservation exists for this $NITS_F$ obligation.

The following diagram illustrates how the variables used in BPA's ETC_F calculation correspond to the variables contained in the ETC_F algorithm shown in "Calculating Firm Existing Transmission Commitments" beginning on p.19.

ETC_F =	**$NITS_F$**	**+**	**GF_F**	**+**	**PTP_F**	**+**	**ROR_F**
	↓		↓		↓		↓
	LRES		**LRES**		**LRES**		**LRES**
					+		
					SRES		
	+				**+**		
	LETC				**LETC**		
	-		**-**		**-**		**-**

	SADJ/ETC Adjustments		SADJ/ETC Adjustments		SADJ/ETC Adjustments		SADJ/ETC Adjustments

ETC_F for the Real-Time Horizon

For ATC_{NF} calculations for the Real-time horizon, ETC_F is expressed as follows:

$$\mathbf{ETC_F = SCH^+_7 + ASC^+_7 + RADJ/ETC\ Adjustment}$$

Where:

SCH^+_7 is the sum of the positive schedules that reference confirmed $NITS_F$, GF_F and PTP_F reservations for the ATC Path for that period.

ASC^+_7 is the sum of the positive dynamic schedules that reference confirmed $NITS_F$, GF_F and PTP_F reservations for the ATC Path for that period.

RADJ/ETC Adjustment is used to adjust hourly ETC_F on the West of Hatwai E>W Path to account for a $NITS_F$ obligation (note that this obligation is accounted for in LETC in the time horizon beyond Real-time). The adjustment is equal to the difference between the BPA BAA Load estimate east of West of Hatwai and the average MW output of the western Montana hydro projects (Albeni Falls, Libby, Hungry Horse, Dworshak), located east of West of Hatwai. When this value changes +/- 50 MW in the Real-time horizon based on a change in the generation and Load estimates, for any given hour, BPA updates this ETC adjustment to reflect the new hourly value.

BPA also uses RADJ/ETC adjustments to ensure accurate accounting of ETC_F. These adjustments may be performed to account for situations such as data modeling corrections.

The following diagram illustrates how the variables used in BPA's ETC_F calculation correspond to the variables contained in the ETC_F algorithm shown in "Calculating Firm Existing Transmission Commitments" beginning on p.19. ROR_F is not included in ETC_F for the Real-time horizon because ROR_F is not relevant for the Real-time horizon.

ETC_F =	$NITS_F$	+	GF_F	+	PTP_F
	↓		↓		↓
	SCH^+_7		SCH^+_7		SCH^+_7
	+		+		+
	ASC^+_7		ASC^+_7		ASC^+_7
	+		+		+
	RADJ/ETC Adjustment		RADJ/ETC Adjustment		RADJ/ETC Adjustment

ETC_{NF} is the sum of existing non-firm commitments for the ATC Path during that period.

BPA uses different algorithms to calculate ETC_{NF} for all of its ATC Paths for the time horizon beyond Real-time and the Real-time horizon.

ETC_{NF} for the Time Horizon Beyond Real-Time

For ATC_{NF} calculations in the time horizon beyond Real-time, ETC_{NF} is expressed as follows:

$$ETC_{NF} = RRES_{6,5,4,3,2,1}$$

Where:

$RRES_{6,5,4,3,2,1}$ is the sum of all confirmed $NITS_{NF6}$, PTP_{NF5}, PTP_{NF4}, PTP_{NF3}, PTP_{NF2} and PTP_{NF1} reservations.

The following diagram explains how the variables used in BPA's ETC_{NF} calculation correspond to the variables contained in the ETC_{NF} algorithm shown in "Calculating Non-Firm Existing Transmission Commitments" beginning on p. 23.

ETC_{NF} =	$NITS_{NF}$	+	PTP_{NF}
	↓		↓
	$RRES_{6,5,4,3,2,1}$		$RRES_{6,5,4,3,2,1}$

ETC_{NF} for the Real-Time Horizon

For ATC_{NF} calculations in the Real-time horizon, ETC_{NF} is expressed as follows:

$$ETC_{NF} = SCH^{+}_{6,5,4,3,2,1} + ASC^{+}_{6,5,4,3,2,1}$$

Where:

$SCH^{+}_{6,5,4,3,2,1}$ is the sum of the positive Demands of schedules referenced to confirmed $NITS_{NF6}$, PTP_{NF5}, PTP_{NF4}, PTP_{NF3}, PTP_{NF2} and PTP_{NF1} reservations, plus the sum of the positive Demands of confirmed $NITS_{NF6}$, PTP_{NF5}, PTP_{NF4}, PTP_{NF3}, PTP_{NF2} and PTP_{NF1} reservations that have not yet been scheduled. Once these reservations are scheduled, the schedule is used for ETC_{NF}, thereby adding back the difference between the reservation and schedule amounts to ATC_{NF}.

$ASC^{+}_{6,5,4,3,2,1}$ is the sum of positive Demands of dynamic schedules referenced to confirmed $NITS_{NF6}$, PTP_{NF5}, PTP_{NF4}, PTP_{NF3}, PTP_{NF2} and PTP_{NF1} reservations for the ATC Path.

The following diagram explains how the variables used in BPA's ETC_{NF} calculation correspond to the variables contained in the ETC_{NF} algorithm shown in "Calculating Non-Firm Existing Transmission Commitments" beginning on p. 23.

ETC_{NF} =	$NITS_{NF}$	+	PTP_{NF}
	↓		↓
	$SCH^{+}_{6,5,4,3,2,1}$		$SCH^{+}_{6,5,4,3,2,1}$
	+		+
	$ASC^{+}_{6,5,4,3,2,1}$		$ASC^{+}_{6,5,4,3,2,1}$

CBM_S is the Capacity Benefit Margin that has been scheduled for the ATC Path during that period.

BPA does not maintain CBM. Therefore BPA sets CBM_S at zero for all of its ATC Paths for all time periods.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale as non-firm capacity during that period.

BPA does not release TRM for the Northern Intertie Path as non-firm capacity, as described in BPA's TRMID. BPA does not maintain TRM in its ATC calculation for any other ATC Paths. Therefore BPA sets TRM_U for the Northern Intertie Path as described in its TRMID and at zero for all other ATC Paths for all time periods.

$Postbacks_{NF}$ are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period.

BPA uses different algorithms to calculate $Postbacks_{NF}$ for all of its ATC Paths for the time horizon beyond Real-time and the Real-time horizon.

$Postbacks_{NF}$ for the Time Horizon Beyond Real-time

BPA does not use $Postbacks_{NF}$ for calculating ATC_{NF} for any of the ATC Paths for the time horizon beyond Real-time. Therefore BPA sets $Postbacks_{NF}$ at zero for all of its ATC Paths for the time horizon beyond Real-Time.

$Postbacks_{NF}$ for the Real-time Horizon

For ATC_{NF} calculations in the Real-time horizon, there are circumstances in which BPA uses $Postbacks_{NF}$, expressed as RADJ/ETC.

One such postback is applied to hourly calculations on the West of Garrison E>W Path. In situations where schedules exceed the SOL on the West of Garrison E>W Path, BPA may post back up to 200 MW of capacity because of the RAS on that Path associated with Miles City Load. The exact capacity from Miles City available to be posted back to ATC_{NF} is determined by nomograms selected by BPA's RAS dispatcher for different System conditions. See Dispatcher Standing Order No. 319, Montana – Pacific Northwest Remedial Action Scheme, (Appendix E of this ATCID) for further information.

Another postback is applied to the COI N>S Path. For its hourly COI N>S non-firm calculations, BPA posts back any unused share of non-firm capacity that is available to BPA by capacity ownership and other Agreements for the COI N>S, if needed to prevent Curtailments.

For all other ATC Paths, there are no other Postbacks expressed as RADJ/ETC.

Counterflow$_{NF}$ are adjustments to ATC_{NF}.

Since a schedule provides assurance that the transaction will flow, all counterflow resulting from firm and non-firm Transmission schedules, excluding tag types dynamic and capacity, are added back to ATC_{NF} in the Counterflows$_{NF}$ component. (MOD-001 R3.2)

In BPA's ATC_{NF} calculations, Counterflows$_{NF}$ is expressed as $SCH^{-}_{7,6,5,4,3,2,1}$, which is the sum of schedules flowing in the direction counter to the direction of the ATC Path.

As a result, BPA calculates ATC_{NF} for all of its ATC Paths, except the Northern Intertie Path, for all time periods as follows:

$$\mathbf{ATC_{NF} = TTC - ETC_{F} - ETC_{NF} + Postbacks_{NF} + Counterflows_{NF}}$$

BPA calculates ATC_{NF} for its Northern Intertie Path for all time periods as follows:

$$\mathbf{ATC_{NF} = TTC - ETC_{F} - ETC_{NF} - TRM_{U} + Postbacks_{NF} + Counterflows_{NF}}$$

In some cases, the amount of Counterflows$_{NF}$ exceeds the sum of the ETC_{F} and ETC_{NF}, which, when added to TTC, results in ATC_{NF} greater than TTC.

Note: The variable RADJ/ETC is also used to respond to a BPA dispatcher order to change ATC values by a specified amount and thereby reduce schedules in-hour when the flow exceeds the SOL.

VIII. Flowgate Methodology

This section describes in detail how BPA implements the Flowgate Methodology. It addresses all of the requirements in Standard MOD-030-02.

BPA Flowgates

The following table shows the Flowgates for which BPA uses the Flowgate Methodology:

Table 2

BPA Flowgates

Flowgate	Direction	Transmission Line Components
North of Hanford On OASIS: NOHANF	(N>S)	Vantage-Hanford 500kV; Grand Coulee-Hanford 500kV; and

Flowgate	Direction	Transmission Line Components
		Shultz-Wautoma 500kV
North of Hanford On OASIS: NOHANF	(S>N)	Vantage-Hanford 500kV; Grand Coulee-Hanford 500kV; and Shultz-Wautoma 500kV
South of Allston On OASIS: SOALSN	(N>S)	BPA -Owned Transmission Lines: Keeler-Allston 500kV; Lexington-Ross 230kV; and St. Helens-Allston 115kV; Portland General Electric -Owned Transmission Lines: Trojan-St. Marys 230kV; and Trojan-River Gate 230kV; PacifiCorp-Owned Transmission Lines: Merwin-St. Johns 115kV; Astoria-Seaside 115kV; and Clatsop 230/115kV
South of Allston On OASIS: SOALSN	(S>N)	BPA -Owned Transmission Lines: Keeler-Allston 500kV; Lexington-Ross 230kV; and St. Helens-Allston 115kV; Portland General Electric -Owned Transmission Lines: Trojan-St. Marys 230kV; and Trojan-River Gate 230kV; PacifiCorp-Owned Transmission Lines: Merwin-St. Johns 115kV; Astoria-Seaside 115kV; and Clatsop 230/115kV
North of John Day On OASIS: NOJDAY	(N>S)	Ashe-Marion 500kV; Ashe-Slatt 500kV; Wautoma-Ostrander 500kV; Wautoma-Rock Creek 500kV; Raver-Paul 500kV; and Lower Monumental-McNary 500kV.
Paul-Allston On OASIS: PAUL_ALSN	(N>S)	Napavine-Allston #1 500kV; and Paul-Allston #2 500kV.
Raver-Paul On OASIS: RAVR_PAUL	(N>S)	Raver-Paul 500 kV Line During outage conditions, the following lines are monitored: Raver – Paul #1 500-kV; Olympia – South Tacoma #1 230kV; Chehalis – Covington #1 230kV;

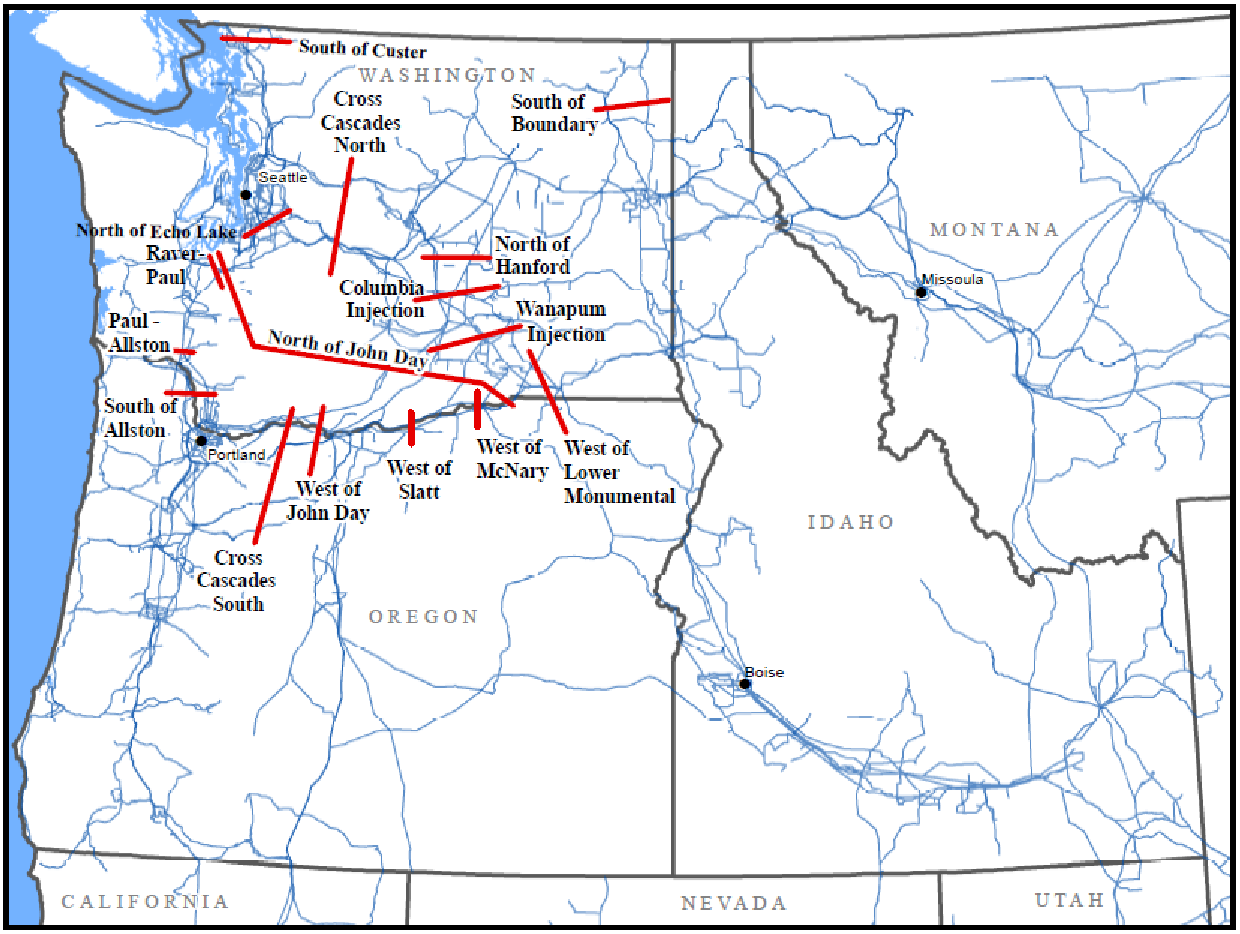
Flowgate	Direction	Transmission Line Components
		Puget Sound Energy-Owned Transmission Lines: Frederickson– St. Clair 115kV; Electron Heights – Blumaer 115kV
Cross Cascades North On OASIS: C-CASC_N	(E>W)	BPA-Owned Transmission Lines Schultz-Raver #1, 3, & 4 500kV; Schultz-Echo Lake #1 500kV; Chief Joseph-Monroe 500kV; Chief Joseph-Snohomish #3 & 4 345kV; Rocky Reach-Maple Valley 345kV; Grand Coulee-Olympia 287kV; Bettas Road - Covington #1 230kV. Puget Sound Energy-Owned Transmission Line Rocky Reach – Cascade 230 kV
Cross Cascades South On OASIS: C-CACS_S	(E>W)	Big-Eddy-Ostrander 500kV; Ashe-Marion 500kV; Buckley-Marion 500kV; Wautoma-Ostrander 500kV; John Day-Marion 500kV; McNary-Ross 345kV; Big Eddy-Chemawa 230kV; Big Eddy-McLoughlin 230kV; Midway-North Bonneville 230kV; Jones Canyon-Santiam 230kV; and Big Eddy-Troutdale 230kV PGE-Owned Transmission Line Bethel – Round Butte 230 kV
West of McNary On OASIS: WOMCNY	(E>W)	Coyote Springs-Slatt 500kV; McNary-Ross 345kV; Harvalum – Big Eddy #1 230 kV; Jones Canyon-Santiam 230kV; and McNary-John Day #2 500kV
West of Slatt On OASIS: WOSLATT	(E>W)	Slatt-Buckley 500kV; and Slatt-John Day 500kV
West of John Day On OASIS: WOJD	(E>W)	John Day – Big Eddy No. 1 500-kV line (metered at John Day); John Day – Big Eddy No. 2 500-kV line (metered at John Day); and John Day – Marion No. 1 500kV
South of Boundary On OASIS: SOB	(N>S)	Bell – Boundary #1 230kV; Bell – Boundary #3 230kV; Usk – Boundary #1 230kV; and

Flowgate	Direction	Transmission Line Components
		Boundary 230/115kV Transformer #1
Columbia Injection On OASIS: CI	(N>S)	Columbia-Grand Coulee #1 230-kV (metered at Columbia); Columbia-Grand Coulee #3 230-kV (metered at Columbia); Rocky Reach-Columbia #1 230-kV (metered at Columbia); Rocky Reach-Columbia #2 230-kV (metered at Columbia); Columbia-Valhalla #1 115-kV (metered at Columbia); and Columbia-Valhalla #2 115-kV (metered at Columbia)
Wanapum Injection On OASIS: WI	(N>S)	Midway-Vantage #1 230-kV; and Midway-Priest Rapids #3 230-kV
West of Lower Monumental On OASIS: WOLM	(E>W)	Ashe – Lower Monumental 500kV; Hanford – Lower Monumental 500kV; and McNary – Lower Monumental 500kV
North of Echo Lake On OASIS: NOEL	(S>N)	Echo Lake – Monroe - SnoKing Tap #1 500kV; Echo Lake – Maple Valley #1 500 kV; Echo Lake – Maple Valley #2 500kV; and Covington – Maple Valley #2 230kV
South of Custer On OASIS: SOC	(N>S)	Monroe - Custer #1 500kV; Monroe - Custer #2 500kV; Bellingham - Custer #1 230kV; and Murray - Custer #1 230kV Line

The following map shows the general geographic locations of the Flowgates listed in Table 2, above:

Figure 3

BPA Network Flowgate Map



History of Flowgates

BPA's use of Flowgates predates the development and effective date of the NERC Flowgate Methodology (MOD-030) Standard. BPA's current Flowgates meet the criteria described below for the first Contingency transfer analysis.

Identifying Facilities as Flowgates

BPA establishes a list of Flowgates by creating, deleting, verifying or modifying Flowgate definitions at least once per calendar year, using the process described below. (MOD-030 2.2) To identify sets of Transmission Facilities as BPA Flowgates to be considered in its AFC calculations, BPA performs seasonal studies.

As part of its seasonal studies, BPA analyzes ATC Paths internal to its System, up to the Path capability, such that at least the most limiting Element in a series configuration is included as a Flowgate. (MOD-030, R2.1.1) In its seasonal studies, BPA also analyzes its interfaces with its adjacent BAs where BPA has elected to use the Flowgate Methodology, up to the Path capability, such that at least the most limiting Element in a series configuration is included as a BPA Flowgate. (MOD-030 R2.1.1.2, MOD-030 R2.1.2.2)

The following table lists all of the BAs adjacent to BPA, the interfaces that are included in BPA's seasonal studies and accounted for using the Flowgate Methodology and the interfaces that are accounted for using the Rated System Path Methodology:

Table 3
Interfaces with BAs Adjacent to BPA

BA adjacent to BPA	Interfaces accounted for using the Flowgate Methodology and included in BPA's seasonal studies	Interfaces accounted for using the Rated System Path Methodology
Avista Corporation	X	X
City of Tacoma Department of Public Utilities, Light Division	X	
PacifiCorp	X	X
Portland General Electric	X	
Public Utility District No. 1 of Chelan County	X	
Public Utility District No. 2 of Grant County, Washington	X	
Public Utility District No. 1 of Douglas County	X	
Puget Sound Energy Inc.	X	
Seattle City Light	X	
BC Hydro		X
California Independent System Operator		X
Idaho Power Company		X
Los Angeles Department of Water and Power		X
NorthWestern Energy		X
Sacramento Municipal Utility District		X
Sierra Pacific Power Co.		X

Note: BPA uses both methodologies to account for its multiple interfaces with Avista Corporation and PacifiCorp.

For each of its existing Flowgates, BPA has a list of single Contingencies and credible double Contingencies. Each of these lists encompasses a wide section of the Transmission System around the particular Flowgate. The Contingencies include both Transmission Facilities and generator Contingencies, as appropriate. The Contingency lists include both BPA and non-BPA Facilities, as well as both series and parallel Facilities. BPA monitors all lines and transformers in the WECC base cases that are in proximity to the Flowgate for thermal overloads as part of the study.

These Contingencies are then incorporated into BPA's planning of operations using the first and second Contingency criteria used to establish the SOL for the Flowgate. BPA uses the same studies to establish its TFC values as it does to determine its SOL values for the applicable time period. Any Special Protection Systems associated with the Contingencies are included in the analysis. (MOD-030 R2.1.1.1) All Limiting Elements are kept within their limits for their associated worst Contingency from the Contingency list by operating within the limits of the associated Flowgate or, in some cases, the associated Path. BPA uses an OTDF criterion of 3% for its planning of operations. If the Flowgate SOL is determined by voltage or transient Stability criteria, then these same results are used to establish the corresponding TFC. Hence, when taken as a whole, the analysis of all these Flowgates and Paths effectively addresses the entire BPA Transmission System.

The Contingency lists described above for each Flowgate include the Facilities that comprise the interfaces between BPA and the relevant adjacent BAs in the area. The Facilities comprising these interfaces are kept within their limits for their associated worst Contingencies by keeping the associated Flowgate and/or Path within its operating limit. (MOD-030 R2.1.2.1).

BPA uses the following two additional criteria when conducting its seasonal studies to determine whether sets of Transmission Facilities should be identified as Flowgates to be considered in AFC calculations:

1. If a single line or group of lines where the most limiting Facility(ies) for the time period being studied (with an OTDF of at least 5 percent) can be kept within its limit for an associated worst N-1 or N-2 Contingency by operating within the limits of another Flowgate, Path, or generation dispatch, then no new Flowgate needs to be established for those lines. (MOD-030 R2.1.2.3, MOD-030 R1.1)

2. If generation and/or Transmission Facilities associated with Transmission Service that is denied for more than 24 hours in the last 12 months are not yet energized, then no new Flowgate needs to be established for such denied service. (MOD-030 R1.1)

As part of its seasonal studies, BPA analyzes whether all Limiting Elements are kept within their limit for their associated worst Contingency by operating within the limits of existing Flowgates, Paths, or generation dispatch. If any Limiting Element is not accounted for by existing Flowgates, Paths or generation dispatches, BPA will incorporate the Limiting Element into an existing Flowgate or Path or, if necessary, create a new Flowgate. (MOD-030 R2.1.1.3). (MOD-030 R2.1.2)

BPA has no Limiting Element/Contingency combinations within the WECC Reliability Coordinator's (RC) Area that have been subjected to Interconnection-wide congestion management procedures in the last 12 months. (MOD-030 R2.1.3)

BPA has not received any requests from any other TSPs to include a Limiting Element/Contingency combination within the WECC base cases as a Flowgate. (MOD-030 R2.1.4)

For a TSP to officially request BPA to include as a BPA Flowgate a Limiting Element/Contingency combination within the Pacific Northwest, the TSP must fill out the **Flowgate Analysis Request Form** (MOD-030 R2.1.4) found on BPA's website http://transmission.bpa.gov/business/atc_methodology/.

A completed request form should be sent to nercatcstandards@bpa.gov with **Flowgate Analysis Request** (MOD-030-2 R2.1.4) in the subject line.

BPA will respond within 30 days to an official request from a TSP. A request is considered *official* once the following criteria are met: (MOD-030 R2.3 and R2.1.4)

- The requesting TSP is using the Flowgate Methodology or Area Interchange Methodology. (MOD-30 R2.1.4)
- The requesting TSP already includes the Limiting Element/Contingency combination in its methodology. (MOD-30 R2.1.4.2)
- BPA has not already addressed the coordination of the Limiting Element/Contingency combination through a different methodology, (MOD-30 R2.1.4.1) and
    - o Any generator within the requesting TSP's area has at least a 5 percent PTDF or OTDF impact on the Flowgate when delivered to the aggregate Load of its own area, or
    - o A transfer from any BA within the requesting TSP's area to an adjacent BA has at least a 5 percent PTDF or OTDF impact on the Flowgate.
- The requesting TSP has followed the BPA process described above for requesting a Limiting Element/Contingency combination to be included as a BPA Flowgate.

For Limiting Element/Contingency combinations identified as meeting the criteria above, BPA will add the Flowgate and use the AFC provided by the TSP that calculates AFC for that Flowgate. (MOD-030 R5.3)

After BPA identifies a need for a new Flowgate, BPA takes certain steps to pre-build the Flowgate in its commercial and operational systems prior to the full implementation of the Flowgate on its effective date.

Establishing Total Flowgate Capability (TFC)

BPA establishes the TFC for each of its Flowgates through the following processes:

BPA uses the WECC base cases and modifies them to determine the SOL for each Flowgate for all time periods. When establishing the TFC for each of its Flowgates, BPA uses the SOL of the Flowgate for each time period, regardless of whether the Flowgate is thermally, voltage or Stability-limited. (MOD-030 R2.4)

At a minimum, BPA will review the TFC for each of its Flowgates at least once per calendar year, and will revise it if System changes occur. (MOD-030 R2.5)

If BPA receives official notification from a Transmission Owner of a change in Rating that has an impact on the TFC of a Flowgate used in BPA's AFC process, BPA conducts the appropriate review within seven calendar days of the notification. For a Transmission Owner to officially notify BPA of a change in Rating, the Transmission Owner must fill out the **Rating Change Notification Form** found on BPA's website and send it to nercatcstandards@bpa.gov with **Rating Change Notification** (MOD-030-2 R2.5.1) in the subject line. (MOD-030 R2.5.1)

BPA incorporates outages into its TFC calculations. Please refer to Section V, "Outages," beginning on p. 8, and Section VI, "SOL Priorities Used to Set TTC and TFC" beginning on p. 10 for further details on BPA's TFC calculation process. (MOD-001 R3.6)

As described in Section III, "Overview," on p. 4, information regarding TFCs is shared electronically between the appropriate BPA organizations within seven calendar days of the establishment of the TFCs. (MOD-030 R2.6)

Determining Existing Transmission Commitments

Use of WECC Base Cases to Determine ETC

As described in "BPA's Use of Western Electricity Coordinating Council Base Cases" on p. 5, BPA uses the WECC base cases and modifies them to calculate the ETC components of the AFC calculations for its Flowgates. (MOD-030 R5.1) BPA refers to these cases as ETC Cases.

The WECC base cases include generation and Transmission expected to be in service or available for service for the time period considered. The WECC base cases reflect input from the WECC Significant Additions Report, which details retirements and new additions, including those from other TSPs. BPA models new Transmission additions for its own System in the WECC base cases as out of service until the energization date is within 0-16 days out, which is the time period BPA has determined provides enough certainty about the date of energization. (MOD-030 R5.2)

The WECC base cases that BPA uses meet the following criteria:

> The WECC base cases include generator data in the power flow with generation maximum (Pmax) reflecting the capability of the units. Under no circumstances is Pmax greater than the maximum capability of the unit. BPA always uses the power flow (Pgen) or optimal output of the generator at or within the Pmax and Pmin Ratings for generators that are in service. Within each base case, the individual Generator Owners are identified by numeric code. (MOD-030 R3.1)
>
> The WECC base cases contain explicit modeling data and System topology for all Facilities within the WECC RC Area, including AC Transmission Lines 115kV and above and all DC Transmission Lines. For more information on the Facilities included in the WECC base cases, refer to "BPA's Use of Western Electricity Coordinating Council Base Cases" on p. 5. Significant looped Transmission Lines rated at less than 115 kV are also included in the WECC base cases. (MOD-030 R3.4)
>
> The WECC RC Area covers the entire Western Interconnection and contains modeling data and System topology beyond the WECC RC Area. (MOD-030 R3.5)

BPA updates the relevant WECC base cases with expected Transmission outages 161 kV and above that have an impact on PTDFs as well as newly-energized generation and Transmission for AFC calculations at least once per day for intra-day, next day and days two through 30. (MOD-030 R3.2)

BPA updates the relevant WECC base cases with expected Transmission outages 161 kV and above that have an impact on PTDFs as well as newly-energized generation and Transmission for AFC calculations at least once per month for months two through 13. (MOD-030 R3.3)

Outages in ETC Calculations

Generation outages known to BPA at the time BPA creates its ETC Cases are incorporated into the generation dispatch assumptions in the cases. See "Determining Base ETC_{Fi}" beginning on p. 42 for a description of how BPA develops its ETC Cases.

BPA adjusts the WECC base cases to include Transmission outages for BPA's area and all adjacent TSP areas to calculate PTDFs, which are used in BPA's ETC calculations. Note that BPA has no executed coordination Agreements with other TSPs. (MOD-030 R5.2, MOD-001 R3.6).

Outage Criteria in ETC Calculations

BPA uses the outage planning timeline described in Section V, "Outages," beginning on p. 8. The following criteria determine which outages are incorporated into BPA's hourly, daily and monthly ETC calculations: (MOD-001 R3.6, MOD-030 R5.2)

Hourly ETC Calculations

For its hourly ETC calculations, BPA uses the most recent hourly PTDFs calculated. Transmission outages for Transmission Lines, sections of Transmission Lines, and taps are used to set branches as *open* in the appropriate base case for the hour being calculated.

Daily ETC Calculations

For its daily ETC calculations, BPA uses the most recent PTDFs calculated for the hour ending 11, since hour ending 11 tends to have the highest coincidence of outages. Therefore all Transmission outages scheduled to occur during the hour ending 11, regardless of the duration of the outage, impact daily ETC calculations. (MOD-001 R3.6.1)

BPA does not generally consider generation or Transmission outages in daily ETC calculations beyond the 10- to 16-day planned outage study period because of the lack of certainty about planned outages scheduled for that period, unless the planned outage is scheduled to continue beyond the planned outage study period, or there is an outage that has been scheduled in BPA's outage system to begin beyond the 10- to 16-day period.

Monthly ETC Calculations

For its monthly ETC calculations, BPA uses the most recent daily PTDFs calculated for the first Tuesday of that month. BPA does not generally consider generation or Transmission outages in monthly ETC calculations beyond the 10- to 16-day planned outage study period because of the lack of certainty about outages scheduled for the period beyond the 10- to 16-day planned outage study period, unless the completion of an outage that begins in the 10- to 16-day planned outage study period is scheduled into the monthly horizon, or there is an outage that has been scheduled in BPA's outage system to begin beyond the 10- to 16-day period. (MOD-001 R3.6.2)

PTDF Analysis and *De Minimis*

BPA determines the impact of ETC on its Flowgates using PTDF analysis. PTDF analysis is the fraction of energy (expressed as a percentage or as a decimal) that will flow across BPA's monitored Flowgates as that energy is injected at a POR (or source) relative to a slack bus, and withdrawn at a POD (or sink) relative to a slack bus, for each Flowgate. The Flowgate impacts are determined using the following formula:

(POR PTDF – POD PTDF) * Demand = MW impact to Flowgate

If a reservation's impact on a Flowgate is less than or equal to 10 MW and less than or equal to 10 percent of the reserved demand, the reservation is deemed to have a *de minimis* impact on that Flowgate. Ten percent is the percentage used to curtail in the Western Interconnection-wide congestion management procedure. When using reservations, BPA does not account for *de minimis* MW amounts in its ETC calculations.

Source/POR and Sink/POD Identification and Mapping

In the ETC components of its AFC calculations, BPA accounts for source and sink for Transmission Service through the following processes:

BPA maps the source/POR and sink/POD to the WECC base cases. In this mapping, BPA has assigned network bus points that represent the primary interface for Interconnection with specific generation projects, adjacent electrical Systems or Load-serving entities and trading hubs. Some adjacent electrical Systems have multiple Interconnection points deemed as PORs/sources or PODs/sinks. The mapping of these points is published in the Transmission Service Contract Points list on BPA's OASIS homepage. (MOD-030 R1.2.3)

The source used in BPA's AFC calculations of transactions within BPA's BAA is obtained from the POR field for Short-Term Reservations and the source field for Long-Term Reservations, as shown on the TSR template in OASIS. The source used in BPA's AFC calculations of transactions for all adjacent TSPs is obtained from the source field if a source is identified, or the POR field if only the POR is identified. (MOD-030 R1.2.1) BPA represents the impact of Transmission Service using the source or POR as follows:

- If the source or POR has been identified in the reservation and is discretely modeled in the WECC base cases, BPA uses the discretely modeled point as the source. (MOD-030 R4)

- In cases where the source or POR has been identified in the reservation and the point can be mapped to an "equivalent" or "aggregate" representation in the WECC base cases, BPA maps the source to the equivalence point in the WECC base cases. These points are published in the Transmission Service Contract Points List on BPA's OASIS home page. (MOD-030 R4)
- If the source or POR has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the WECC base cases, BPA uses the immediately adjacent BA associated with the TSP from which the power is to be received as the source. (MOD-030 R4)
- BPA requires a specified source or POR to be identified for all reservations. (MOD-030 R4)

The sink used in BPA's AFC calculations of transactions within BPA's BAA is obtained from the POD field for Short-Term Reservations and the sink field for Long-Term Reservations, as shown on the TSR template in OASIS. The sink used in BPA's AFC calculations of transactions for all adjacent TSPs is obtained from the sink field if a sink is identified, or the POD field if only the POD is identified. (MOD-030 R1.2.2) BPA represents the impact of Transmission Service using the sink or POD as follows:

- If the sink or POD has been identified in the reservation and is discretely modeled in the WECC base cases, BPA uses the discretely modeled point as the sink or POD. (MOD-030 R4)
- In cases where the sink or POD has been identified in the reservation and the point can be mapped to an "equivalent" or "aggregate" representation in the WECC base case, BPA maps the sink or POD to the equivalence points in the WECC base cases. These points are published in the Transmission Service Contract Points list on BPA's OASIS home page. (MOD-030 R4)
- If the sink or POD has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the WECC base cases, BPA uses the immediately adjacent BA associated with the TSP receiving the power as the sink or POD. (MOD-030 R4)
- BPA requires a specified sink or POD to be identified for all reservations. (MOD-030 R4)

BPA has grouped the FCRPS generators in BPA's BAA based on the primary interface between BPA and the generation projects. This grouping is assigned a weighted PTDF that represents how the generators participate in the group. The weighted PTDF for the FCRPS bus point is derived from a "weighted FCRTS" bus point. The PTDF weighting for this point varies across different time periods. For the daily and monthly calculations beyond 16 days out, BPA derives the weighting of the PTDF by applying the generation dispatch determined in the ETC Cases. For the hourly and daily calculations for the next hour out to day 16, the PTDF weighting is derived from generation forecasts of the federal resources produced for that time period. (MOD-030 R1.2.4)

BPA has also grouped the FCRPS generators in the Idaho Power Company BAA based on the primary interface between Idaho Power Company and the generation projects. These groupings are assigned a weighted PTDF that represent how the generators participate in the group and are used to evaluate transactions within and between adjacent BAAs that do not include BPAT. BPA derives the PTDF weighting for this point by applying the generation dispatch determined in the ETC Cases. In the ETC Cases, these generators are modeled up to the long-term firm Transmission rights associated with the generators. (MOD-030 R1.2.4)

BPA has grouped the generators in its adjacent BAAs based on the primary interface between each BAA and the generation projects within that BAA (excluding some remote generators that are scheduled via NERC e-Tag). These groupings are assigned weighted PTDFs that represent how the generators participate in the group and are used to evaluate transactions within and between adjacent BAAs that do not include BPAT. BPA derives the PTDF weightings for these points from BAA-provided generation estimates or by applying the generation dispatch determined in the ETC Cases if generation estimates are not available. In the ETC Cases, these generators are modeled up to the long-term firm Transmission rights associated with the generators. (MOD-030 R1.2.4)

Calculating Firm Transmission Service

Calculating Firm Existing Transmission Commitments (ETC_{Fi})

When calculating the impact of ETC_{Fi} for all time periods for a Flowgate, BPA uses the following algorithm as described in MOD-030 R6:

$$\mathbf{ETC_{Fi} = NITS_{Fi} + PTP_{Fi} + ROR_{Fi} + GF_{Fi} + OS_{Fi}}$$

Where:

$NITS_{Fi}$ is the impact of firm Network Integration Transmission Service, including impacts of generation to Load for BPA's area. This impact is based on the Load forecasts for Network Service Load for the time period being calculated and the generation dispatch, which includes forecasted and designated network resources. (MOD-030 R6.1)

$NITS_{Fi}$ also includes the impact of firm Network Integration Transmission Service, including impacts of generation to Load for all of BPA's adjacent TSP areas. This impact is based on the Load forecasts for Network Service Load for the time period being calculated and the generation dispatch, which includes designated network resources. (MOD-030 R6.2)

BPA does not have coordination Agreements with other TSPs. (MOD-030 R6.2)

PTP_{Fi} is the impact of confirmed firm Point-to-Point Transmission Service expected to be scheduled in BPA's area. (MOD-030 R6.3)

PTP_{Fi} also includes the impact of confirmed Point-to-Point Firm Transmission Service expected to be scheduled for all of BPA's adjacent TSP areas.

There are no reservations using Transmission Service from multiple TSPs, and therefore no duplicate impacts, since reservations source and sink within the same TSP's area. A separate reservation is required to acquire Transmission Service over another TSP's area. When using schedules, BPA includes all schedules for all of its adjacent TSP areas, regardless of their PTDF analysis impact on BPA's Flowgates. (MOD-030 R6.4)

BPA does not have coordination Agreements with other TSPs. (MOD-030 R6.4)

ROR_{Fi} is the impact of roll-over rights for Firm Transmission Service contracts for BPA's area. BPA assumes that all of its Transmission Service Agreements eligible to roll-over in the future will be rolled over. Therefore the impact of the roll-over rights for Transmission contracts in BPA's area is calculated based on the $NITS_{Fi}$, GF_{Fi} and PTP_{Fi} obligations that are eligible for roll-over rights. For reservations that are eligible for roll-over rights, BPA creates a reservation in the form of a Transmission Service Number (TSN), with a Demand equal to the amount eligible to roll-over. BPA models these reservations in its ETC Cases. For TSNs that were not modeled in the ETC Cases, BPA derives the Flowgate impacts of these reservations using PTDF analysis. If BPA's customers choose not to exercise their roll-over rights by the required deadline, BPA no longer holds out capacity for roll-over rights for that customer. (MOD-030 R6.3)

ROR_{Fi} also includes roll-over rights for Firm Transmission Service contracts for all of BPA's adjacent TSPs. BPA assumes that all Long-Term Reservations for all of BPA's adjacent TSP areas will be rolled over. (MOD-030 R6.4)

BPA does not have coordination Agreements with other TSPs. (MOD-030 R6.4)

GF_{Fi} is the impact of grandfathered firm obligations expected to be scheduled or expected to flow for BPA's area. (MOD-030 R6.5)

GF_{Fi} also includes the impact of grandfathered firm obligations expected to be scheduled or expected to flow for all of BPA's adjacent TSP areas. (MOD-030 R6.6)

BPA does not have coordination Agreements with other TSPs. (MOD-030 R6.6)

OS_{Fi} is the impact of other firm services.

BPA has no other firm services beyond those specified above. Therefore BPA sets OS_{Fi} at zero for all of its Flowgates for all time periods. (MOD-030 R6.7)

As a result, BPA calculates ETC_{Fi} for all of its Flowgates for all time periods as follows:

$$\mathbf{ETC_{Fi} = NITS_{Fi} + PTP_{Fi} + GF_{Fi} + ROR_{Fi}}$$

When using reservations, BPA further divides the ETC_{Fi} described previously into two components: the base ETC_{Fi} values determined using the ETC Cases, and interim ETC_{Fi} impacts determined using PTDF analysis. These components are added together to calculate a final ETC_{Fi}.

As described in "PTDF Analysis and *De Minimis*" on p. 40, *de minimis* MW amounts of reservations that were not modeled in the ETC Cases are not accounted for when calculating ETC_{Fi} using reservations. However, all schedules are accounted for in ETC_{Fi} regardless of their PTDF analysis impact on BPA's Flowgates when calculating ETC_{Fi} using schedules.

While BPA includes all of the components described above in ETC_{Fi}, BPA accounts for $NITS_{Fi}$, GF_{Fi}, PTP_{Fi} and ROR_{Fi} in its AFC calculations using different variables. For descriptions of the variables used see p. 48 and p. 54.

See Appendix D for a list of BPA's NITS, GF and PTP Agreements.

Determining Base ETC_{Fi}

As indicated in "Use of the WECC Base Cases to determine ETC" beginning on p. 38, BPA creates heavy load ETC Cases for the months of January, May, June, and August and light load ETC Cases for the month of January as representative seasons to calculate base ETC_{Fi} values. BPA's ETC Cases are produced using a power flow model that computes how much power will flow over each Flowgate for the assumed Load and generation levels for each season. Counterflows are inherently modeled in these cases.

In ETC Cases, BPA models all of its own $NITS_{Fi}$, GF_{Fi} and PTP_{Fi} Long-Term Reservations, as well as those of its adjacent TSPs, active at the time the ETC Cases are produced. (MOD-030 R6)

To model the impact of PTP_{Fi} long-term reservations for all of its adjacent TSPs, BPA queries a list of PTP_{Fi} long-term reservations from the OASIS of its adjacent TSPs. To model the impact of GF_{Fi} and $NITS_{Fi}$ long-term obligations for all of BPA's adjacent TSPs, BPA contacts its adjacent TSPs and requests a list of their GF_{Fi} obligations and a list of their $NITS_{Fi}$ with a list of designated network resources with the MW amounts designated to serve Network Service and Native Load.

BPA models the $NITS_{Fi}$, GF_{Fi} and PTP_{Fi} Long-Term obligations of all of its adjacent TSPs to the extent that there are sufficient firm Transmission rights on BPA's or its adjacent TSPs' Transmission Systems to serve the Load. (MOD-30 R6.2, MOD-030 R6.4, MOD-030 R6.6)

BPA uses the following assumptions to create ETC Cases for its ETC_{Fi} calculations:

System topology: Normal operating conditions are used.

Load: BPA uses Loads contained in the WECC base cases for the time periods being studied, along with any updates to those Loads BPA may have made after the WECC base cases were received from WECC.

- **$NITS_{Fi}$**: BPA assumes a 1-in-2 year seasonal heavy or light Load forecast, depending on the flowgate being studied. (MOD-030 R6.1.1, MOD-030 R6.2.1)
- **PTP_{Fi}** and **GF_{Fi}**: For the PTP_{Fi} and GF_{Fi} Long-Term Reservations modeled in the ETC Cases, BPA assumes the lesser of the 1-in-2 year non-coincidental seasonal peak Load forecast or firm rights to deliver power to the Load. (MOD-30 R6.3, MOD-30 R6.4, MOD-30 R6.5, MOD-30 R6.6)

Generation: BPA does not use the generation assumptions contained in the WECC base cases. Instead, BPA uses the following generation assumptions:

FCRPS: For the FCRPS resources serving $NITS_{Fi}$, PTP_{Fi}, and GF_{Fi} Long-Term Reservations, generation levels are set using a multiple-step process. For all seasons, BPA uses the following process:

- The Columbia Generating Station is assumed to be on-line at full Load in the power flow cases.

- Generation levels at the Libby, Hungry Horse, Dworshak, and Albeni Falls projects are set based on the requirements set forth in the 2000 Biological Opinion.
- In addition, the generation levels at the Willamette Valley projects[4] are set at the minimum levels seen by season.
- **90^{th} Percentile Method:** When creating heavy load ETC Cases, generation levels for all other federal hydro projects[5] are set by first determining each project's 90th percentile of historic generation by project and month. These values by project and month are then horizontally summed to produce a 'total' of each project's independent 90^{th} percentile generation. Each project's monthly 90^{th} percentile value is then divided by the total, resulting in a matrix of percentiles known as the FCRPS distribution pattern. This distribution pattern simply reflects where generation has historically occurred at federal projects. This matrix of percentiles is then multiplied by the $NITS_{Fi}$ Load obligation and GF_{Fi} contracts that have the FCRPS specified as the source, after adjusting these Demands for the portion served by Columbia Generating Station, Libby, Hungry Horse, Dworshak, Albeni Falls, and the Willamette Valley projects. The Demand of the PTP_F contracts served by each federal project is added to this result to determine the final generation level assumed for each federal hydro project. This overall method for modeling the federal resources is referred to as the "90^{th} Percentile Method."
- When creating light load ETC Cases, a ratio (consisting of load within the Northwest) of the light Load to heavy Load cases is calculated and applied to all FCRPS obligations prior to the generation assumptions and application of the 90^{th} Percentile Method.

Non-Federal Thermal Generators: Non-federal thermal generators associated with PTP_{Fi}, GF_{Fi} and $NITS_{Fi}$ Transmission Service for BPA's area and all adjacent TSP areas are set at up to the contract Demand.(MOD-30 R6.1.2, MOD-30 R6.2.2, MOD-30 R6.3, MOD-030 R6.4, MOD-030 R6.5, MOD-030 R6.6)

Wind Generators:

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[4] Willamette Valley projects include: Big Cliff, Cougar, Detroit, Dexter, Foster, Green Peter, Hills Creek, Lookout Point, Lost Creek.

[5] Federal hydro projects include: Grand Coulee, Chief Joseph, Lower Granite, Lower Monumental, Little Goose, Ice Harbor, McNary, John Day, The Dalles, Bonneville.

[6] Willamette Valley projects include: Big Cliff, Cougar, Detroit, Dexter, Foster, Green Peter, Hills Creek, Lookout Point, Lost Creek.

- **PTP_{Fi}:** Wind generators associated with PTP_{Fi} Long-Term Reservations are modeled at up to 80 percent of the wind generators' contract Demands for BPA's area and all adjacent TSP areas. (MOD-030 R6.3, MOD-030 R6.4)
- **$NITS_{Fi}$:** The Flowgate impacts of wind generators identified as designated network resources in $NITS_{Fi}$ contracts or in the NT Resources Memorandum of Agreement in BPA's area are determined on a Flowgate-by-Flowgate basis and set at the greater of the following:
  - The wind generators modeled on at the designated amount of the wind generators; or,
  - The wind generators modeled off and replaced by increasing the FCRPS generation level by the designated amount of the wind generators using the "90^{th} Percentile Method" for all seasons described on p. 44. (MOD-030 R6.1.2)

  Wind generators designated as network resources in $NITS_{Fi}$ contracts for all adjacent TSPs are modeled up to the designated amount.
- **GF_{Fi}:** BPA and all of BPA's adjacent TSPs have no GF_{Fi} contracts for wind generators. (MOD-030 R6.5, MOD-030 R6.6)

Behind the Meter Generators: Non-federal resources that do not require Transmission Service over the FCRTS and that are behind the meter are set up to levels used in BPA's process for power system planning studies. (MOD-30 R6.1.2, MOD-30 R6.2.2, MOD-30 R6.3, MOD-030 R6.4, MOD-030 R6.5, MOD-030 R6.6)

Mid-Columbia Hydro Projects: Generation levels at the non-federal Mid-Columbia hydro projects are set up to 90 percent of their historical output by season. (MOD-30 R6.1.2, MOD-30 R6.2.2, MOD-30 R6.3, MOD-030 R6.4, MOD-030 R6.5, MOD-030 R6.6)

When creating heavy load ETC Cases, if there is more generation than load plus commited exports in the case, BPA reduces the Mid-Columbia Hydro Projects by 50 percent of the excess generation and FCRPS generation by the other 50 percent of the excess generation using the "90^{th} Percentile Method" for all seasons; the exports modeled on the COI and Pacific DC Intertie in the case are reduced to match BPA's obligation for firm export. The generation reduction is done to bring generation and load into balance in order to solve the power flow model.

When creating light load ETC Cases, if there is more generation than Load in the case, BPA reduces excess generation using a merit order sequence of tiered generation groups that are assumed to be re-dispatched based on age, heat rate and past operation.

Sensitivity Studies

In calculating its base ETC_{Fi} values, BPA runs ETC Case Scenarios for two different sensitivities: the Canadian Entitlement Return (CER) obligation modeled on or off and wind resources designated to serve $NITS_{Fi}$ on or off.

For the CER Scenarios, BPA models the FCRPS generators delivering or not delivering energy to Canada in the amount specified in the Canadian Entitlement Agreement.

In the case where BPA models the FCRPS generators delivering energy to Canada, exports to Canada for the CER and the FCRPS generation level using the "90^{th} Percentile Method" for all seasons (see page 45) is increased by the amount specified in the Canadian Entitlement Agreement.

In the case where BPA models the FCRPS generators not delivering energy to Canada, exports to Canada for the CER and the FCRPS generation levels using the "90^{th} Percentile Method" for all representative seasons is reduced by the MW amount specified in the Canadian Entitlement Agreement.

For the $NITS_{Fi}$ wind resources Scenarios, see p. 44 for a description of the base ETC_{Fi} assumptions for wind generators serving $NITS_{Fi}$.

Therefore, in its base ETC_{Fi} sensitivity analysis, BPA models the following four Scenarios:

1. CER modeled on/$NITS_{Fi}$ wind modeled off
2. CER modeled on/$NITS_{Fi}$ wind modeled on
3. CER modeled off/$NITS_{Fi}$ wind modeled off
4. CER modeled off/$NITS_{Fi}$ wind modeled on

On a Flowgate-by-Flowgate basis, BPA uses the highest seasonal base ETC_{Fi} value calculated from these four Scenarios in its AFC calculations. Not all scenarios are run for all seasons or all Flowgates.

Since base ETC_{Fi} values are only produced for the representative months mentioned above, BPA derives a 12-month profile of base ETC_{Fi} values using weighted averages. The following table shows these weighted averages by month for heavy load ETC Cases.

Table 4

Weighted Average Base ETC_{Fi} Values

Month	Percentage Used	Base ETC Values Used
January	100	January
February	100	January
March	50 50	January May
April	100	May
May	100	May
June	100	June
July	100	August
August	100	August
September	75 25	August January
October	50 50	August January
November	100	January

Month	Percentage Used	Base ETC Values Used
December	100	January

For light load ETC Cases, the January ETC Case is used for all 12 months of the year.

Determining Interim ETC_{Fi} Using PTDF Analysis

To calculate the impacts for all $NITS_{Fi}$ and PTP_{Fi} reservations for BPA's area and all of BPA's adjacent TSP areas that were not modeled in the ETC Cases, BPA uses PTDF analysis on all of the Demand reserved (see "PTDF Analysis and *De Minimis*" on p. 40). PTDFs are assigned and mapped to individual bus points in the WECC base cases (refer to "Source/Sink and POR/POD Identification and Mapping" beginning on p. 40.) The sum of these impacts is referred to as the interim ETC_{Fi} value, and is added to the base ETC_{Fi} value to produce a final ETC_{Fi} value for each time period for each Flowgate. (MOD-030 R6.1, MOD-030 R6.2, MOD-030 R6.3, MOD-030 R6.4)

Calculating Firm Available Flowgate Capability (AFC_F)

When calculating AFC_F for its Flowgates for all time periods, BPA uses the following algorithm as specified in MOD-030 R8:

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + Counterflows_{Fi}$$

Where:

AFC_F is the firm Available Flowgate Capability for the Flowgate for a specific time period.

TFC is the Total Flowgate Capability of the Flowgate for that time period.

See "Establishing Total Flowgate Capability" on p. 37 for a discussion of how BPA establishes TFCs.

ETC_{Fi} is the sum of impacts of existing firm commitments for the Flowgate during that period.

In BPA's calculations, ETC_{Fi} is expressed as follows:

$$ETC_{Fi} = LRES + SRES - SADJ/ETC\ Adjustments + LETC$$

Where:

LRES is the sum of the positive impacts of PTP_{Fi}, GF_{Fi}, ROR_{Fi} and $NITS_{Fi}$ Long-Term Reservations for BPA's area, plus the sum of the positive impacts of PTP_{Fi}, GF_{Fi}, ROR_{Fi} and $NITS_{Fi}$ Long-Term Reservations for all of BPA's adjacent TSP areas, filtered to reduce or eliminate duplicate impacts from transactions that were already included in the ETC base case or that impact another Transmission Service's Providers share of Flowgate Capability.

SRES is the sum of the positive impacts of PTP_{Fi} Short-Term Reservations for BPA's area, plus the sum of the positive impacts of PTP_{Fi} Short-Term Reservations for all of BPA's adjacent TSP areas, filtered to reduce or eliminate duplicate impacts from transactions that were already included in the ETC base case or that impact another Transmission Service's Providers share of Flowgate Capability.

SADJ/ETC Adjustments is the variable used to make adjustments to ETC_{Fi} not captured in LRES or SRES. One such adjustment is applied to allow BPA to conduct deferral competitions, as required in Section 17.7 of BPA's OATT. When a deferral reservation is confirmed, BPA applies an ETC adjustment to hold out Flowgate capability for the time period deferred, starting at the latter of five months out or the service commencement date of the original reservation, to allow for a competition. At four months out, if no competition is identified, the ETC adjustment is modified to add back Flowgate capability for the fourth month out.

BPA also uses SADJ/ETC adjustments to ensure accurate accounting of ETC_{Fi}. These adjustments may be performed to account for situations such as data modeling corrections, and will be noted in the descriptions of the adjustments.

LETC is the variable used to ensure that the amount of PTP_{Fi} and GF_{Fi} capacity BPA sets aside in the LRES variable does not exceed the total PTP_{Fi} and GF_{Fi} capacity specified in the contracts. Since BPA has PTP and GF contracts that give customers the right to schedule the capacity reserved between multiple PORs and PODs, this adjustment is necessary to ensure that ETC_{Fi} is not inflated.

LETC is also used to adjust the LRES variable to match the base ETC values BPA calculates when BPA develops its ETC Cases. This adjustment is derived by comparing two values: a) the impacts of the confirmed PTP_{Fi}, GF_{Fi} and $NITS_{Fi}$ Long-Term Reservations derived from the ETC Cases and b) the impacts of the same reservations calculated using PTDF Analysis for each Flowgate. The adjustment for each Flowgate is equal to the difference of these two values. Conditional firm reservations are not included in the ETC Cases and therefore are also not included in this comparison.

As described in "PTDF Analysis and *De Minimis*" on p. 40, *de minimis* MW amounts of reservations that were not included in the ETC Cases are not accounted for when calculating ETC_{Fi} using reservations.

The following diagram illustrates how the variables used in BPA's ETC_{Fi} calculation correspond to the variables contained in the ETC_{Fi} algorithm shown in "Calculating Firm Existing Transmission Commitments" beginning on p. 42. (MOD-030 R6)

ETC_{Fi} =	**$NITS_{Fi}$**	**+**	**GF_{Fi}**	**+**	**PTP_{Fi}**	**+**	**ROR_{Fi}**
	↓		↓		↓		↓
	LRES		**LRES**		**LRES**		**LRES**
	+				**+**		
	SRES				**SRES**		
	+		**+**		**+**		**+**

	LETC		**LETC**		**LETC**		**LETC**
	-		**-**		**-**		**-**
	SADJ/ETC Adjustments		**SADJ/ETC Adjustments**		**SADJ/ETC Adjustments**		**SADJ/ETC Adjustments**

CBM_i is the impact of the Capacity Benefit Margin on the Flowgate during that period.

BPA does not maintain CBM. Therefore BPA sets CBM at zero for all of its Flowgates for all time periods.

TRM_i is the impact of the Transmission Reliability Margin on that Flowgate during that period.

BPA does not maintain TRM on its Flowgates. Therefore BPA sets TRM at zero for all of its Flowgates for all time periods.

$Postbacks_{Fi}$ are changes to AFC_F due to a change in the use of Transmission Service for that period.

Because BPA automatically recalculates ETC_{Fi} whenever there is a reduction in LRES or SRES, BPA does not use $Postbacks_{Fi}$ for calculating AFC_F on any of its Flowgates. Therefore BPA sets $Postbacks_{Fi}$ at zero for all of its Flowgates for all time periods.

$Counterflows_{Fi}$ are adjustments to AFC_F

BPA does not include confirmed Transmission reservations, expected interchange or internal flow counter to the direction of the Flowgate over and above the counterflow that is assumed in the ETC Cases. BPA's rationale is that it does not want to offer additional firm Flowgate Capability due to counterflow that may not be scheduled, as it could lead to Curtailments of Firm Transmission Service in Real-time. (MOD-01 R3.2) Therefore BPA sets the $Counterflows_{Fi}$ component at zero for all of its Flowgates for all time periods.

As a result, BPA calculates AFC_F for its Flowgates for all time periods as follows:

$$AFC_F = TFC - ETC_{Fi}$$

As described in "Determining Base ETC_{Fi}" on p. 42, counterflows are modeled in the ETC Cases. In some seasons, the amount of counterflows on particular Flowgates results in a negative ETC_{Fi} value, which, when subtracted from TFC, results in AFC_F greater than TFC.

Calculating Non-Firm Transmission Service

BPA sells six non-firm Transmission products. These products are:

1. **$NITS_{NF6i}$**. This is a non-firm Transmission product available only to Transmission Customers with NITS Agreements. It is the highest quality of Non-Firm Transmission Service in that it is the last Non-Firm Transmission Service that would be Curtailed, if necessary.

2. **PTP_{NF5i}**. This is a non-firm Transmission product available only to Transmission Customers with PTP Agreements. PTP_{NF5i} is the fifth Non-Firm Transmission Service that would be Curtailed, if necessary.

3. **PTP_{NF4i}**. This is a non-firm Transmission product available only to Transmission Customers with PTP Agreements. PTP_{NF4i} is the fourth Non-Firm Transmission Service that would be Curtailed, if necessary.

4. **PTP_{NF3i}**. This is a non-firm Transmission product available only to Transmission Customers with PTP Agreements. PTP_{NF3i} is the third Non-Firm Transmission Service that would be Curtailed, if necessary.

5. **PTP_{NF2i}**. This is a non-firm Transmission product available only to Transmission Customers with PTP Agreements. PTP_{NF2i} is the second Non-Firm Transmission Service that would be Curtailed, if necessary.

6. **PTP_{NF1i}**. This is a non-firm Transmission product available only to Transmission Customers with PTP Agreements. PTP_{NF1i} is the first Non-Firm Transmission Service that would be Curtailed, if necessary (i.e., this Transmission Service has the highest likelihood of being Curtailed).

BPA calculates ETC_{NFi} and AFC_{NF} for each of these products.

Calculating Non-Firm Existing Transmission Commitments (ETC_{NFi})

When calculating ETC_{NFi} for all time periods for a Flowgate, BPA sums the positive impacts using PTDF analysis (see "PTDF Analysis and *De Minimis*" on p. 40 for further details) as described in MOD-030 R7:

$$ETC_{NFi} = PTP_{NFi} + GF_{NFi} + NITS_{NFi} + OS_{NFi}$$

Where:

PTP_{NFi} is the impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for BPA's area. In BPA's calculations, the PTP_{NFi} component includes PTP_{NF5i}, PTP_{NF4i}, PTP_{NF3i}, PTP_{NF2i} and PTP_{NF1i}. (MOD-30 R7.1)

PTP_{NFi} also includes the impacts of any confirmed non-firm PTP Transmission Service expected to be scheduled for all of BPA's adjacent TSP areas. There are no reservations using Transmission Service from multiple TSPs, and therefore no duplicate impacts, since reservations source and sink within the same TSP's area. A separate reservation is required to acquire Transmission Service over another TSP's area. Note that BPA does not have coordination Agreements with other TSPs. (MOD-30 R7.2)

GF_{NFi} is the impact of all grandfathered non-firm obligations expected to be scheduled or expected to flow for BPA's area. BPA does not have any grandfathered non-firm Transmission Service obligations. (MOD-30 R7.3)

GF_{NFi} also includes the impacts of any grandfathered non-firm obligations expected to be scheduled or expected to flow for all of BPA's adjacent TSPs. (MOD-30 R7.4) None of BPA's adjacent TSPs have any grandfathered Non-Firm Transmission Service obligations.

Therefore BPA sets GF_{NFi} at zero for all of its Flowgates for all time periods.

$NITS_{NFi}$ is the non-firm Network Integration Transmission Service serving Load within BPA's area (i.e., secondary service), to include losses, and Load growth not otherwise included in TRM or CBM.

In BPA's calculations, this is $NITS_{NF6i}$. BPA's $NITS_{NF6i}$ calculations do not include losses or Load growth, since losses and Load growth are already set aside as firm capacity in $NITS_{Fi.}$ (MOD-30 R7.5)

$NITS_{NFi}$ also includes non-firm Network Integration Transmission Service (i.e., secondary service) for all of BPA's adjacent TSP areas. There are no transactions using Transmission Service from multiple TSPs, and therefore no duplicate impacts, since transactions source and sink within the same TSP's area. A separate reservation is required to acquire Transmission Service over another TSP's area. Note that BPA does not have coordination Agreements with other TSPs. (MOD-30 R7.6)

OS_{NFi} is the impact of other non-firm services.

BPA has no other non-firm services beyond those specified above. (MOD-30 R7.7) Therefore BPA sets OS_{NFi} at zero for all of its Flowgates for all time periods.

As a result, BPA calculates ETC_{NFi} for all time periods for its Flowgates as follows:

$$\mathbf{ETC_{NFi} = PTP_{NFi} + NITS_{NFi}}$$

As described in "PTDF Analysis and *De Minimis*" on p. 40, BPA does not account for *de minimis* MW amounts when calculating ETC_{NFi} using reservations. However, all schedules are accounted for in ETC_{NFi} regardless of their PTDF analysis impact on BPA's Flowgates when calculating ETC_{NFi} using schedules.

While BPA includes all of the components described above in ETC_{NFi}, BPA accounts for PTP_{NFi} and $NITS_{NFi}$ in its AFC calculations using different variables. For a description of the variables used see p. 56.

Calculating Non-Firm Available Flowgate Capability (AFC_{NF})

BPA uses different algorithms to calculate AFC_{NF}, ETC_{Fi} and ETC_{NFi} for two time horizons for all of its Flowgates: Real-time and beyond Real-time. The Real-time horizon begins at 10 p.m. on the pre-schedule day for the 24 hours in the next day. The ETC_{Fi} and ETC_{NFi} for the Real-Time horizon are calculated using schedules and reservations that have not yet been scheduled. The time horizon beyond Real-time includes hourly for the hours after those included in the Real-time period as well as daily and monthly calculations. The ETC_{Fi} and ETC_{NFi} for the time horizon beyond Real-time is calculated using reservations.

BPA calculates ETC_{NFi} and AFC_{NF} for the six non-firm Transmission products (described beginning on p. 50) associated with NERC Curtailment priorities as follows:

1. **AFC_{NF6}**: AFC_{NF6} is calculated for the $NITS_{NF6i}$ product. ETC_{NFi} in this equation only includes $NITS_{NF6i}$.

2. **ATC_{NF5}**: ATC_{NF5} is calculated for the PTP_{NF5i} product. ETC_{NFi} in this equation includes $NITS_{NF6i}$ and PTP_{NF5i}.

3. **ATC_{NF4}**: ATC_{NF4} is calculated for the PTP_{NF4i} product. ETC_{NFi} in this equation includes $NITS_{NF6i,}$ PTP_{NF5i} and PTP_{NF4i}.

4. **ATC_{NF3}**: ATC_{NF3} is calculated for the PTP_{NF3i} product. ETC_{NFi} in this equation includes $NITS_{NF6i,}$ $PTP_{NF5i,}$ $PTP_{NF4i,}$ and PTP_{NF3i}.

5. **AFC_{NF2}**: AFC_{NF2} is calculated for the PTP_{NF2i} product. ETC_{NFi} in this equation includes $NITS_{NF6i}$, $PTP_{NF5i,}$ $PTP_{NF4i,}$ PTP_{NF3i} and PTP_{NF2i}.

6. **AFC_{NF1}:** AFC_{NF1} is calculated for the PTP_{NF1i} product. ETC_{NFi} in this equation includes $NITS_{NF6i}$, $PTP_{NF5i,}$ $PTP_{NF4i,}$ and $PTP_{NF3i,}$ PTP_{NF2i} and PTP_{NF1i}.

BPA calculates ETC_{NFi} and AFC_{NF} for each of these products for each time period.

When calculating AFC_{NF} for its Flowgates for the two time horizons described above, BPA uses the following algorithm as specified in MOD-030 R9:

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + Counterflow_{NFi}$$

Where:

AFC_{NF} is the non-firm Available Flowgate Capability for the Flowgate for that period.

BPA calculates six AFC_{NF} values (as described above), one for each of the six non-firm Transmission products.

TFC is the Total Flowgate Capability of the Flowgate for that period.

See “Establishing Total Flowgate Capability” on p. 37, for a description of how BPA establishes TFC.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

BPA uses different algorithms to calculate ETC_{Fi} for all of its Flowgates for the time horizon beyond Real-time and the Real-time horizon.

ETC_{Fi} for the Time Horizon Beyond Real-Time

For AFC_{NF} calculations for the time horizon beyond Real-time, ETC_{Fi} is expressed as follows:

$$\mathbf{ETC_{Fi} = LRES + SRES - SADJ/ETC\ Adjustments + LETC}$$

Where:

LRES is the sum of the positive impacts of PTP_{Fi}, GF_{Fi}, ROR_{Fi} and $NITS_{Fi}$ Long-Term Reservations for BPA's area, plus the sum of the positive impacts of PTP_{Fi}, GF_{Fi}, ROR_{Fi} and $NITS_{Fi}$ Long-Term Reservations for all of BPA's adjacent TSP areas, filtered to reduce or eliminate duplicate impacts from transactions that were already included in the ETC base case or that impact another Transmission Service's Providers share of Flowgate Capability.

SRES is the sum of the positive impacts of PTP_{Fi} Short-Term Reservations for BPA's area, plus the sum of the positive impacts of PTP_{Fi} Short-Term Reservations for all of BPA's adjacent TSP areas, filtered to reduce or eliminate duplicate impacts from transactions that were already included in the ETC base case or that impact another Transmission Service's Providers share of Flowgate Capability.

SADJ/ETC Adjustments is the variable used to make adjustments to ETC_{Fi} not captured in LRES or SRES. One such adjustment is applied to allow BPA to conduct deferral competitions, as required in Section 17.7 of BPA's OATT. When a deferral reservation is confirmed, BPA applies an ETC adjustment to hold out Flowgate capability for the time period deferred, starting at the latter of five months out or the service commencement date of the original reservation, to allow for a competition. At four months out, if no competition is identified, the ETC adjustment is modified to add back Flowgate capability for the fourth month out.

BPA also uses SADJ/ETC adjustments to ensure accurate accounting of ETC_{Fi}. These adjustments may be performed to account for situations such as data modeling corrections, and will be noted in the descriptions of the adjustments.

LETC is the variable used to ensure that the amount of PTP_{Fi} and GF_{Fi} capacity BPA sets aside in the LRES variable does not exceed the total PTP_{Fi} and GF_{Fi} capacity specified in the contracts. Since BPA has PTP and GF contracts that give customers the right to schedule the capacity reserved between multiple PORs and PODs, this adjustment is necessary to ensure that ETC_{Fi} is not inflated.

LETC is also used to adjust the LRES variable to match the base ETC values BPA calculates when BPA develops its ETC Cases. This adjustment is derived by comparing two values: a) the impacts of the PTP_{Fi}, GF_{Fi} and $NITS_{Fi}$ Long-Term Reservations derived from the ETC Cases and b) the impacts of the same reservations calculated using PTDF Analysis for each Flowgate. The adjustment for each Flowgate is equal to the difference of these two values. Conditional firm reservations are not included in the ETC Cases and therefore are also not included in this comparison.

As described in “PTDF Analysis and *De Minimis*” on p. 40, *de minimis* MW amounts of reservations that were not included in the ETC Cases are not accounted for in ETC_{Fi}.

The following diagram illustrates how the variables used in BPA’s ETC_{Fi} calculation correspond to the variables contained in the ETC_{Fi} algorithm shown in “Calculating Firm Existing Transmission Commitments” beginning on p. 42.

ETC_{Fi} =	**$NITS_{Fi}$**	**+**	**GF_{Fi}**	**+**	**PTP_{Fi}**	**+**	**ROR_{Fi}**
	↓		↓		↓		↓
	LRES		**LRES**		**LRES**		**LRES**
	+				**+**		
	SRES				**SRES**		
	+		**+**				**+**
	LETC		**LETC**				**LETC**
	-		**-**		**-**		**-**
	SADJ/ETC Adjustments		**SADJ/ETC Adjustments**		**SADJ/ETC Adjustments**		**SADJ/ETC Adjustments**

ETC_{Fi} for the Real-Time Horizon

For AFC_{NF} calculations in the Real-time horizon, ETC_{Fi} is expressed as follows:

$$ETC_{Fi} = SCH^{+}_{7} + ASC^{+}_{7} + RETC$$

Where:

SCH^{+}_{7} is the sum of the positive impacts of schedules referenced to confirmed PTP_{Fi}, GF_{Fi} and $NITS_{Fi}$ reservations for BPA’s area, plus the sum of the positive impacts of PTP_{Fi}, GF_{Fi} and $NITS_{Fi}$ schedules for all of BPA’s adjacent TSP areas. (MOD-030 R7.2)

ASC^{+}_{7} is the sum of the positive impacts of dynamic schedules that reference confirmed PTP_{Fi}, GF_{Fi} and $NITS_{Fi}$ reservations for BPA’s area, plus the sum of the positive impacts of dynamic PTP_{Fi}, GF_{Fi} and $NITS_{Fi}$ schedules for all of BPA’s adjacent TSP areas.

RETC is the sum of the impacts of unscheduled $NITS_{Fi}$ that has a PTDF Analysis impact of equal to or greater than ten percent for all of BPA's adjacent TSP areas.

The following diagram illustrates how the variables used in BPA's ETC_{Fi} calculation correspond to the variables contained in the ETC_{Fi} algorithm shown in "Calculating Firm Existing Transmission Commitments" beginning on p. 42. ROR_{Fi} is not included in ETC_{FI} for the Real-Time Horizon because ROR_{Fi} is not relevant for this time period.

ETC_{Fi} =	**$NITS_{Fi}$**	**+**	**GF_{Fi}**	**+**	**PTP_{Fi}**
	$\downarrow$		$\downarrow$		$\downarrow$
	SCH^{+}_{7}		SCH^{+}_{7}		SCH^{+}_{7}
	+		**+**		**+**
	ASC^{+}_{7}		ASC^{+}_{7}		ASC^{+}_{7}
	+				
	RETC				

ETC_{NFi} is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

BPA uses different algorithms to calculate ETC_{NFi} for all of its Flowgates for the time horizon beyond Real-time and the Real-time horizon.

ETC_{NFi} for the Time Horizon Beyond Real-time

For AFC_{NF} calculations in the time horizon beyond Real-time, ETC_{NFi} is expressed as follows:

$$\mathbf{ETC_{NFi} = RRES_{NF}}$$

Where:

$RRES_{NF}$ is the sum of the positive impacts of all confirmed PTP_{NF5i}, PTP_{NF4i}, PTP_{NF3i}, PTP_{NF2i}, PTP_{NF1i} and $NITS_{NF6i}$ reservations for BPA's area, plus the sum of the positive impacts of all confirmed PTP_{NFi} and $NITS_{NFi}$ reservations for all of BPA's adjacent TSP areas.

As described in "PTDF Analysis and *De Minimis*" on p. 40, *de minimis* MW amounts are not accounted for in ETC_{NFi} when using reservations.

The following diagram explains how the variables used in BPA's ETC_{NFi} calculation correspond to the variables contained in the ETC_{NFi} algorithm shown in "Calculating Non-Firm Existing Transmission Commitments" beginning on p. 51.

ETC_{NFi} =	**$NITS_{NFi}$**	**+**	**PTP_{NFi}**
	$\downarrow$		$\downarrow$
	$RRES_{NF}$		$RRES_{NF}$

ETC_{NFi} for the Real-time Horizon

For AFC_{NF} calculations in the Real-time horizon, ETC_{NFi} is expressed as follows:

$$ETC_{NFi} = SCH^{+}_{6,5,4,3,2,1} + ASC^{+}_{6,5,4,3,2,1}$$

Where:

$SCH^{+}_{6,5,4,3,2,1}$ is the sum of the positive impacts of schedules referenced to confirmed PTP_{NF2i}, PTP_{NF1i} and $NITS_{NF6i}$ reservations for BPA's area, plus the sum of the positive impacts of PTP_{NFi} and $NITS_{NFi}$ schedules for all of BPA's adjacent TSP areas.

$ASC^{+}_{6,5,4,3,2,1}$ is the sum of positive impacts of dynamic schedules referenced to confirmed PTP_{NF2i}, PTP_{NF1i} and $NITS_{NF6i}$ reservations for BPA's area, plus the sum of the positive impacts of dynamic PTP_{NFi}, GF_{NFi} and $NITS_{NFi}$ schedules for all of BPA's adjacent TSP areas.

The following diagram illustrates how the variables used in BPA's ETC_{Fi} calculation correspond to the variables contained in the ETC_{Fi} algorithm shown in "Calculating Non-Firm Existing Transmission Commitments" beginning on p. 51.

ETC_{NFi} =	**$NITS_{NFi}$**	**+**	**PTP_{NFi}**
	↓		↓
	$SCH^{+}_{6,5,4,3,2,1}$		$SCH^{+}_{6,5,4,3,2,1}$
	+		**+**
	$ASC^{+}_{6,5,4,3,2,1}$		$ASC^{+}_{6,5,4,3,2,1}$

CBM_{Si} is the impact of any schedules during that period using Capacity Benefit Margin.

BPA does not maintain CBM. Therefore BPA sets CBM_{Si} at zero for all of its Flowgates for all time periods.

TRM_{Ui} is the impact on the Flowgate of the Transmission Reliability Margin for the Flowgate that has not been released for sale (unreleased) as non-firm capacity during that period.

BPA does not maintain TRM on its Flowgates. Therefore BPA sets TRM_{Ui} at zero for all of its Flowgates for all time periods.

$Postbacks_{NFi}$ are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period.

Because BPA automatically recalculates ETC_{Fi} and ETC_{NFi} whenever there is a reduction in LRES, SRES, or RRES, BPA does not use $Postbacks_{NFi}$ for calculating AFC_{NF} for any of its Flowgates in the time horizon beyond Real-time.

BPA also does not use $Postbacks_{NFi}$ for any of its Flowgates for the Real-time horizon.

Therefore BPA sets $Postbacks_{NFi}$ at zero for all of its Flowgates for the time horizon beyond Real-time and the Real-time horizon.

$Counterflows_{NFi}$ are adjustments to non-firm Available Flowgate Capability.

Counterflows resulting from firm and non-firm Transmission schedules, excluding dynamic schedules, are added back to AFC_{NF} in the $Counterflows_{NFi}$ component.

$Counterflows_{NFi}$ is the sum of the negative impacts of schedules referenced to confirmed firm and non-firm reservations in BPA's area, plus the sum of the negative impacts of schedules for all of BPA's adjacent TSP areas. In BPA's calculations, $Counterflows_{NFi}$ is expressed as $SCH^{-}_{7,6,5,4,3,2,1}$.

As a result BPA calculates AFC_{NF} for its Flowgates for all time periods as follows:

$$\mathbf{AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} + Counterflows_{NFi}}$$

As described in "Determining Base ETC_{Fi}" on p. 42, counterflows are modeled in the ETC Cases used to determine ETC_{Fi}. In some cases, the amount of counterflows on particular Flowgates result in a negative ETC_{Fi} value, which, when subtracted from TFC, results in AFC_{NF} greater than TFC. In other cases, the amount of $Counterflows_{NFi}$ exceeds the sum of the ETC_{Fi} and ETC_{NFi}, which, when added to TFC, also results in AFC_{NF} greater than TFC.

Converting AFC to ATC

BPA does not convert Flowgate AFCs to ATCs. (MOD-030 R11)

IX. Data Sources and Recipients

BPA receives data for use in its ATC and AFC calculations, and provides data for use in calculating transfer and Flowgate capabilities through the WECC base case process described beginning on p. 5. BPA also directly receives and provides data, such as outage information and specific Transmission commitments, from and to the following Transmission Service Providers and Transmission Operators: (MOD-001 R3.3, R3.4)

- Avista Corporation
- BC Hydro
- California Independent System Operator
- City of Tacoma, Department of Public Utilities, Light Division
- Eugene Water and Electric Board
- Fortis BC
- Idaho Power Company
- Los Angeles Department of Water and Power
- Nevada Power
- NorthWestern Energy
- Pacific Gas & Electric
- PacifiCorp (PAC)
- Pend Oreille County Public Utility District No. 1
- Portland General Electric
- Public Utility District No. 1 of Chelan County
- Public Utility District No. 1 of Clark County
- Public Utility District No. 1 of Douglas County
- Public Utility District No. 2 of Grant County, Washington
- Public Utility District No. 1 of Snohomish County
- Puget Sound Energy, Inc.
- Sacramento Municipal Utility District
- Seattle City Light
- Sierra Pacific Power Company
- Southern California Edison
- Transmission Agency of Northern California
- Western Area Power Administration – Sierra Nevada Region
- California Independent System Operator

X. Responding to Data Requests

Upon official request from any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for any data from the list below, solely for use in the requestor's ATC or AFC calculations, BPA will begin to make the data available within 30 calendar days of receiving the request.

- Expected generation and Transmission outages, additions, and retirements
- Load forecasts
- Unit commitments and order of dispatch, to include all designated resources (BPA does not have resources that are committed or have the legal obligation to run)
- Firm NITS and non-firm NITS (i.e. Secondary Service)
- Firm and non-firm Transmission reservations
- Grandfathered obligations
- Firm roll-over rights
- Any firm and non-firm adjustments applied by BPA to reflect parallel path impacts
- Power flow models and underlying assumptions
- Contingencies, provided in one or more of the following formats:
    - A list of Elements
    - A list of Flowgates
    - A set of selection criteria that can be applied to the WECC base cases used by BPA
- Facility Ratings
- Any other service that impact ETCs
- Values of CBM and TRM for all ATC Paths and Flowgates
- Values of TFC and AFC for all Flowgates
- Values of TTC and ATC for all ATC Paths
- Source and sink identification and mapping to the WECC base cases

BPA will make this data available on the schedule specified by the requestor (but no more frequently than once per hour, unless mutually agreed to by the requestor and Bonneville).

For a Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator to officially request data to use in ATC or AFC calculations, the requestor must fill out the **Data Request Form** (MOD-001-1 R9) found on BPA's website http://transmission.bpa.gov/business/atc_methodology/. The completed request form must be sent to nercatcstandards@bpa.gov with **Data request Form** (MOD-001-1 R9) in the subject line. (MOD-001 R9)

XI. ATCID Revisions

BPA will notify the following entities before implementing a new or revised ATCID and make its current ATCID available. (MOD-001 R4, R5)

Entity	Planning Coordinator Associated with/Adjacent to BPA's area	Reliability Coordinator Associated with/Adjacent to BPA's area	Transmission Operator Associated with/Adjacent to BPA's Area	Transmission Service Provider Adjacent to BPA's Area
Avista Corporation	X		X	X
BC Hydro	X		X	X
California Independent System Operator	X		X	X
City of Tacoma, Dept. of Public Utilities, Light Division	X		X	X
Eugene Water & Electric Board			X	
Fortis BC	X		X	X
Idaho Power Co.	X		X	X
Los Angeles Department of Water & Power	X		X	X
Nevada Power			X	X
NorthWestern Energy	X		X	X
PacifiCorp	X		X	X
Pacific Gas and Electric Co.			X	
Pend Oreille County PUD No. 1			X	
Portland General Electric	X		X	X
PUD No. 1 Chelan County			X	
PUD No. 1 Clark County			X	
PUD No. 1 Douglas County			X	
PUD No. 1 Snohomish County			X	
PUD No. 2 Grant County, Washington	X		X	
Puget Sound Energy, Inc.	X		X	X
Sacramento Municipal Utility District	X		X	X

Entity	Planning Coordinator Associated with/Adjacent to BPA's area	Reliability Coordinator Associated with/Adjacent to BPA's area	Transmission Operator Associated with/Adjacent to BPA's Area	Transmission Service Provider Adjacent to BPA's Area
Seattle City Light	**X**		**X**	
Sierra Pacific Power Co.	**X**		**X**	**X**
Southern CAL Edison (Trans & Dist Bus Unit)			**X**	
Transmission Agency of Northern California				**X**
Western Area Power Admin. Sierra Nevada Region	**X**		**X**	**X**
Western Electric Coordination Council		**X**		

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XII. Version History

ATCID Revision History			
Version	**Date Revised**	**Description of Changes**	**Prepared by**
1.0	3/30/2011	BPA ATCID FINAL	S Long L Trolese C Etheridge
2.0	5/11/2011	P.31 Table 2 BPA Flowgates: Corrected the definition of the West of McNary Flowgate by replacing McNary – Horse Heaven 230 kV line with Harvalum – Big Eddy #1 230 kV line in the West of McNary Flowgate Transmission Line Components	L Trolese
3.0	08/11/2011	P. 7 line 114: Revised frequency of hourly calculations from at least three times per hour to at least once per hour. P. 12-13 Table 1 BPA Paths: Added Montana-Northwest to the Path Name; added Garrison 500 kV 1 and 2 to the Transmission Line Components of the West of Garrison E>W and W>E Paths and revised the Montana Intertie Transmission Line Component from Broadview – Garrison 500 kV 1 and 2 to Townsend-Garrison 500 kV 1 and 2 to be effective October 1, 2011. P. 17 lines 395-397: Revised sentence to include Montana Intertie as an ATC Path that is limited by contract. P. 18 lines 440-445: Revised paragraph to include Montana Intertie as an ATC Path where another TOP sets the TTC. P. 19 line 483-486 and P. 40 line 1102: Added forecasted network resources to be included in Network Integration Transmission Service P. 20 line 517: corrected reference from ETC to ATC_{NF}. P. 20 line 531; P. 22 ETC_F variable diagram, P. 25 line 669, P. 26 ETC_F variable diagram, P. 47 line 1324, P. 49 ETC_F variable diagram, P. 53 line 1493 and P. 54 ETC_F variable diagram: Corrected ETC_F formula to subtract SADJ/ETC Adjustments instead of	L Trolese

ATCID Revision History			
		add it. P. 27 lines 724-726 and P. 55 lines 1549-1551: Updated reason for why ROR_F is not included in the real-time horizon. P. 29 line 789: Deleted "implemented" from which schedules impact counterflows. P. 30 lines 798-800: Added a note describing the variable RADJ/Congestion Management and how it impacts ATC calculations. P. 44: Corrected footnote 7 to align it with the reference. P. 47: Deleted language referring to including adjacent TSP reservations in interim ETC_{Fi}. P. 53 lines 1517-1521: Added paragraph describing LETC that was mistakenly left out in Version 1.0 and 2.0. P. 57 line 1604: Deleted "confirmed" from which schedules impact counterflows. P. 58: Replaced table delineating the NERC registered functions of the entities with a bulleted list of the entities. Appendix A: Updated List of Contracts and Specific Paths with Shared Ownership to indicate the Colstrip Project on the Montana Intertie Path will no longer be represented as an allocation agreement after October 1, 2011. Appendix C: Updated the SOL Methodology. Appendix D: Updated BPA's NITS, GF, and PTP Agreements to include the Colstrip Project and other contracts that have been added since February 3, 2011.	
4.0	9/30/2011	P. 27 lines 720 – 722 and ETC_F variable diagram: added new use for RADJ/ETC Adjustments variable.	L Trolese
5.0	10/20/2011	P. 39 lines 1068-1070, P. 40 lines 1077-1079 and lines 1087-1089: Removed language referring to the month of August. P. 40 lines 1103-1114, P. 41 lines 1118-1128 and P.	L Trolese

ATCID Revision History			
		48 lines 1325-1331: added paragraph describing how BPA accounts for the impacts of its adjacent TSP firm NITS and PTP Transmission Service.	
6.0	11/1/2011	P.31 Table 2 BPA Flowgates: Added the McNary – John Day #2 500 kV line to the West of McNary Flowgate definition. Appendix C: Updated the SOL Methodology.	L Beckman
7.0	11/10/2011	P. 40 line 1103 and P.41 line 1118: Changed effective date from November 8th to no later than November 15, 2011 for incorporating adjacent TSP TSRs into AFC calculations.	L Beckman
8.0	2/3/2012	P. 35 line 907: Added paragraph describing how BPA prepares for the addition of a flowgate.	L Beckman
9.0	2/13/2012	P. 5, P. 22, P. 29: Defined BPA's TRM practice for the Northern Intertie S>N Path. P. 20 line 528 and P. 23 line 597: Replaced NI Holdout in the ATC_F formula with TRM.	L Beckman
10.0	2/14/2012	P.30-31 Table 2 BPA Flowgates: Corrected the following flowgate definitions: South of Allston Flowgate: replaced Astoria-Seaside 115kV; and Lewis & Clark-Astoria Tap 115kV line with Astoria-Seaside 115kV; and Clatsop 230/115kV line in the South of Allston Flowgate Transmission Line Components. North of John Day Flowgate: replaced Wautoma-John Day 500kV line with Wautoma-Rock Creek 500kV line in the North of John Day Flowgate Transmission Line Components. Cross Cascades North Flowgate: Added the Anderson Canyon-Beverly Park 115 kV line to the Cross Cascades North Flowgate Transmission Line Components. Cross Cascades South Flowgate: replaced Hanford-Ostrander 500kV line with Wautoma-Ostrander 500kV line, replaced McNary-Santiam 230kV line with Jones Canyon-Santiam 230kV line, replaced Parkdale-Troutdale 230kV with Big Eddy-Troutdale 230kV, and added Bethel – Round Butte 230 kV line in the Cross Cascades South Flowgate Transmission Line Components. West of McNary Flowgate: replaced McNary-Santiam 230kV line with Jones Canyon-Santiam 230kV line in the West of McNary Flowgate Transmission Line Components.	L Beckman

ATCID Revision History			
11.0	2/22/2012	P. 8 line 166: Removed reference to Northwest Power Pool (NWPP) Outage Coordination Processes, dated 01/29/09.	L Beckman
12.0	3/1/2012	P. 32 Table 2 BPA Flowgates: Added the West of John Day Flowgate and Transmission Line Components. P. 32 Figure 3 BPA Network Flowgate Map: Added the West of John Day Flowgate.	L Beckman
13.0	3/27/2012	P. 31 Table 2 BPA Flowgates: Removed the Anderson Canyon-Beverly Park 115 kV line from the Cross Cascades North Flowgate Transmission Line Components. P. 4 line 52: Moved MOD 008-01 to the Methodologies Selected section.	L Beckman
14.0	4/11/2012	Appendix A: Updated Portland General Electric's Intertie Agreements to reflect the termination of the AC/DC Exchange Agreement that will be effective on 7/1/2012.	L Beckman
15.0	5/15/2012	P. 38 lines 1013-1015, P. 41 lines 1107-1115, P. 46 lines 1282-1289, P. 50 lines 1402-1407 and P. 50 lines 1422-1427: Moved language regarding the PTDF Analysis impact and percentage used in the Western Interconnection-wide Congestion Management Procedure. P. 40 lines 1084-1093: Added generation estimates as the source of the PTDF weightings. P. 42 lines 1157-1159 and P. 51 lines 1433-1436: Added description of how BPA accounts for schedules in ETC_{Fi}. P. 44-45: Removed the definition of and all reference to the "94th Percentile Method". P. 47 lines 1305-1315 and P. 52 lines 1476-1486: clarified that LRES and SRES include reservations for all of BPA's adjacent TSP areas, filtered to reduce duplicates.	L Beckman L Trolese
16.0	6/27/2012	P. 40 lines 1084-1086: changed sentence to describe that BPA is grouping the generators for all of its adjacent BAAs instead of just a subset.	L Trolese
17.0	8/15/2012	P. 31 Table 2 BPA Flowgates: Added outage conditions flowgate definition for Raver-Paul (N>S). P. 29-30 lines 774,787,799: Replaced RADJ variable descriptions with RADJ/ETC.	L Beckman

ATCID Revision History			
18.0	9/20/2012	P. 12 line 299 Table 1 BPA Paths: Removed Transmission Line Components and RAS. P. 23-28 lines 599-607, 633, 750 and 752: Added new Non-firm products to formulas used for calculating Non-firm ETC and Non-firm ATC. P. 50-56 lines 1403-1411, 1428, 1479-1484 and 1604: Added new Non-firm products to formulas used for calculating Non-firm ETC and Non-firm AFC. Appendix C: Updated the SOL Methodology.	L Beckman
19.0	10/18/2012	P. 48 and 53, lines 1334 and 1513: Removed language on accounting for Conditional Firm products in the ETC Adjustment.	L Beckman
20.0	10/24/2012	P. 32 Table 2 BPA Flowgates: Added the South of Boundary Flowgate and Transmission Line Components. P. 33 Figure 3 BPA Network Flowgate Map: Added the South of Boundary Flowgate.	L Beckman
21.0	11/14/2012	P. 8, lines 159-167: Updated BPA's allocation processes for the Columbia Injection (N>S) and Wanapum Injection (N>S) flowgates. P. 31 Table 2 BPA Flowgates: Replaced Bettas Road - Covington #1 230kV with Bettas Road - Covington #1 230kV in the Cross Cascades North Flowgate Transmission Line Components. P. 31-33 Table 2 BPA Flowgates: Added the North of Hanford (S>N), South of Allston (S>N), Columbia Injection (N>S), Wanapum Injection (N>S) and West of Lower Monumental (E>W) Flowgates in Transmission Line Components, effective Nov. 30, 2012. P. 45 and 46, lines 1245-1248, 1286-1288 and 1318: Added documentation describing ETC calculation practices for light load ETC Cases. P. 55 and 56, lines 1564, 1574-1576 and 1580: Added RETC variable and definition to calculation formula for ETCFi for the Real-Time Horizon.	L Beckman
22.0	1/31/2013	Appendix A: Updated Seattle City Light's PNW AC Intertie Ownership Agreement to reflect shared ownership, effective 1/31/13.	L Wickizer
23.0	1/31/2013	P. 5 line 61, P. 22 line 579, P. 23 lines 594-596, P. 29 line 786: Removed BPA's TRM practice for the	L Wickizer

ATCID Revision History			
		Northern Intertie S>N Path, effective Feb. 13, 2013. P. 31-33 Table 2 BPA Flowgates: Added the North of Echo Lake (S>N) and South of Custer (N>S) Flowgates and removed the Monroe-Echo Lake Flowgate in Transmission Line Components, effective Feb. 13, 2013. P. 32 Table 2 BPA Flowgates: Added John Day – Marion No. 1 500kV in the West of John Day Flowgate Transmission Line Components, effective Feb. 13, 2013. P.33 Figure 3 BPA Network Flowgate Map: Updated location of the North of Echo Lake (S>N) and South of Custer (N>S) Flowgates.	
24.0	2/12/2013	P. 5 lines 52-57, P. 22 lines 581-584, P. 23 lines 597-601, P. 29 lines 788-793, P. 30 lines 826-830: Added BPA's updated TRM practice for the Northern Intertie Path.	L Wickizer

Appendix A

List of Contracts and Specific Paths with Shared Ownership

List of Contracts and Specific Paths with Shared Ownership

PATH NAME	DIRECTION	CONTRACT DESCRIPTION	CONTRACT NUMBER	CONTRACT PARTY
SOUTH OF ALLSTON	N>S	ALLOCATION AGREEMENT - SOUTH OF ALLSTON TRANSMISSION PATH	06TX-12300	PACIFICORP
				PORTLAND GENERAL ELECTRIC
WEST OF CASCADES - NORTH	E>W	WHEELING AGREEMENT	DE-MS79-88BP92521	PUGET SOUND ENERGY
CALIFORNIA OREGON INTERTIE (COI)	N>S S>N	INTERTIE AGREEMENT AC/DC Exchange Agreement Terminated Effective: 7/1/2012	DE-MS79-87BP92340	PORTLAND GENERAL ELECTRIC
		AC INTERTIE AGREEMENT	DE-MS79-94BP94332	PACIFICORP
		PNW AC INTERTIE CAPACITY OWNERSHIP	DE-MS79-95BP94628	PACIFICORP
		PNW AC INTERTIE CAPACITY OWNERSHIP	DE-MS79-94BP94521	PUGET SOUND ENERGY
		PNW AC INTERTIE CAPACITY OWNERSHIP	13ZZ-15826 (formerly DE-MS79-94BP94522)	SEATTLE CITY LIGHT, EDF TRADING NORTH AMERICA LLC, and SOUTHERN CALIFORNIA EDISON COMPANY (Effective 1/31/2013)
		PNW AC INTERTIE CAPACITY OWNERSHIP	DE-MS79-94BP94523	POWER RESOURCES COOPERATIVE
		PNW AC INTERTIE CAPACITY OWNERSHIP	DE-MS79-94BP94524	TACOMA POWER
		PNW AC INTERTIE CAPACITY OWNERSHIP	DE-MS79-94BP94525	SNOHOMISH COUNTY PUD
		CONSENT AGREEMENT	10TX-15107	SEATTLE CITY LIGHT
PACIFIC DC INTERTIE (PDCI)	N>S S>N	INTERTIE AGREEMENT AC/DC Exchange Agreement Terminated Effective: 7/1/2012	DE-MS79-87BP92340	PORTLAND GENERAL ELECTRIC
NORTHERN INTERTIE	N>S S>N	WESTSIDE NORTHERN INTERTIE & AREA TRANSMISSION	DE-MS79-95BP93081	PUGET SOUND ENERGY
WEST OF GARRISON	E>W	ALLOCATION WEST OF GARRISON	DE-MS79-88BP92522	AVISTA CORPORATION
		CAPACITY MANAGEMENT PROCEDURES AGREEMENT	09TX-14013	AVISTA CORPORATION
	W>E	ALLOCATION WEST OF GARRISON	DE-MS79-88BP92522	AVISTA CORPORATION
		CAPACITY MANAGEMENT PROCEDURES AGREEMENT	09TX-14013	AVISTA CORPORATION
WEST OF HATWAI	E>W	SETTLEMENT	AV-TR02-0151	AVISTA CORPORATION

Appendix B

Significant Equipment Operating Bulletin 19

This document is Official Use Only and will not be provided as part of this ATCID.

Appendix C

BPA Technical Operations

System Operating Limits Methodology for the Operations Horizon

BPA Technical Operations

System Operating Limits Methodology for the Operations Horizon

1. Determining System Operating Limits (SOLs) – BPA monitored paths will be screened using the following methodologies as applicable to determine SOLs. The most limiting methodology will determine the SOL. All monitored facilities shall be within their thermal, voltage, and stability limits.

   For the Study Model, BPA starts with a complete and approved WECC Operating Base Case. The Study Model is adjusted for the anticipated transmission system configuration (including planned outages), generation dispatch and load level for the study area of interest and the corresponding study period.

   a. **Studied Contingencies** – Credible unplanned outages need to be studied to ensure that system reliability is maintained in the event that these contingencies occur.
      - Referencing WECC FAC 011-2, BPA has determined that the following contingencies on the BES need to be screened for the establishment of SOLs:
        - All N-1 generators, transmission lines and transformers
        - All common tower circuits that are greater than 5 spans out of a substation.
        - Any adjacent circuit pair in a common corridor greater than 5 spans out of a substation, unless the outage frequency is determined to be less than one in thirty years. (If thirty years of outage history can be shown to have no common mode outages for the pair, it may be ignored from operating studies)
        - All 500kV breaker failures as necessary for ensuring main grid stability.
        - Pacific DC Intertie (PDCI) bi-pole loss
        - Any common mode outage of two generating units that are connected to the same switchyard or non-common mode double outage of any nuclear power generating plant. (No voltage margin is necessary when determining voltage stability limits for these contingencies)

   b. **Thermal Limits** - Paths are screened for limitations caused by thermal equipment limits following an outage condition using the following methodology:
      - The powerflow base case will be checked for:
        - Accurate system topology

  - Reasonable load and generation levels for the time period of the study
  - Appropriate voltage profile
  - Load versus temperature analysis may be used to develop base cases for different operating conditions.
- The contingencies that need to be considered for determining thermal limits are described in Section a: "Studied Contingencies".
- If an unplanned outage occurs on a thermally limited path, operators have 30 minutes to establish a new SOL based upon these new system conditions and to protect for the next worst contingency.
- Time versus temperature analysis may be used to maximize limits, ensuring that the maximum operating temperature on the overloaded facility is not reached within 20 minutes.
  - This allows adequate time for manual dispatcher response to reduce system loading problems through a planned procedure.
- Generation variations can be taken into account provided the generator output can be monitored.
- Limiting Elements within Contingencies with Outage Transfer Distribution Factors (OTDF) below 3.0 % may be ignored.
  - This allows the removal of limiting elements that are relatively insensitive to power transfers on a path for a contingency.
- Remedial Action Schemes (RAS), if applicable, are modeled, including:
  - Generation dropping
  - Shunt reactive device switching
  - Series capacitor switching
  - Phase shifter adjustment
  - Line and/or load tripping
  - DC line ramping or tripping
  - Area separation schemes
- Outages must meet the Transmission Systems Standards - Normal and Contingency Conditions as defined in the NERC/WECC Planning Standards.

c. **Voltage Stability Limits** – Paths are screened for voltage stability limits if previous studies have shown the path is sensitive to voltage stability problems or the path has not been previously studied, using the following methodology:

- There are two approaches for voltage stability studies:
  1. <u>If the path is prone to voltage stability limitations:</u>
     - The full contingency list (as defined in Section a: "Studied Contingencies") is used for seasonal studies.
     - For outage studies (planned or unplanned) a reduced contingency list of the worst performing contingencies may be used to reduce study time.

  2. <u>If the path is typically thermal limited</u>, voltage stability screening will only be conducted when there are major transmission changes that could impact the results.

- RAS if applicable are modeled, including:

- Generation dropping
- Shunt reactive device switching
- Series capacitor insertion
- Phase shifter adjustment
- Line and/or load tripping
- DC line ramping or tripping
- Area separation schemes

- BPA follows the WECC voltage stability analysis documented in the "Guide to WECC/NERC Planning standards I.D.: Voltage Support and Reactive Power" to ensure positive reactive margin is maintained for all of the contingencies studied.
- If an unplanned outage occurs on a voltage stability limited path, operators have 30 minutes to establish a new SOL based upon these new system conditions and to protect for the next worst contingency.
- BPA applies the following additional margin for determining the SOL on a voltage stability limited path:
  - 5.0% for an N-1 contingency
  - 2.5% for an N-2 contingency
  - 0.0% for an N-2 of any common mode outage of two generating units that are connected to the same switchyard or non-common mode double outage of any nuclear power generating plant

d. **Transient Stability Limits** - Paths are screened for transient stability limits if previous studies have shown the path is sensitive to transient stability problems or the path has not been studied before, using the following methodology:

- There are two approaches for transient stability studies:

  1. <u>If the path is prone to transient stability limitations</u>

     - The contingency list used for transient stability studies is a subset of the contingencies used for thermal and voltage stability studies. They are chosen based on the following criteria:
       - Any contingency that would set the SOL based on voltage stability criteria.
       - Additional contingencies based on historical system response, previous study responses or the judgment of the study engineer.

  2. <u>If the path is typically thermal or voltage stability limited</u>

     - Transient stability screening will only be conducted when there are major transmission changes that could impact the results.

- Remedial Action Schemes (RAS) if applicable are modeled, including:
  - Generation dropping
  - Shunt reactive device switching
  - Resistive brake insertion
  - Series capacitor insertion
  - Line and/or load tripping

    - DC line ramping or tripping
    - Area separation schemes
- Each contingency is run for a 20-40 second simulation.
- If an unplanned outage occurs on a transient stability limited path, operators have 30 minutes to establish a new SOL based upon these new system conditions and to protect for the next worst contingency.
- Results are compared to the criteria in the WECC Disturbance Performance Table as defined in the NERC/WECC Planning Standards for acceptability.
    - Acceptability is based on but not limited to:
        - Maximum first swing voltage dip and duration
        - Low frequency dip, and
        - System damping

e. Overall Performance Criteria – The establishment of all SOLs need to meet these minimum criteria
- All facilities are operating within their acceptable Post-Contingency thermal, frequency and voltage ratings.
- Cascading outages do not occur
- Uncontrolled system separation does not occur.
- The system demonstrates transient, dynamic and voltage stability.
- Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding) is allowed. The planned removal of certain generators, and/or the curtailment of contracted firm electric power transfers may be necessary to maintain the overall security of the interconnected transmission system.
- Interruption of firm transfer, load or system reconfiguration is permitted through manual or automatic control or protection actions.
- To prepare for the next contingency, system adjustments are permitted, including changes to generation, load and the transmission system topology when determining limits.
- Any common mode outage of two generating units that are connected to the same switchyard or non-common mode double outage of any nuclear power generating plant needs meet the following
    - Cascading outages do not occur.

NERC Definitions

System Operating Limit (SOL) – The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

/s/ John G. Anasis________________

John G. Anasis

Electrical Engineer

Concur:

/s/ Margaret I. Albright_____________ August 27, 2012_________

Margaret I. Albright Date

Manager, Technical Operations

Version History

Version	Issue Date	Action/Changes	Prepared By	Reviewed By	Approved By Signature	Date Signed
1.0	8/24/09	Updated date of document and added language to clarify consistency with RC SOL Methodology	Signed MRV Mike Viles		Signed EGE *Edison G. Elizeh*	8/24/09
1.1	11/02/09	Revised Document title and 2nd bullet under 1.a.	Mike Viles		Edison G. Elizeh	
1.2	11/14/09	Added language to address study model used	Mike Viles		/s/ Edison G. Elizeh	11/16/09
2.0	09/08/10	Updated document to reflect studied contingencies, margins, and requirements for establishing SOLs.	Mike Viles		/s/ Edison G. Elizeh	09/08/10
2.1	07/18/11	Updated document to reflect SOL 30 minute threshold	/s/ James O'Brien		/s/ John S. Kerr for Melvin Rodrigues	07/18/10
2.2	09/30/11	Removed "transformer" from 1.a. 4th sub-bullet	/s/		/s/	

			James O'Brien		Melvin Rodrigues	10/3/11
2.3	10/20/11	Removed "A double pole loss of the PDCI is considered an N-1 contingency" from 1.a.1st sub-bullet. Added " PDCI bi-pole loss as 1.a. 5th sub-bullet.	/s/ James O'Brien		/s/ Melvin Rodrigues	10/20/11
2.4	08/23/12	Section 1, removed "WECC does not have IROLS so they are not identified as a subset of SOL's in this methodology."	John Anasis		Margaret I. Albright	

JGAnasis:kjh:2409:08/23/2012

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Appendix D

BPA's NITS, GF and PTP Agreements as of August 15, 2011

List of BPA's NITS, GF, and PTP Agreements as of August 15, 2011

NETWORK INTEGRATION TRANSMISSION SERVICE (NT)

ACTIVE BPA TRANSMISSION SERVICE AGREEMENTS AS OF AUGUST 15, 2011			
NETWORK INTEGRATION TRANSMISSION SERVICE (NT)			
Contract Number	Customer	Effective	Execution
01TX-10436	ALDER MUTUAL LIGHT COMPANY	10/1/2001	5/21/2001
00TX-10351	ASOTIN COUNTY PUD NO 1	10/1/2001	8/28/2001
05TX-12101	AVISTA CORPORATION	1/1/2006	1/16/2006
96MS-95364	BENTON RURAL ELECTRIC ASSOCIATION	9/30/1996	7/2/1997
01TX-10352	BIG BEND ELECTRIC COOPERATIVE INC	10/1/2001	9/27/2001
02TX-11030	BPA POWER SERVICES	5/1/2002	5/8/2002
02TX-10925	BPA POWER SERVICES	8/1/2005	7/7/2005
01TX-10648	CANBY UTILITY BOARD	10/1/2001	9/20/2001
02TX-10870	CENTRAL LINCOLN PUD	3/1/2002	2/25/2002
00TX-10316	CENTRAL MONTANA ELECTRIC POWER COOP INC	6/21/2000	5/2/2000
98TX-10178	CENTRALIA CITY LIGHT	10/31/1998	10/26/1998
01TX-10654	CITY OF ALBION	10/1/2001	9/7/2001
01TX-10524	CITY OF ASHLAND	10/1/2001	7/24/2001
01TX-10530	CITY OF BANDON	10/1/2001	7/18/2001
00TX-10357	CITY OF BLAINE	9/30/2001	4/9/2001
01TX-10411	CITY OF BONNERS FERRY	10/1/2001	6/20/2001
10TX-14682	CITY OF BURLEY	2/22/2010	2/22/2010
01TX-10435	CITY OF CASCADE LOCKS	10/1/2001	9/12/2001
01TX-10721	CITY OF CHENEY	10/1/2001	9/25/2001
01TX-10544	CITY OF CHEWELAH	10/1/2001	7/24/2001
10TX-14683	CITY OF DECLO	3/8/2010	3/8/2010
01TX-10425	CITY OF DRAIN	10/1/2001	5/14/2001
96MS-96082	CITY OF ELLENSBURG	9/30/1996	4/22/1997
00TX-10297	CITY OF FOREST GROVE	9/30/2001	5/15/2001
10TX-14686	CITY OF HEYBURN	2/25/2010	2/25/2010
10TX-14692	CITY OF IDAHO FALLS DBA IDAHO FALLS POWER	3/1/2010	3/1/2010
01TX-10742	CITY OF MCCLEARY	10/1/2001	10/10/2001
01TX-10452	CITY OF MILTON	10/1/2001	6/5/2001
00TX-10332	CITY OF MILTON-FREEWATER	10/1/2001	9/24/2001
10TX-14687	CITY OF MINIDOKA	3/15/2010	3/15/2010
01TX-10428	CITY OF MONMOUTH	10/1/2001	5/2/2001
01TX-10545	CITY OF PLUMMER	10/1/2001	8/20/2001
06TX-12443	CITY OF PORT ANGELES, LIGHT DEPARTMENT	10/1/2006	9/27/2006
01TX-10644	CITY OF RICHLAND	10/1/2001	10/3/2001
10TX-14689	CITY OF RUPERT	2/22/2010	2/22/2010
10TX-14726	CITY OF SODA SPRINGS	3/5/2010	3/5/2010
00TX-10365	CITY OF SUMAS	9/30/2001	3/15/2001
00TX-10320	CITY OF TROY POWER & LIGHT	9/30/2001	4/14/2000
10TX-15038	CITY OF TROY POWER & LIGHT	7/27/2010	7/27/2010
06TX-12416	CITY OF WEISER	1/1/2007	9/8/2006

List of BPA's NITS, GF, and PTP Agreements as of August 15, 2011

ACTIVE BPA TRANSMISSION SERVICE AGREEMENTS AS OF AUGUST 15, 2011			
01TX-10410	CLALLAM COUNTY PUD NO 1	10/1/2001	7/17/2001
01TX-10381	CLARK PUBLIC UTILITIES	10/1/2001	9/14/2001
96MS-96040	CLEARWATER POWER CO	11/30/1997	3/2/1998
00TX-10370	COLUMBIA BASIN ELECTRIC COOP	10/1/2001	9/20/2001
00TX-10338	COLUMBIA POWER COOP ASSOCIATION	10/1/2001	8/13/2001
01TX-10463	COLUMBIA RIVER PUD	10/1/2001	9/26/2001
00TX-10331	COLUMBIA RURAL ELECTRIC ASSOCIATION INC	10/1/2001	9/25/2001
01TX-10483	CONSOLIDATED IRRIGATION DISTRICT NO 19	10/1/2001	9/12/2001
01TX-10546	COULEE DAM, TOWN OF	10/1/2001	10/2/2001
01TX-10691	COWLITZ COUNTY PUD NO 1	10/1/2001	9/27/2001
10TX-14684	EAST END MUTUAL ELECTRIC COMPANY LTD	2/23/2010	2/23/2010
01TX-10420	ELMHURST MUTUAL POWER & LIGHT COMPANY	10/1/2001	6/28/2001
01TX-10695	EMERALD PUD	10/1/2001	9/17/2001
01TX-10380	ENERGY NORTHWEST	10/1/2001	9/21/2001
02TX-10793	EUGENE WATER & ELECTRIC BOARD	12/1/2001	11/21/2001
10TX-14761	FARMERS ELECTRIC COMPANY LTD	3/17/2010	3/17/2010
01TX-10448	FERRY COUNTY PUD NO 1	10/1/2001	5/11/2001
00TX-10350	FLATHEAD ELECTRIC COOP INC	10/1/2001	3/15/2001
96MS-96063	GLACIER ELECTRIC COOPERATIVE INC	9/30/1996	4/30/1997
01TX-10680	GRANT COUNTY PUD NO. 2	10/1/2001	9/17/2001
00TX-10333	HARNEY ELECTRIC COOPERATIVE INC	9/30/2001	4/9/2001
01TX-10521	HERMISTON ENERGY SERVICES	10/1/2001	9/19/2001
01TX-10364	HOOD RIVER ELECTRIC COOPERATIVE	10/1/2001	10/1/2001
10TX-14672	IDAHO COUNTY LIGHT & POWER COOP ASSOCIATION INC	3/22/2010	3/22/2010
01TX-10450	INLAND POWER & LIGHT COMPANY	10/1/2001	9/17/2001
01TX-10451	KITTITAS COUNTY PUD NO 1	10/1/2001	4/18/2001
96MS-95360	KOOTENAI ELECTRIC COOPERATIVE INC	9/30/1996	5/22/1997
01TX-10419	LAKEVIEW LIGHT & POWER	3/7/2001	3/7/2001
01TX-10415	LEWIS COUNTY PUD NO 1	10/1/2001	5/17/2001
96MS-96062	LINCOLN ELECTRIC COOPERATIVE INC	9/30/1996	3/24/1997
10TX-15110	LOST RIVER ELECTRIC COOPERATIVE INC	10/25/2010	10/25/2010
07TX-12496	LOWER VALLEY ENERGY INC	1/1/2007	12/26/2006
01TX-10427	MASON COUNTY PUD NO 1	10/1/2001	6/20/2001
01TX-10421	MASON COUNTY PUD NO 3	10/1/2001	6/15/2001
02TX-10856	MCMINNVILLE WATER AND LIGHT	2/1/2002	1/29/2002
00TX-10308	MIDSTATE ELECTRIC COOPERATIVE INC	9/30/2001	8/28/2000
96MS-96065	MISSION VALLEY POWER	9/30/1996	4/18/1996
96MS-96064	MISSOULA ELECTRIC COOPERATIVE INC	9/30/1996	3/24/1997
01TX-10449	MODERN ELECTRIC WATER CO	10/1/2001	5/15/2001
01TX-10487	NESPELEM VALLEY ELECTRIC COOPERATIVE INC	10/1/2001	6/14/2001
01TX-10409	NORTHERN WASCO COUNTY PUD	10/1/2001	5/23/2001
96MS-96068	OHOP MUTUAL LIGHT CO	9/30/1996	4/23/1997
98TX-10128	ORCAS POWER & LIGHT COOPERATIVE	6/30/1999	5/27/1999

List of BPA's NITS, GF, and PTP Agreements as of August 15, 2011

ACTIVE BPA TRANSMISSION SERVICE AGREEMENTS AS OF AUGUST 15, 2011			
00TX-10295	OREGON TRAIL ELECTRIC CONSUMERS COOP INC	4/30/2001	1/26/2001
01TX-10422	PACIFIC COUNTY PUD NO. 2	10/1/2001	6/8/2001
96MS-96041	PACIFIC NORTHWEST GENERATING COOP	9/30/1996	5/30/1997
00TX-10327	PACIFICORP	10/1/1999	11/30/2000
09TX-14534	PACIFICORP	11/1/2009	10/28/2009
96MS-96074	PARKLAND LIGHT & WATER COMPANY	9/30/1996	4/28/1997
01TX-10390	PENINSULA LIGHT COMPANY	10/1/2001	5/7/2001
01TX-10460	PORT OF SEATTLE (SEA-TAC)	7/1/2001	6/25/2001
01TX-10605	PORT TOWNSEND PAPER CORPORATION	10/1/2001	8/15/2001
00TX-10294	RAVALLI COUNTY ELECTRIC COOPERATIVE INC	9/30/2001	4/10/2000
10TX-14688	RIVERSIDE ELECTRIC COMPANY LTD	2/24/2010	2/24/2010
00TX-10309	SALEM ELECTRIC	9/30/2001	5/23/2000
10TX-15111	SALMON RIVER ELECTRIC COOPERATIVE INC	10/21/2010	10/21/2010
01TX-10470	SKAMANIA COUNTY PUD NO 1	10/1/2001	7/11/2001
10TX-14690	SOUTH SIDE ELECTRIC INC	3/15/2010	3/15/2010
04TX-11639	SOUTHERN MONTANA ELECTRIC G&T COOPERATIVE, INC.	6/1/2004	5/11/2004
01TX-10697	SPRINGFIELD UTILITY BOARD	10/1/2001	9/13/2001
01TX-10457	SURPRISE VALLEY ELECTRIFICATION CORP	10/1/2001	7/13/2001
01TX-10591	TANNER ELECTRIC COOPERATIVE	10/1/2001	9/18/2001
01TX-10682	TILLAMOOK PUD	10/1/2001	9/18/2001
01TX-10604	TOWN OF EATONVILLE	10/1/2001	8/14/2001
01TX-10391	TOWN OF STEILACOOM	10/1/2001	4/26/2001
01TX-10606	UMPQUA INDIAN UTILITY COOPERATIVE	10/1/2001	8/14/2001
10TX-14691	UNITED ELECTRIC COOP INC	2/22/2010	2/22/2010
01TX-10543	US AIR FORCE - FAIRCHILD AFB	10/1/2001	7/26/2001
01TX-10430	US BUREAU OF INDIAN AFFAIRS - WAPATO	10/1/2001	10/1/2001
01TX-10353	US DEPT OF ENERGY - RICHLAND	10/1/2001	9/14/2001
00TX-10366	US DEPT OF NAVY - BANGOR	10/1/2000	11/13/2000
01TX-10538	US DOE NATIONAL ENERGY TECHNOLOGY LABORATORY (NETL)	10/1/2001	7/17/2001
10TX-14751	USBR - MID-PACIFIC REGION	4/22/2010	4/22/2010
01TX-10433	VERA WATER AND POWER	9/30/2001	4/11/2001
96MS-96046	VIGILANTE ELECTRIC COOP INC	9/30/1996	3/28/1997
01TX-10471	WAHKIAKUM COUNTY PUD NO 1	10/1/2001	6/6/2001
01TX-10440	WASCO ELECTRIC COOP INC	10/1/2001	8/14/2001
01TX-10423	WELLS RURAL ELECTRIC COMPANY	9/30/2001	4/20/2001
98TX-10173	WHATCOM COUNTY PUD NO 1	11/30/1998	11/30/1998
05TX-12068	YAKAMA POWER	2/1/2006	2/23/2006

List of BPA's NITS, GF, and PTP Agreements as of August 15, 2011

ACTIVE BPA TRANSMISSION SERVICE AGREEMENTS AS OF AUGUST 15, 2011			
POINT-TO-POINT TRANSMISSION SERVICE AGREEMENT (PTP)			
Contract Number	Customer	Effective	Execution
10TX-14892	ADAGE LLC	6/23/2010	6/23/2010
01TX-10630	ALCOA INC	10/1/2000	9/9/2001
07TX-12459	ALCOA POWER MARKETING LLC	11/1/2006	10/26/2006
08TX-13479	ALTERNITY WIND POWER LLC	5/7/2008	5/7/2008
06TX-12243	AMERICAN ELECTRIC POWER SERVICE CORPORATION	3/1/2006	3/1/2006
07TX-12526	ARLINGTON WIND POWER PROJECT LLC	1/1/2007	1/8/2007
96MS-96008	AVISTA CORPORATION	10/1/1996	10/1/1996
97TX-50002	AVISTA ENERGY INC	7/31/1997	7/25/1997
07TX-12631	BARCLAYS BANK PLC	10/11/2007	10/11/2007
97TX-10041	BENTON COUNTY PUD NO 1	5/31/1997	7/14/1997
10TX-14832	BLUESTAR ENERGY SERVICES INC	5/27/2010	5/27/2010
04TX-11671	BP ENERGY COMPANY	2/28/2004	3/4/2004
01TX-10688	BP WEST COAST PRODUCTS, LLC	1/26/2005	1/26/2005
08TX-13135	BP WIND ENERGY NORTH AMERICA INC	5/5/2008	5/5/2008
02TX-11144	BPA POWER SERVICES	6/1/2002	8/16/2002
96MS-95363	BPA POWER SERVICES	9/30/1996	3/25/1997
07TX-12615	CAITHNESS SHEPHERDS FLAT LLC	10/22/2007	10/22/2007
01TX-10734	CARGILL POWER MARKETS, LLC	9/30/2001	9/17/2001
08TX-13707	CEP FUNDING LLC	10/21/2008	10/21/2008
01TX-10714	CHELAN COUNTY PUD NO 1	10/1/2001	9/11/2001
10TX-14835	CITY OF BURBANK	5/26/2010	5/26/2010
06TX-12367	CITY OF REDDING	8/1/2006	8/3/2006
02TX-11177	CLARK PUBLIC UTILITIES	8/1/2002	8/13/2002
01TX-10649	CLATSKANIE PUD	10/1/2001	9/20/2001
09TX-14053	CLIPPER WINDPOWER DEVELOPMENT COMPANY, INC.	5/22/2009	5/22/2009
02TX-10942	COLUMBIA ENERGY PARTNERS LLC	9/1/2005	8/31/2005
01TX-10685	COLUMBIA FALLS ALUMINUM COMPANY	10/1/2001	9/27/2001
01TX-10459	CONOCOPHILLIPS CO	4/24/2001	4/24/2001
02TX-11265	CONSTELLATION ENERGY COMMODITIES GROUP INC	10/1/2002	10/1/2002
08TX-12971	COWLITZ COUNTY PUD NO 1	11/14/2007	11/14/2007
02TX-10967	CP ENERGY MARKETING (US) INC	5/16/2002	5/16/2002
09TX-14100	DB ENERGY TRADING LLC	6/18/2009	6/18/2009
09TX-14135	DIVERSIFIED ENERGY TRANSMISSION LLC	6/1/2009	6/1/2009
09TX-13902	EDF TRADING NORTH AMERICA LLC	1/14/2009	1/14/2009
07TX-12793	EMERALD PUD	9/11/2007	9/11/2007
09TX-13833	ENDURE ENERGY LLC	12/22/2008	12/22/2008
09TX-13949	ENERFIN ENERGY COMPANY INC		4/29/2009
08TX-13169	ENXCO DEVELOPMENT CORPORATION	3/25/2008	3/25/2008
02TX-10791	EUGENE WATER & ELECTRIC BOARD	11/1/2006	11/21/2001
09TX-14147	EURUS COMBINE HILLS II, LLC	6/22/2009	6/22/2009
06TX-12381	EURUS ENERGY AMERICA	4/9/2008	4/9/2008

List of BPA's NITS, GF, and PTP Agreements as of August 15, 2011

ACTIVE BPA TRANSMISSION SERVICE AGREEMENTS AS OF AUGUST 15, 2011			
	CORPORATION		
02TX-11145	EVERGREEN ALUMINUM, LLC	7/1/2002	6/26/2002
07TX-12488	FINLEY BIOENERGY LLC	9/1/2007	2/6/2007
06TX-12259	FLATHEAD ELECTRIC COOP INC	2/1/2006	3/6/2006
97TX-10043	FRANKLIN COUNTY PUD NO 1	5/31/1997	7/14/1997
10TX-14737	GAELECTRIC LLC	3/10/2010	3/10/2010
02TX-11262	GOLDEN NORTHWEST ALUMINUM INC	10/1/2002	9/26/2002
01TX-10679	GRANT COUNTY PUD NO. 2	10/1/2001	9/17/2001
96MS-96083	GRAYS HARBOR COUNTY PUD NO 1	4/30/1997	6/24/1997
10TX-14919	GREENWING ENERGY AMERICA CORPORATION	6/28/2010	6/28/2010
98TX-10154	HERMISTON POWER LLC	5/10/1999	5/10/1999
01TX-10718	HINSON POWER CO INC	2/1/2002	2/19/2002
07TX-12892	HORIZON WIND ENERGY LLC	10/4/2007	10/4/2007
00TX-10367	IBERDROLA RENEWABLES INC	9/30/2001	11/1/2000
99TX-10204	IBERDROLA RENEWABLES INC	7/1/2001	1/19/1999
01TX-10576	IDAHO POWER COMPANY	10/1/2001	9/14/2001
96MS-96108	IDAHO POWER COMPANY	9/30/1996	6/25/1997
08TX-13762	INVENERGY ENERGY MANAGEMENT LLC	10/2/2008	10/2/2008
06TX-12448	J P MORGAN VENTURES ENERGY CORPORATION	11/1/2006	10/5/2006
02TX-11231	J. ARON & COMPANY	9/1/2002	9/18/2002
06TX-12142	K3 WIND LLC	10/1/2007	4/4/2006
03TX-11509	KAISER ALUMINUM FABRICATED PRODUCTS LLC	10/1/2003	10/15/2003
97TX-10038	KLICKITAT COUNTY PUD NO 1	9/30/1997	3/12/1998
06TX-12244	L&M ANGUS RANCH	3/1/2006	2/17/2006
10TX-14701	LEWIS COUNTY PUD NO 1	4/5/2010	4/5/2010
02TX-10944	LOS ANGELES DEPARTMENT OF WATER & POWER	10/4/2002	12/19/2002
09TX-14148	LOTUS GROUP USA INC	6/15/2009	6/15/2009
08TX-13671	LOWER VALLEY ENERGY INC	11/17/2008	11/17/2008
09TX-13834	MACQUARIE ENERGY LLC	12/22/2008	12/22/2008
10TX-14918	MARIAH WIND LLC	6/28/2010	6/28/2010
01TX-10733	MCMINNVILLE WATER AND LIGHT	10/1/2001	9/26/2001
05TX-11864	MERRILL LYNCH COMMODITIES, INC	11/1/2004	11/2/2004
05TX-11927	MIDDLE FORK IRRIGATION DIST	1/1/2006	3/18/2005
01TX-10472	MIRANT ENERGY TRADING, LLC	5/8/2001	5/24/2001
97TX-10031	MORGAN-STANLEY CAPITAL GROUP, INC	3/31/1997	3/21/1997
08TX-13620	NATURENER USA LLC	7/1/2008	7/1/2008
10TX-15143	NOBLE AMERICAS ENERGY SOLUTIONS LLC	10/25/2010	10/25/2010
09TX-14164	NORTHERN WASCO COUNTY PUD	6/24/2009	6/24/2009
07TX-12569	NORTHPOINT ENERGY SOLUTIONS	5/23/2007	5/23/2007
08TX-13053	NORTHWEST GEOTHERMAL CO OPERATED BY DAVENPORT POWER, LLC	2/19/2008	2/19/2008

List of BPA's NITS, GF, and PTP Agreements as of August 15, 2011

ACTIVE BPA TRANSMISSION SERVICE AGREEMENTS AS OF AUGUST 15, 2011			
10TX-14568	NORTHWEST WIND PARTNERS LLC	11/3/2009	11/3/2009
09TX-13823	NORTHWESTERN CORPORATION D/B/A/ NORTHWESTERN ENERGY	12/30/2008	12/30/2008
02TX-11115	NORTHWESTERN ENERGY, LLC	7/1/2002	6/3/2002
01TX-10686	OKANOGAN COUNTY PUD NO 1	10/1/2001	9/25/2001
06TX-12141	OREGON TRAIL WIND FARM LLC	10/1/2007	4/5/2006
07TX-12614	OREGON WIND LLC	6/11/2008	6/11/2008
03TX-11466	PACIFIC GAS & ELECTRIC COMPANY	9/1/2003	9/29/2003
01TX-10424	PACIFIC NORTHWEST GENERATING COOP	1/31/2001	1/31/2001
04TX-11722	PACIFICORP	8/1/2004	7/28/2004
08TX-13657	PATU WIND FARM LLC	7/18/2008	7/18/2008
02TX-10875	PEND OREILLE COUNTY PUD NO 1	1/1/2002	12/31/2001
98TX-10174	PORTLAND GENERAL ELECTRIC COMPANY	10/22/1998	10/22/1998
96MS-96095	PORTLAND GENERAL ELECTRIC COMPANY	9/30/1996	4/1/1997
09TX-14507	PORTLAND GENERAL ELECTRIC COMPANY	12/8/2009	12/8/2009
96MS-96084	POWEREX CORP	1/31/1999	1/28/1999
99TX-10251	POWEREX CORP	6/12/1999	5/31/1999
05TX-11918	PP&L MONTANA LLC	1/1/2005	2/22/2005
08TX-13030	PPL ENERGYPLUS, LLC	1/4/2008	1/4/2008
08TX-13066	PS POWER GENERATION	2/14/2008	2/14/2008
05TX-11952	PUBLIC SERVICE COMPANY OF COLORADO	5/15/2005	4/18/2005
06TX-12195	PUGET SOUND ENERGY INC	1/1/2006	12/27/2005
03TX-11539	PUGET SOUND ENERGY INC	4/1/2004	4/1/2004
01TX-10748	PUGET SOUND ENERGY INC	10/1/2001	9/26/2001
07TX-12449	RAFT RIVER ENERGY I, LLC	6/1/2007	10/25/2006
10TX-14623	RAINBOW ENERGY MARKETING CORPORATION	12/9/2009	12/9/2009
08TX-13480	RES AMERICAS INC	5/12/2008	5/12/2008
02TX-11128	SACRAMENTO MUNICIPAL UTILITY DISTRICT	8/15/2002	8/15/2002
01TX-10456	SAN DIEGO GAS & ELECTRIC	4/20/2001	4/19/2001
96MS-96018	SEATTLE CITY LIGHT	7/31/2000	7/26/2000
07TX-12705	SEMPRA ENERGY TRADING	6/27/2007	6/27/2007
00TX-10286	SHELL ENERGY NORTH AMERICA (US) LP	1/1/2000	2/9/2000
04TX-11833	SHERMAN COUNTY	10/1/2007	4/27/2006
01TX-10461	SIERRA PACIFIC POWER CO	1/1/2002	6/1/2001
99TX-10228	SNOHOMISH COUNTY PUD NO 1	3/31/1999	4/1/1999
96MS-96092	SNOHOMISH COUNTY PUD NO 1	9/30/1996	6/25/1997
10TX-14641	SOUTHERN CALIFORNIA EDISON COMPANY	1/4/2010	1/4/2010
01TX-10706	SPRINGFIELD UTILITY BOARD	10/1/2001	9/13/2001
10TX-14833	SWAGGART ENERGY TRANSMISSION LLC	5/25/2010	5/25/2010

List of BPA's NITS, GF, and PTP Agreements as of August 15, 2011

ACTIVE BPA TRANSMISSION SERVICE AGREEMENTS AS OF AUGUST 15, 2011			
98TX-10103	TACOMA POWER	2/1/1998	1/29/1998
10TX-14548	TECK METALS LTD	12/22/2009	12/22/2009
10TX-15177	TGP DEVELOPMENT COMPANY LLC	10/12/2010	10/12/2010
05TX-11957	THE ENERGY AUTHORITY	10/1/2006	9/26/2006
10TX-14883	TIMINE DEVELOPMENT CORPORATION	6/14/2010	6/14/2010
98TX-10172	TRANSALTA ENERGY MARKETING (US) INC	8/5/1998	8/26/1998
10TX-14843	TRANSCANADA ENERGY SALES LTD	8/3/2010	8/3/2010
00TX-10344	TURLOCK IRRIGATION DISTRICT	7/20/2000	7/20/2000
02TX-10965	UBS AG, LONDON BRANCH	3/18/2002	3/14/2002
05TX-11399	US GEOTHERMAL	6/1/2006	6/24/2005
04TX-11655	WAPA - ROCKY MOUNTAIN DIVISION	3/1/2004	2/13/2004
10TX-14732	WASATCH WIND INTERMOUNTAIN LLC	3/10/2010	3/10/2010
09TX-13934	WEST BUTTE WIND POWER LLC	3/2/2009	3/2/2009
08TX-13142	WESTERN RENEWABLE POWER LLC	3/27/2008	3/27/2008
08TX-13610	WHEAT FIELD WIND POWER PROJECT LLC	6/9/2008	6/9/2008
08TX-12968	WIND POWER ASSOCIATES	11/2/2007	11/2/2007
07TX-12456	WINDY POINT PARTNERS LLC	1/1/2007	12/15/2006

List of BPA's NITS, GF, and PTP Agreements as of August 15, 2011

ACTIVE BPA TRANSMISSION GRANDFATHERED (GF) SERVICE AGREEMENTS AS OF AUGUST 15, 2011

Contract Number	Customer	Contract Description	Effective	Execution
3RD AC CAPACITY OWNERSHIP (3DAC)				
DE-MS79-94BP94521	PUGET SOUND ENERGY INC	PNW AC INTERTIE CAPACITY OWNERSHIP	9/26/1994	10/11/1994
DE-MS79-94BP94522	SEATTLE CITY LIGHT	PNW AC INTERTIE CAPACITY OWNERSHIP	9/27/1994	9/27/1994
DE-MS79-94BP94523	POWER RESOURCES COOPERATIVE	PNW AC INTERTIE CAPACITY OWNERSHIP	9/27/1994	9/27/1994
DE-MS79-94BP94524	TACOMA POWER	PNW AC INTERTIE CAPACITY OWNERSHIP	9/27/1994	9/27/1994
DE-MS79-94BP94525	SNOHOMISH COUNTY PUD NO 1	PNW AC INTERTIE CAPACITY OWNERSHIP	9/27/1994	9/27/1994
DE-MS79-95BP94628	PACIFICORP	PNW AC INTERTIE CAPACITY OWNERSHIP	1/1/1995	1/1/1995
CAPACITY SALE STATEMENT OF PRINCIPLES (CAPSOP)				
07TX-12669	FRANKLIN COUNTY PUD NO 1	CAPACITY SALE - SOP	5/15/2007	5/15/2007
DE-MS79-88BP92497	PACIFICORP	SP FIRM CAPACITY SALE (RESTATED)	8/31/1991	9/27/1994
FORMULA POWER TRANSMISSION (FPT)				
DE-MS79-85BP92186	AVISTA CORPORATION	SETTLEMENT EXCHANGE	9/17/1985	9/17/1985
DE-MS79-79BP90013	OKANOGAN COUNTY PUD NO 1	TRANSMISSION - WELLS PROJECT (FPT)	8/31/1978	5/29/1979
DE-MS79-94BP94280	PACIFICORP	DC INTERTIE & NETWORK TRANSMISSION (FPT)	6/1/1994	6/1/1994
DE-MS79-94BP94316	PACIFICORP	TRANSMISSION - HERMISTON GENERATION PROJECT (FPT)	10/3/1994	10/3/1994
14-03-14612	PACIFICORP	TRANSMISSION - EXCESS CAPACITY - ASTORIA/TILLAMOOK SEGREGATED SYSTEMS (FPT)	10/31/1959	1/20/1960
DE-MS79-94BP94333	PACIFICORP	FPT - MIDPOINT - MERIDIAN LINE	6/1/1994	6/1/1994
DE-MS79-86BP92260	PORTLAND GENERAL ELECTRIC COMPANY	TRANSMISSION (FPT) - BOARDMAN UNIT 1	12/31/1985	12/30/1985
DE-MS79-95BP94151	POWER RESOURCES COOPERATIVE	TRANSMISSION (FPT,UFT)	12/31/1994	12/29/1994
DE-MS79-85BP92185	PUGET SOUND ENERGY INC	SETTLEMENT AGREEMENT	9/17/1985	9/17/1985

List of BPA's NITS, GF, and PTP Agreements as of August 15, 2011

INTERCONNECTION & EXCHANGE (I&EXCH)				
95MS-94600	SIERRA PACIFIC POWER COMPANY AND PACIFICORP	ALTURAS INTERTIE PROJECT INTERCONNECTION/O&M	2/23/1996	2/15/1996
INTEGRATION OF RESOURCES (IR)				
DE-MS79-95BP94769	ACPC INC	GENERAL TRANSMISSION (IR)	4/19/1995	4/19/1995
DE-MS79-95BP94764	ALCOA INC	GENERAL TRANSMISSION (IR)	4/12/1995	4/18/1995
DE-MS79-95BP94763	COLUMBIA FALLS ALUMINUM COMPANY	GENERAL TRANSMISSION (UFT) (IR)	4/18/1995	4/18/1995
DE-MS79-95BP94768	EVERGREEN ALUMINUM LLC	GENERAL TRANSMISSION (IR)	5/3/1995	5/3/1995
DE-MS79-95BP94762	GOLDENDALE ALUMINUM CORPORATION	INTEGRATION OF RESOURCES (IR)	5/4/1995	5/4/1995
DE-MS79-95BP94765	KAISER ALUMINUM FABRICATED PRODUCTS LLC	GENERAL TRANSMISSION (UFT) (IR)	5/5/1995	5/5/1995
14-03-001-13574	CHELAN COUNTY PUD NO 1 PUGET SOUND ENERGY INC	INTEGRATION OF RESOURCES (IR)	12/23/1957	12/23/1957
DE-MS79-88BP92461	AVISTA CORPORATION CITY OF SPOKANE PUGET SOUND ENERGY	TRANSMISSION (IR) - SPOKANE WASTE DISPOSAL FACILITY	7/28/1988	7/28/1988
DE-MS79-90BP92781	NORTHERN WASCO COUNTY PUD PUGET SOUND ENERGY	TRANSMISSION (IR)	2/20/1990	2/20/1990
DE-MS79-95BP94766	NORTHWEST ALUMINUM CO	GENERAL TRANSMISSION (IR)	4/10/1995	4/10/1995
DE-MS79-95BP94775	PORT TOWNSEND PAPER CORPORATION	GENERAL TRANSMISSION	5/16/1995	5/16/1995
DE-MS79-94BP93947	PUGET SOUND ENERGY INC	GENERAL TRANSMISSION (IR)	12/1/1994	12/1/1994
14-03-45241	PUGET SOUND ENERGY INC	EXCHANGE AGREEMENT	1/31/1966	1/24/1966
DE-MS79-95BP94767	REYNOLDS METALS COMPANY	GENERAL TRANSMISSION (IR)	5/3/1995	5/3/1995
INTERTIE (ITIE)				
DE-MS79-94BP94285	PACIFICORP	AC INTERTIE TRANSMISSION	6/1/1994	6/1/1994
DE-MS79-94BP94332	PACIFICORP	AMENDED AND RESTATED AC INTERTIE AGREEMENT FILED W/FERC 3/22/06	3/16/1993	3/20/2006
DE-MS79-87BP92340	PORTLAND GENERAL ELECTRIC COMPANY	INTERTIE	7/29/1988	7/29/1988

DE-MS79-91BP93094	IDAHO POWER COMPANY	INTERTIE TRANSMISSION	7/25/1991	7/25/1991
DE-MS79-94BP94613	PORTLAND GENERAL ELECTRIC COMPANY	MOU - NW AC INTERTIE CAPACITY OWNERSHIP	9/15/1994	9/15/1994
DE-MS79-92BP93964	PUGET SOUND ENERGY INC	TRANSMISSION - MOU WESTSIDE NORTHERN INTERTIE & AREA	1/31/1992	1/31/1992
DE-MS79-95BP93081	PUGET SOUND ENERGY INC	WESTSIDE NORTHERN INTERTIE & AREA TRANSMISSION	10/3/1995	10/3/1995
MEMORANDUM OF AGREEMENT NON-NETWORK RESOURCES (MOA)				
02TX-10949	US ARMY COE - PORTLAND DISTRICT	MOA EQUIPMENT INVENTORY	3/29/2004	3/29/2004
02TX-11175	BPA POWER SERVICES	TRANSFER SERVICE SCHEDULING	9/1/2002	8/21/2002
SALES/EXCHANGE STATEMENT OF PRINCIPLES (SESOP)				
DE-MS79-94BP93958	CITY OF RIVERSIDE	DIVERSITY EXCHANGE	8/12/1994	7/5/1994
95MS-94811	MULTI	EXCHANGE/INTERIM - AZUSA, BANNING & COLTON	10/31/1995	11/27/1995
DE-MS79-88BP92527	PUGET SOUND ENERGY INC	PBL SALE & EXCHANGE AGREEMENT	10/31/1988	11/23/1988
DE-MS79-87BP92412	CITY OF GLENDALE	SP FIRM CAPACITY EXCHANGE	1/31/1988	1/28/1988
DE-MS79-94BP93658	CITY OF PASADENA, PASADENA WATER & POWER	SP FIRM CAPACITY EXCHANGE - PASADENA	5/1/1995	6/29/1994
DE-MS79-87BP92413	CITY OF PASADENA, PASADENA WATER & POWER	SP FIRM ENERGY EXCHANGE	7/31/1988	1/28/1988
DE-MS79-87BP92411	CITY OF BURBANK	SP FIRM ENERGY EXCHANGE	1/31/1988	1/28/1988
DE-MS79-90BP92858	RIVERSIDE ELECTRIC COMPANY LTD	SP FIRM PEAKING CAPACITY EXCHANGE	6/15/1990	6/15/1990
STATEMENT OF PRINCIPLES (SOP)				
96MS-96060	BPA POWER SERVICES	MEMORANDUM OF AGREEMENT (STATEMENT OF PRINCIPLES) - TBL/PBL	9/30/1996	11/10/1999
TRANSFER (XFR)				
DE-MS79-93BP92638	OKANOGAN COUNTY PUD NO 1	(GTA) TRANSFER	6/29/1990	8/8/1995
DE-MS79-89BP92384	PORTLAND GENERAL ELECTRIC COMPANY	GENERAL TRANSFER AGREEMENT (GTA)	12/31/1989	12/11/1989
DE-MS79-88BP92458	PACIFICORP	GENERAL TRANSFER AGREEMENT (GTA)	2/1/1988	2/1/1988

DE-MS79-82BP90049	PACIFICORP	GENERAL TRANSFER AGREEMENT (GTA)	5/4/1982	5/4/1982
DE-MS79-88BP92436	SIERRA PACIFIC POWER CO	GENERAL TRANSFER AGREEMENT (GTA)	2/25/1988	2/25/1988
DE-MS79-88BP92287	PACIFICORP	GENERAL TRANSFER AGREEMENT (GTA) (UFT)	1/26/1988	4/12/1988
14-03-58624	MULTI	GENERAL TRANSFER: GTA	5/18/1967	5/18/1967
DE-MS79-80BP90066	DOUGLAS COUNTY PUD NO 1	GENERAL TRANSFER: GTA (USBR) (NOTE: COMPLETE EXH G REVISIONS IN TBL CCIS)	2/27/1981	2/27/1981
14-03-69166	MULTI	MIDWAY ASHE LINE	2/18/1977	2/18/1977
14-03-69167	CLARK PUBLIC UTILITIES	TRANSFER - FELIDA TAP	9/2/1976	7/8/1977
14-03-49101	PUGET SOUND ENERGY INC	TRANSFER (SKY MEADOWS/TEANAWAY MW SERVICE)	3/5/1974	3/5/1974
DE-MS79-89BP92807	TACOMA POWER	TRANSFER - PARKLAND/ELMHURST	9/15/1989	9/14/1989
14-03-86602	COLOCKUM TRANSMISSION COMPANY	TRANSFER - ROCKY REACH-VALHALLA-ALCOA	3/7/1969	3/7/1969
14-03-75365	PUGET SOUND ENERGY INC	TRANSFER - SEDRO WOOLEY TAP/CHIEF JOE-SNOHOMISH 2 LINE	12/16/1967	10/14/1968
14-03-75628	PUGET SOUND ENERGY INC	TRANSFER - SULTON OR MONROE TO MAPLE VALLEY	10/14/1968	10/14/1968
14-03-75037	EUGENE WATER & ELECTRIC BOARD	TRANSFER AGREEMENT	1/23/1968	1/23/1968
DE-MS79-79BP90000	SIERRA PACIFIC POWER CO	TRANSFER AGREEMENT	7/12/1979	7/12/1979
14-03-37017	PORTLAND GENERAL ELECTRIC COMPANY	TRANSFER AGREEMENT	9/13/1973	9/13/1973
14-03-68435	PUGET SOUND ENERGY INC	TRANSFER AGREEMENT	7/31/1967	7/26/1967
14-03-79117	BENTON COUNTY PUD NO 1	TRANSFER AGREEMENT	2/1/1977	4/28/1977
EW-78-Y-83-0036	NORTHERN WASCO COUNTY PUD	TRANSFER AGREEMENT	6/30/1976	3/15/1978
DE-MS79-90BP93116	MULTI	TRANSMISSION - IDAHO-NORTHWEST TRANSFER CAPABILITY	10/1/1990	9/27/1990
14-03-47930	WASCO ELECTRIC COOPERATIVE INC	TRANSMISSION SERVICE AT KLONDIKE	11/19/1964	7/19/1965
TREATY				
99EO-40003	BRITICH COLUMBIA HYDRO & POWER AUTHORITY	COLUMBIA RIVER TREATY	4/1/1998	9/15/2024
OTHER				
DE-MW79-81BP90210	NORTHWESTERN ENERGY	TRANSMISSION (UFT) - COLSTRIP PROJECT	4/17/1981	10/1/2027

DE-MW79-81BP90210	PORTLAND GENERAL ELECTRIC	TRANSMISSION (UFT) - COLSTRIP PROJECT	4/17/1981	10/1/2027
DE-MW79-81BP90210	PACIFICORP	TRANSMISSION (UFT) - COLSTRIP PROJECT	4/17/1981	10/1/2027
DE-MW79-81BP90210	AVISTA CORPORATION	TRANSMISSION (UFT) - COLSTRIP PROJECT	4/17/1981	10/1/2027
DE-MW79-81BP90210	PUGET SOUND ENERGY	TRANSMISSION (UFT) - COLSTRIP PROJECT	4/17/1981	10/1/2027

Appendix E

Dispatchers Standing Order 319

Montana-Pacific Northwest Remedial Action Scheme

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