1997 PACIFIC NORTHWEST COORDINATION AGREEMENT

Agreement

for

Coordination of Operations

among

Power Systems of the Pacific Northwest

June 18, 1997

Conformed Copy

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1997 Pacific Northwest Coordination Agreement

This 1997 Pacific Northwest Coordination Agreement ("Agreement"), executed as of June 18, 1997, is by and among THE UNITED STATES OF AMERICA ("United States"), acting by and through THE BONNEVILLE POWER ADMINISTRATOR OF THE DEPARTMENT OF ENERGY ("Administrator"), THE DIVISION ENGINEER, NORTHWESTERN DIVISION, CORPS OF ENGINEERS, DEPARTMENT OF THE ARMY ("Division Engineer"), and THE REGIONAL DIRECTOR, BUREAU OF RECLAMATION, PACIFIC NORTHWEST REGION, DEPARTMENT OF THE INTERIOR ("Regional Director"); THE UNITED STATES ENTITY designated pursuant to Article XIV of the "Treaty between Canada and the United States of America Relating to the Cooperative Development of the Water Resources of the Columbia River Basin"; THE CITY OF EUGENE, OREGON, a municipal corporation of the State of Oregon; THE CITY OF SEATTLE, WASHINGTON, a municipal corporation of the State of Washington; THE CITY OF TACOMA, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT NO. 2 OF GRANT COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT NO. 1 OF PEND OREILLE COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT NO. 1 OF DOUGLAS COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT NO. 1 OF COWLITZ COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUGET SOUND ENERGY, INC., a corporation; PORTLAND GENERAL ELECTRIC COMPANY, a corporation; PACIFICORP, a corporation; THE WASHINGTON WATER POWER COMPANY, a corporation; THE MONTANA POWER COMPANY, a corporation; and COLOCKUM TRANSMISSION COMPANY, INC., a corporation.

WITNESSETH:

WHEREAS, the Parties operate major hydroelectric generating plants or electric systems which serve the Pacific Northwest area; and

WHEREAS, the Parties have achieved substantial economies and additional firm power resources for the Pacific Northwest in the past by voluntarily coordinating the planning and operation of their facilities through the Northwest Power Pool and by entering into various contracts and arrangements, including the 1964 Pacific Northwest Coordination Agreement and amendments thereto; and

WHEREAS, coordination for the production of power must take into consideration non-power uses for water resources and must be achieved as a part of the comprehensive development and management of water resources for maximum sustained benefit for the public good; and

WHEREAS, the United States and Canada have entered into the "Treaty between Canada and the United States of America Relating to the Cooperative Development of the Water Resources of the Columbia River Basin" ("Treaty"), which Treaty contemplates coordination among the producers of power in the Pacific Northwest and the Canadian facilities subject to the Treaty; and

WHEREAS, the Administrator and the Division Engineer have been designated the United States Entity pursuant to Executive Order No. 11177 and Article XIV of the Treaty; and

WHEREAS, Canada is entitled under the Treaty to certain power benefits ("Canadian Entitlement") from the United States; and

WHEREAS, the United States and Public Utility District No. 1 of Chelan County, Washington, Public Utility District No. 1 of Douglas County, Washington, and Public Utility District No. 2 of Grant County, Washington (collectively "Mid-Columbia PUDs") first entered into the Canadian Entitlement Allocation Agreements in 1964, which agreements specified the portion of the Canadian Entitlement that the Mid-Columbia PUDs agreed to deliver to the Administrator during the duration of such agreements based upon the existence of coordination among the producers of power in the Pacific Northwest and the Canadian facilities subject to the Treaty; and

WHEREAS, the United States and the Mid-Columbia PUDs have entered into a subsequent set of Canadian Entitlement Allocation Extension Agreements dated April 30, 1997, which agreements specify the portion of the Canadian Entitlement that the Mid-Columbia PUDs agree to deliver to the Administrator pursuant to the terms of such agreements based upon the existence of coordination among the producers of power in the Pacific Northwest and the Canadian facilities subject to the Treaty; and

WHEREAS, the Administrator is authorized to transmit and dispose of electric power energy generated at various Federal hydroelectric projects in the Pacific Northwest in accordance with the Bonneville Project Act, approved August 20, 1937, as amended, the Reclamation Project Act of August 4, 1939, the Flood Control Act of December 22, 1944, the Preference Act of August 31, 1964, as amended, the Transmission System Act of October 18, 1974, as amended, the Northwest Power Act of December 5, 1980, as amended, and pursuant to the following orders of the Secretary of the Interior: No. 2563 dated May 2, 1950, and No. 2860 dated January 19, 1962, as amended; and

WHEREAS, the Administrator is authorized by Order No. 2860, as amended, to enter into such contracts, agreements, and arrangements, upon such terms and conditions and in such manner as the Administrator may deem necessary, as provided in the Bonneville Project Act, as amended; and

WHEREAS, the Secretary of the Army is authorized by various public laws related to the development of the Columbia River Basin to construct, operate, and maintain dam and reservoir projects for multiple purposes, one purpose being the generation of power; and

WHEREAS, the Secretary of the Army is to deliver electric power and energy which, in the Secretary's opinion, is not required in the operation of hydroelectric projects to the Secretary of Energy for transmission and disposal in accordance with Section 5 of the 1944 Flood Control Act; and

WHEREAS, the Secretary of the Army and the Chief of Engineers have delegated necessary and appropriate authority to the Division Engineer; and

WHEREAS, the Commissioner of Reclamation has delegated necessary and appropriate authority to the Regional Director; and

WHEREAS, the three Federal agencies, acting through the Administrator, the Division Engineer, and the Regional Director, in order to execute this 1997 PNCA on behalf of the United States, have entered into an agreement of even date herewith entitled "Memorandum of Agreement Between the Federal Parties to the 1997 PNCA";

NOW, THEREFORE, in consideration of the premises and of the mutual benefits from covenants hereinafter set forth, the Parties do hereby agree as follows.

Part I. Introductory Provisions

Section 1. Term and Termination

(a) Effective Date

Except as provided in parts III, *Operations*, and IV, *Rates and Charges*, and section 16, *Regulatory and Judicial Authorities*, this Agreement shall become effective the February 1 following execution by all of the Parties listed in the first paragraph of this Agreement and shall terminate on September 15, 2024.

(b) Suspension of Comprehensive Agreement

On the Effective Date, the Comprehensive Agreement shall remain in effect, but performance thereof by the Parties to this Agreement shall be suspended and all outstanding obligations of such Parties shall be subject to, and shall continue in force pursuant to, the terms of this Agreement; *provided* should any Party be prevented by operation of law from performing this Agreement, then that Party shall, while so prevented, and to the extent not prohibited by applicable law or regulation, perform pursuant to the Comprehensive Agreement and shall have all of the rights and shall be bound to perform all of the obligations of such Party consistent with all of the terms of the Comprehensive Agreement.

Section 2. Definitions

The following capitalized terms shall have the following meanings when used in this Agreement.

Actual Adjusted Energy Load and ***Actual Adjusted Peak Load*** of a Party means its actual energy load and actual peak load, respectively, adjusted by including the amount of the Party's firm commitments to deliver energy or capacity from its Firm Resources to other Parties and non-Parties and by excluding the amount of such Party's firm rights to receive energy or capacity from other Parties' Firm Resources. The Actual Adjusted Energy Load and the Actual Adjusted Peak Load of the Coordinated System means the sums of the Actual Adjusted Energy Loads and Actual Adjusted Peak Loads, respectively, of all of the individual Parties.

Actual Adjusted Load means the aggregate of the Actual Adjusted Energy Load and Actual Adjusted Peak Load of a Party or of the Coordinated System, as the case may be.

Actual Energy Capability ("AEC") means for any Period the amount of energy received and energy generated by a Party during such Period, as determined pursuant to subsection 9(b), *Actual Energy Capability*. The Actual Energy Capability of the Coordinated System means the sum of the Actual Energy Capabilities of the individual Parties.

Actual Firm Energy Load means for either a Party or the Coordinated System its Estimated Firm Energy Load updated to reflect actual conditions.

Actual Peaking Capability ("APC") means for any Party the Peaking Capability of all of such Party's Firm Resources, except those scheduled for Maintenance Outage, after, consistent with this Agreement, deduction of Forced Outage Reserves and adjustments for delivery or receipt of Interchange Capacity. The Actual Peaking Capability of the Coordinated System means the sum of the Actual Peaking Capabilities of all of the individual Parties.

Annual Reservoir means a reservoir that is able to refill in the current Operating Year from empty at the end of the Critical Period associated with the Firm Load Carrying Capability established for the current Operating Year to the maximum allowable elevation by the immediately following July 31 using the Refill Volume.

Assigned Water means for a reservoir the water equivalent of In Lieu Energy that the Reservoir Party controlling such reservoir has delivered to a downstream Party.

Assured Refill Curve ("ARC") means a reservoir operating guideline based on the Refill Volume used to refill a reservoir and to determine its Base Energy Content Curve.

Base Energy Content Curve ("Base ECC") means a reservoir operating guideline determined under section 7, *Determination of Base and Variable Energy Content Curves*, whose effect is to limit the Coordinated System's production of secondary energy, such curve to be used as a starting point for developing Proportional Draft Points.

Canadian Storage means the reservoir storage in Canada existing on the Effective Date that affects Columbia River flows.

Comprehensive Agreement means the *Agreement for Coordination of Operations among Power Systems of the Pacific Northwest* executed as of September 15, 1964, as subsequently amended by the parties thereto.

Conservative Streamflow Estimate means with respect to any Project for the current and next Period the most probable forecast of Unregulated Streamflows by the Reservoir Party for such Project and, for any remaining Periods of the Operating Year, the forecast of Unregulated Streamflows based on the latest Volume Forecast for such Periods. If such forecasts are not available, the Unregulated Streamflows in the Load Determination Re-regulation shall be used under this Agreement in lieu of such forecasts.

Coordinated System means the aggregated Systems of each of the Parties, including generating plants, reservoirs, transmission systems, and associated facilities owned or controlled by such Party and coordinated by such Party under this Agreement. The Coordinated System shall include Treaty Storage to the extent such inclusion is not inconsistent with the Treaty.

Coordinating Group means the group established pursuant to subsection 5(a), *Coordinating Group*.

Critical Peaking Period means the Period(s) (not necessarily consecutive) during an Operating Year when the relationship of the Coordinated System's computed Peaking Capability to its Estimated Adjusted Peak Load indicates the highest probability of load loss for such Period(s) pursuant to the methodology in Exhibit F, *Reserves*.

Critical Period means the consecutive Periods during which, based on the streamflows of the Historical Period of Record adjusted for changes in consumptive uses, the Firm Resources of the Parties serve the least total amount of the Coordinated System's Estimated Firm Energy Load.

Critical Period Energy Capability means for a Party or the Coordinated System the average energy that can be produced from its Firm Resources (excluding energy reserves pursuant to subsection 8(c), *Energy Reserve*, and Firm Resources scheduled for Maintenance Outage) under coordinated operations during the Critical Period based on full use of available stored water that can be shaped to the Coordinated System's Estimated Adjusted Energy Load during the Critical Period.

Critical Rule Curve ("CRC") means a guide for the storage and release of storage water from each reservoir to be used under this Agreement to develop the Coordinated System's Firm Energy Load Carrying Capability when the Coordinated System is in Proportional Draft. The Critical Rule Curve(s) for each reservoir is determined pursuant to subsection 6(l), *Determination of Critical Rule Curves*, and shall consist of one or more end-of-Period reservoir elevations needed to supply the Coordinated System's Firm Energy Load Carrying Capability when the Coordinated System is in Proportional Draft.

Cyclic Reservoir means a reservoir that is not an Annual Reservoir.

Deficit Party means a Party that has an Estimated Adjusted Energy Load that is less than the sum of its (i) Estimated Firm Energy Load and (ii) commitments under this Agreement to deliver firm energy to other Parties from its Firm Resources, minus its firm rights under this Agreement to receive energy from other Parties' Firm Resources.

Delivering Party means a Party that delivers or returns energy pursuant to this Agreement.

Drawdown Period means the consecutive Period(s) during which Coordinated System reservoirs are being drafted to meet load. The Drawdown Period for each Operating Year begins on or after August 1 when there is a sustained decrease in the Coordinated System's Storage Energy resulting from either Coordinated System reservoir drafts or drafts that would have occurred if Coordinated System reservoirs adhered to the Energy Content Curves. The Drawdown Period ends after January 1 when the Coordinated System's storage indicates a sustained increase in Storage Energy or when a sustained decrease in thermal generation occurs to avoid an increase in such Storage Energy, whichever occurs first.

Effective Date means the date the Agreement becomes effective pursuant to the terms of this Agreement.

Energy Content Curve ("ECC") means a guide to reservoir operations determined pursuant to section 7, *Determination of Base and Variable Energy Content Curves*, that is used to determine certain operating rights and obligations under this Agreement.

Estimated Adjusted Energy Load ("EAEL") and Estimated Adjusted Peak Load ("EAPL") of a Party means the maximum energy load and the maximum Peak Load amounts that such Party reasonably expects could be served from its anticipated Firm Energy Load Carrying Capability and Firm Peak Load Carrying Capability, respectively. The Estimated Adjusted Energy Load and Estimated Adjusted Peak Load of the Coordinated System means the sums of the Estimated Adjusted Energy Loads and Estimated Adjusted Peak Loads, respectively, of all of the Parties. Each Party shall, for purposes of running the Preliminary Regulation pursuant to subsection 6(c), *Preliminary Regulation*, furnish to each other Party preliminary Estimated Adjusted Energy Loads that such Party reasonably expects could be served from its anticipated Firm Load Carrying Capability. Each Party shall modify its Estimated Adjusted Load pursuant to section 6, *Determination of Firm Load Carrying Capability*, such that its Estimated Adjusted Load equals its Firm Load Carrying Capability determined by use of the Final Regulation pursuant to subsection 6(m), *Establishment of Firm Load Carrying Capability*.

Estimated Adjusted Load means the aggregate of the Estimated Adjusted Energy Load and the Estimated Adjusted Peak Load of a Party or of the Coordinated System, as the case may be.

Estimated Firm Energy Load ("EFEL") and ***Estimated Firm Peak Load*** means a Party's best estimate of its firm energy load and firm Peak Load, excluding firm commitments to deliver energy or capacity to other Parties, which it expects to serve from its Firm Resources and from its firm rights under this Agreement to receive energy and capacity from other Parties' Firm Resources. Firm commitments to supply energy or capacity outside the geographical area specified in the definition of System shall be separately identified when submitted under subsection 6(a), *Load and Firm Resource Data*. The Estimated Firm Energy Load and the Estimated Firm Peak Load of the Coordinated System means the sums of the Estimated Firm Energy Loads and the Estimated Firm Peak Loads, respectively, of all of the Parties.

Estimated Firm Load means the aggregate of the Estimated Firm Energy Load and the Estimated Firm Peak Load of a Party or of the Coordinated System, as the case may be.

Final Regulation means the Coordinated System regulation run pursuant to subsection 6(j), *Final Regulation*, to be used under this Agreement to (i) provide information from which Critical Rule Curves are determined pursuant to subsection 6(l), *Determination of Critical Rule Curves*, (ii) determine the Coordinated System's final Critical Period Energy Capability, and (iii) after adjusting for final Restoration, determine each Party's Firm Load Carrying Capability pursuant to subsection 6(m), *Establishment of Firm Load Carrying Capability*; *provided* the Final Regulation shall be the Load Determination Re-regulation if Firm Energy Load Carrying Capabilities are established from the first year of the Critical Period.

Firm Energy Load Carrying Capability ("FELCC") and ***Firm Peak Load Carrying Capability ("FPLCC")*** means for the Coordinated System the firm energy load and Peak Load, respectively (as determined pursuant to this Agreement), that the Coordinated System is able to serve in any Period (inside or outside of the Critical Period) from the Firm Resources of the Coordinated System after deducting the required energy reserves and Forced Outage Reserve. For individual Parties Firm Energy Load Carrying Capability and Firm Peak Load Carrying Capability means the energy load and the Peak Load, respectively (as determined pursuant to this Agreement), that such Party is able to serve in any Period on a firm basis under this Agreement. Each Party's Firm Energy Load Carrying Capability and Firm Peak Load Carrying Capability shall be determined in accordance with paragraph 6(h)(6), *Determination of Firm Load Carrying Capability*, established in accordance with subsection 6(m), *Establishment of Firm Load Carrying Capability*, adjusted in accordance with subsection 6(o), *Adjustments to Established Firm Load Carrying Capabilities*, and further adjusted in accordance with subsection 9(k), *Adjustments in Firm Energy Load Carrying Capability During Operating Year*.

Firm Load Carrying Capability ("FLCC") means the aggregate of the Firm Energy Load Carrying Capability and the Firm Peak Load Carrying Capability of a Party or of the Coordinated System, as the case may be.

Firm Resources means the following facilities and firm arrangements for the acquisition of power generated from facilities that in each case are available to a Party to supply firm energy and firm capacity and that are submitted for coordination under this Agreement.

(i) *Projects Inside the Coordinated System*

Projects owned, leased, or otherwise controlled by a Party from time to time during the term of this Agreement, in each case located within the geographical area identified in the definition of System, except for resources committed to others under a type of agreement described in (ii) below of this definition; *provided* Projects above the tailrace of Bonneville Dam shall be Firm Resources coordinated under this Agreement and other hydroelectric resources may be Firm Resources coordinated under this Agreement at the option of such Party. Subject to section 24, *Re-negotiation*, and subsections 26(b), *Transfer of a Project to a Non-Party,* and 26(c), *Transfer of a Project to a Party*, once a resource in this category is submitted as a Firm Resource, it shall remain a Firm Resource for the duration of this Agreement.

(ii) Share of Projects Inside the Coordinated System

All resources under an agreement or agreements that provide that a Party's System obtains from time to time during the term of this Agreement all or a portion of all of the various and several energy benefits available from a particular Project or particular hydroelectric resource specified in such agreement, in each case located within the geographical area identified in the definition of System; *provided* resources from Projects above the tailrace of Bonneville Dam shall be Firm Resources coordinated under this Agreement and other hydroelectric resources may be Firm Resources coordinated under this Agreement at the option of such Party. Subject to section 24, *Re-negotiation*, and subsections 26(b), *Transfer of a Project to a Non-Party,* and 26(c), *Transfer of a Project to a Party*, once a resource from a Project in this category is submitted as a Firm Resource, it shall remain a Firm Resource during the term of this Agreement for as long as the submitting Party has control over such resource.

(iii) Thermal and Miscellaneous Resources

All or any part of dependable thermal and miscellaneous resources available to a Party that are dedicated to serve Northwest load and included in the Coordinated System at the option of such Party; *provided* the submitting Party's ratio of coordinated thermal Firm Resources to coordinated hydroelectric Firm Resources does not exceed seven to one; *provided further* that The Montana Power Company may continue to coordinate all of the thermal resources it submits to coordination the first year of this Agreement notwithstanding the above-referenced limitation. Thermal and miscellaneous Firm Resources may include, but shall not be limited to, contracts for the purchase of firm power or energy from resources not otherwise a part of the Coordinated System and arrangements by a Party for a supply of firm power or energy from its own resources not otherwise included in its System. A submitting Party retains the right in its sole discretion to remove a thermal and miscellaneous resource after its inclusion as a Firm Resource.

The Coordinated System's Firm Resource means the aggregate of the Firm Resources submitted by all of the Parties pursuant to subsection 6(a), *Load and Firm Resource Data*. Firm Resources submitted by any Party for coordination shall be listed on Exhibit D, *The Coordinated System's*

Firm Resources as of June 18, 1997, to this Agreement. Pursuant to paragraph 6(b)(1), *Adjusting Firm Resources*, Exhibit D, *Coordinated System's Firm Resources as of June 18, 1997,* shall be updated annually by the Coordinating Group to conform to information submitted by the Parties in their subsection 6(a), *Load and Firm Resource Data*, data submittal.

Flexibility Adjustment Account ("FAA") means the account for each Party maintained by the Coordinating Group that advances or delays Firm Energy Load Carrying Capability of such Party pursuant to subsection 9(k), *Adjustments in Firm Energy Load Carrying Capability During Operating Year*.

Forced Outage means an outage, full or partial, due to any failure of the turbine, generator, any auxiliary components, or pertinent structures, not including a System's main-grid transmission system facilities, that requires a generating unit to reduce production. To be considered forced an outage must satisfy one of the following conditions: (i) It is necessary immediately to take the generating unit or equipment out of service or reduce generation; or (ii) it is necessary to take the generating unit or equipment out of service or reduce generation before a normally-scheduled maintenance period or a low-load period of sufficient length to make the necessary repairs.

Forced Outage Rate means for a generating unit the probability of such unit being out of service in any Period as expressed by a ratio of the expected hours out of service divided by the total hours in such Period.

Forced Outage Reserve means generating capacity held in reserve as required by subsection 8(b), *Forced Outage Reserves*, to replace the generation lost because of a Forced Outage so as to avoid loss of load.

Heavy Load Hours ("HLH") means the hours from 0700 hours to 2200 hours, Monday through Saturday, excluding national holidays.

Historical Period of Record means the historical period beginning August 1928 (updated at a minimum every ten years) containing the record of streamflows used for planning under this Agreement.

Holding Energy ("HE") means energy transferred between Parties pursuant to subsection 9(c), *Delivery and Return of Holding Energy*, in order to delay the draft of a reservoir. The affected Parties shall prepare schedules of Holding Energy transfers pursuant to paragraph 6(i)(4), *Designation of Holding Energy*.

Hydroelectric Firm Energy Load Carrying Capability ("Hydroelectric FELCC") means the Coordinated System's total Firm Energy Load Carrying Capability less that portion of such Firm Energy Load Carrying Capability attributable to thermal and miscellaneous Firm Resources after adjusting those Firm Resources for the planned Maintenance submitted pursuant to paragraph 6(a)(4), *Maintenance,* and revised pursuant to paragraph 6(f)(3), *Revisions to Maintenance.*

In Lieu Energy means energy (i) delivered pursuant to subsection 9(j), *Release of Water From Storage and In Lieu Energy Deliveries*, by a Reservoir Party to the owner of a downstream Project in an amount equivalent to the amount of energy that could have been produced at such downstream Project if water above the Energy Content Curve had been released as requested by the owner of such downstream Project, or (ii) returned pursuant to subsection 9(j), *Release of*

Water From Storage and In Lieu Energy Deliveries, by the owner of a downstream Project to a Reservoir Party.

Indicated Export means for both planning and operational purposes the amount by which a Party's Firm Energy Load Carrying Capability in a Period is less than the latest estimate of the energy capability of its Firm Resources in such Period determined in accordance with this Agreement, as such estimate is adjusted for (i) estimates of Restoration, and (ii) energy reserves calculated pursuant to subsection 8(c), *Energy Reserve*.

Indicated Exporting Party means for planning purposes a Party whose Firm Energy Load Carrying Capability determined in the Modified Regulation is in any Period greater than the latest estimate of the energy capability of its Firm Resources for that Period, as such estimate is adjusted for (i) estimates of Restoration, and (ii) energy reserves calculated pursuant to subsection 8(c), *Energy Reserve.*

Indicated Import means for both planning and operational purposes the amount by which a Party's Firm Energy Load Carrying Capability in a Period is greater than the latest estimate of the energy capability of its Firm Resources in such Period determined in accordance with this Agreement, as such estimate is adjusted for (i) estimates of Restoration, and (ii) energy reserves calculated pursuant to subsection 8(c), *Energy Reserve*.

Indicated Importing Party means for planning purposes a Party whose Firm Energy Load Carrying Capability determined in the Modified Regulation is in any Period less than the latest estimate of the energy capability of its Firm Resources for that Period, as such estimate is adjusted for (i) estimates of Restoration, and (ii) energy reserves calculated pursuant to subsection 8(c), *Energy Reserve.*

Indicated Receiving Party means for operational purposes a Party that has a right to receive and may require the delivery of energy pursuant to this Agreement but that has not requested the delivery of all such energy.

Indicated Supplying Party means for operational purposes a Party that is required to deliver energy pursuant to this Agreement but that has not been requested to deliver all such energy.

Initial Shift Allocation Level means one of the following levels of Estimated Adjusted Energy Load elected pursuant to paragraph 6(a)(8), *Specification of Intention to Shift and Initial Shift Allocation Level,* by the Shifting Party to be used throughout the Critical Period for the purposes of allocating shift: (i) its average Critical Period hydroelectric capability plus its average non-hydroelectric Firm Resources' capability in the Shift Allocation Interval; or (ii) its average Firm Resources in the Shift Allocation Interval. Such Shifting Party's election shall remain fixed during the Critical Period.

Interchange Capacity means capacity transferred on request between Parties pursuant to subsection 9(e), *Interchange Capacity*, to supply any part of a Party's deficiency between its Actual Peaking Capability and Firm Peak Load Carrying Capability.

Interchange Energy means energy transferred on request between Parties pursuant to subsection 9(d), *Interchange Energy*, either to (i) supply any part of a Party's deficiency between its Actual Energy Capability and Firm Energy Load Carrying Capability, or (ii) return such energy to the Supplying Party. Interchange Energy includes both Regular Interchange Energy and Loaned Interchange Energy.

Light Load Hours ("LLH") means hours other than Heavy Load Hours.

Load Determination Re-regulation ("LDR") means the hydroelectric re-regulation to be used under this Agreement to conform the initial Critical Period planning regulation for the established Firm Energy Load Carrying Capability to the current Operating Year planning requirements pursuant to section 6(o), *Adjustments to Established Firm Load Carrying Capabilities*.

Loaned Interchange Energy means Interchange Energy that (i) is identified as loaned when requested pursuant to paragraph 9(d)(1), *Delivery of Interchange Energy*, and (ii) can be called back in accordance with clause 9(d)(3)(A)(ii), *Loaned Interchange Energy,* to the extent a Supplying Party's Actual Energy Capability, excluding the use of thermally-generated energy, is less than its Firm Energy Load Carrying Capability.

Maintenance Outage means for a Party any Firm Resource outage, other than a Forced Outage, that is for the purpose of routine or special maintenance without regard to whether such outage is scheduled or occurs before or after such Party's subsection 8(a), *Maintenance*, submittal.

Modified Regulation means the Coordinated System regulation run pursuant to subsection 6(h), *Modified Regulation*, to be used under this Agreement to (i) estimate the Coordinated System's modified-maximum Critical Period Energy Capability, (ii) after adjustment for estimated Restoration pursuant to subparagraph 6(h)(1)(E), *Adjust Firm Resources to Estimated Adjusted Energy Load*, provide a modified estimate of each Party's Critical Period Energy Capability, and (iii) provide an initial estimate of each Party's Firm Load Carrying Capability.

Non-shapeable Energy Capability means in any Period in which the Coordinated System's energy capability cannot match the Coordinated System's Estimated Adjusted Energy Load, measured in average megawatts, the difference between (i) the Coordinated System's energy capability and (ii) the Coordinated System's Estimated Adjusted Energy Load plus the Offset, if any, for that Period.

Offset means for planning purposes the adjustment(s), measured in average megawatts, to the Coordinated System's energy capability necessary to distribute surpluses or deficits uniformly between the Critical Period Energy Capability and the Coordinated System Estimated Adjusted Energy Loads. Offsets shall equal the difference between the Coordinated System's energy capability and the Coordinated System's Estimated Adjusted Energy Load; *provided* in Periods containing Non-shapeable Energy Capability Offsets shall equal zero.

Offset Interval means the sequential Periods where energy can be shaped between such Periods and energy surpluses or deficits can be uniformed.

Operating Year means August 1 through July 31.

Other-than-Treaty Storage means Canadian Storage and modifications thereto that are not Treaty Storage.

Party means any party to this Agreement; *provided* when action is to be taken under this Agreement by the United States it may be taken, as appropriate, by independent action of the Administrator, the Division Engineer, or the Regional Director, notwithstanding that the United States is the actual Party and is ultimately responsible under this Agreement.

Peak Load means the highest clock-hour-average load for a stated period.

Peak Load Hours ("PLH") means any six or fewer hours (irrespective of whether such hours are consecutive, Heavy Load Hours, or Light Load Hours) that a Party may declare daily as Peak Load Hours pursuant to this Agreement. Once made by a Party, a Peak-Load-Hours designation shall be applied consistently with respect to such Party under all pertinent sections of this Agreement.

Peaking Capability means for a Firm Resource the maximum Peak Load carrying ability of such Firm Resource or for a Party the sum of all Peak Load carrying abilities of all of such Party's Firm Resources. The Peaking Capability of the Coordinated System means the sum of the Peaking Capabilities of all of the Parties.

Period means a calendar month; *provided* when the Critical Period begins or ends within a calendar month Period means that portion of such calendar month that is part of the Critical Period and that portion of such calendar month that is not part of the Critical Period.

Potential Spill Period means the period commencing upon a Reservoir Party's notification to all other Parties that a potential spill condition exists and continuing until the Reservoir Party notifies the Parties that the potential spill condition has ended.

Preliminary Regulation means the Coordinated System regulation run pursuant to subsection 6(c), *Preliminary Regulation*, to be used under this Agreement to (i) determine a preliminary maximum Critical Period Energy Capability for the Coordinated System, and (ii) after adjustment for estimated Restoration, estimate each Party's preliminary Critical Period Energy Capability.

Project means any hydroelectric generating facility or reservoir that is a Firm Resource and is used for power purposes in a Party's System.

Proportional Draft means the release of water to Proportional Draft Points pursuant to paragraph 9(g)(3), *Proportional Draft*.

Proportional Draft Points ("PDP") means target reservoir elevations established by the Coordinating Group when draft below the Energy Content Curves is necessary to develop the Coordinated System's Firm Energy Load Carrying Capability.

Provisional Draft means the release of water as permitted in subsection 9(l), *Provisional Energy*, that a Reservoir Party anticipates will cause its reservoir(s) to be below its end-of-Period Energy Content Curve(s) at the end of the current Period.

Provisional Energy means the energy generated from Provisional Draft.

Receiving Party means a Party that receives or requests receipt of an initial delivery of energy pursuant to subsection 9(c), *Delivery and Return of Holding Energy*, 9(d), *Interchange Energy*, 9(e), *Interchange Capacity*, 9(j), *Release of Water From Storage and In Lieu Energy Deliveries*, or 9(n), *Transfers Due To Forced Outage.* For the purposes of subsection 9(i), *Storage of Energy in Reservoirs*, the Receiving Party means a Reservoir Party that has accepted energy for storage in its System.

Refill-hold Period means the time interval between successive Drawdown Periods.

Refill Criterion means 98 percent of the Coordinated System's maximum storage capability measured in Storage Energy at the end of the Refill-hold Period.

Refill Regulation means a multi-year simulation of the operation of Projects over the Historical Period of Record used under this Agreement to determine Variable Energy Content Curves for the Coordinated System reservoirs pursuant to subparagraph 7(d)(4)(B), *Refill Regulation*.

Refill Volume means for each reservoir the volume equivalent of the streamflows corresponding to the third lowest volume Unregulated Streamflow at site in the Historical Period of Record during those Periods for which the Energy Content Curves indicate that such reservoir would be filling after such streamflow has been reduced by (i) minimum discharge requirements, (ii) non-power requirements for water at site and upstream, and (iii) water required for refill at upstream reservoirs. All Projects above the tailrace of Bonneville Dam shall use the same year (third lowest volume unregulated inflow) in determining the Refill Volume.

Regular Interchange Energy means all Interchange Energy that is not Loaned Interchange Energy.

Requesting Party means a Party that has an outstanding request for a delivery of energy from the System of a Party invoking a deferral pursuant to subsection 9(h), *Priorities on Use of Facilities for Power*.

Reservoir Party means a Party who owns reservoir storage or has a right to determine the operation of reservoir storage under an agreement described in (ii) of the definition of Firm Resource. The United States shall be a Reservoir Party with respect to Treaty Storage.

Restoration means transfers of Firm Energy Load Carrying Capability among the Parties pursuant to subsection 6(k), *Determination of Restoration*, so that all Parties can carry at least as much firm energy load from their Restoration Project(s) as they could have carried before development of Treaty Storage. The sum of all Restoration over the Coordinated System equals zero.

Restoration Project means for each submitting Party a Project listed on Exhibit E, *Limits of Rights to Restoration*, that qualifies such Party for Restoration under subsection 6(k), *Determination of Restoration*.

Settlement Criterion means 98 percent of the Storage Energy achieved in the Final Regulation at the start of the Critical Period.

Shifting Allocation Interval means for each Offset Interval the Period or group of sequential Periods commencing at the beginning of the Critical Period and ending in the last Period of that Offset Interval.

Shifting Party means a Party that shifts Firm Energy Load Carrying Capability from one year of the Critical Period to another year in the Critical Period by algebraically exceeding its Critical Period average surplus or deficit by at least two average megawatts in any interval within the Critical Period; *provided* that if shift occurs as a result of a change in participation in a joint-participation Project (Estimated Adjusted Energy Loads minus Estimated Firm Energy Loads are non-uniform), the difference corresponding to the change in participation shall not be considered in determining whether a Party is a Shifting Party. For purposes of this definition, an interval can be either an Operating Year for determining desired hydroelectric generation pursuant to submethods 6(b)-1.A., *Calculation of Desired Hydroelectric Generation*, and 6(g)-1.A., *Calculation of Desired Hydroelectric Generation*, or a Shifting Allocation Interval for allocating reductions in shift.

Spinning Reserve means the unloaded generating capacity of a Party's Firm Resources that is ready at all times to take load upon demand, together with any firm arrangements with another generation supplier for obtaining such capacity, and less any such firm arrangements for the supply of such capacity to another entity. Only that portion of such capacity or firm arrangements which is capable of serving load on a sustained basis within five minutes of the time of demand may be considered to be Spinning Reserve. A Party may consider as Spinning Reserve under this Agreement capacity being used to supply loads to which service can be interrupted upon five minutes' notice.

Spinning Reserve Requirement means the minimum Spinning Reserve which a Party is required to maintain pursuant to subsection 8(d), *Spinning Reserve*.

Storage Energy means for a Project the energy equivalent of the water stored above normal bottom elevation in such Project calculated using the Critical Period average water-to-energy conversion factors of all Projects at site and downstream. Storage Energy for a Party means the aggregate of the Storage Energy in all of such Party's reservoir Project(s). Storage Energy for the Coordinated System means the aggregate of the Storage Energy in all of the reservoir Projects of the Coordinated System.

Supplying Party means a Party that makes an initial delivery of energy pursuant to subsection 9(c), *Delivery and Return of Holding Energy*, 9(d), *Interchange Energy*, 9(e), *Interchange Capacity*, 9(j), *Release of Water From Storage and In Lieu Energy Deliveries*, 9(i), *Storage of Energy in Reservoirs*, or 9(n), *Transfers Due to Forced Outage.*

Surplus Party means a Party that has an Estimated Adjusted Energy Load in excess of the sum of its Estimated Firm Energy Load plus its commitments to deliver firm energy to other Parties from its Firm Resources and minus its firm rights to receive energy from other Parties' Firm Resources.

System means for any Party such Party's Firm Resources and transmission facilities that are adequately interconnected and that are interconnected with the Systems of other Parties to accomplish the objectives of this Agreement and that are located within the following geographical area: the states of Washington, Oregon, Idaho, Montana, and Wyoming; *provided* PacifiCorp's System shall also include its Firm Resources and transmission facilities that are located in California within the Klamath River Basin and are interconnected and coordinated with its other resources and facilities independently of this Agreement; *provided further* The City of Seattle's System shall also include its arrangement for power from the High Ross Treaty. The System of the United States shall include Treaty Storage to the extent such inclusion is not inconsistent with the Treaty.

Treaty means the "Treaty between the United States of America and Canada Relating to the Cooperative Development of the Water Resources of the Columbia River Basin," as supplemented from time to time by the exchange of notes between the governments of the United States and Canada.

Treaty Storage means the reservoir storage provided by Canada under Article II of the Treaty.

Trial Refill Regulation means the multi-year simulation of the operations of Projects run pursuant to subparagraph 7(d)(4)(A), *Trial Refill Regulation Based on Minimum Flow Variable Energy Content Curves*, using preliminary Variable Energy Content Curves for purposes of comparison with the Refill Regulation pursuant to subparagraph 7(d)(4)(B), *Refill Regulation*, in order to establish the final-planned Variable Energy Content Curves.

Unregulated Streamflow means the rate of flow at a given point due to natural-lake storage and river-channel restrictions adjusted to eliminate the effects of reservoir regulation.

Variable Energy Content Curve ("Variable ECC") means operating guidelines for Cyclic Reservoirs similar in purpose to the Base Energy Content Curve but based on the Volume Forecast. The Variable Energy Content Curve is determined by using a 95 percent probability that actual unregulated flows will equal or exceed forecasted unregulated flows pursuant to subsection 7(d), *Variable Energy Content Curves*.

Volume Forecast means for each reservoir in the Coordinated System the 50 percent confidence forecast and subsequent updates of the January through July volume runoff for such reservoir, as provided by the responsible reservoir systems; *provided* for reservoirs operated by the United States, the United States shall use the National Weather Service's (or its successor's) volume forecast for The Dalles, Oregon.

Section 3. Exhibits

Exhibits A through J, attached hereto and as subsequently updated by the Parties as provided in this Agreement, are incorporated into this Agreement.

Section 4. Coordination/Priorities

(a) Agreement to Coordinate

Subject to the terms and conditions of this Agreement, each of the Parties shall coordinate with all of the other Parties the planning and operation of its System.

(b) Priorities

The Parties shall coordinate their Systems to make available to each Party its optimum Firm Load Carrying Capability ("FLCC"), to provide optimum FLCC for the Coordinated System, and, consistent with these objectives, to produce the optimum amount of useable secondary energy for each Party.

Section 5. Implementation of Agreement

(a) Coordinating Group

(1) Structure and Duties

Each non-Federal Party and the Division Engineer, the Administrator, and the Regional Director shall appoint a representative and an alternate representative to represent such Party or entity as a member of the Coordinating Group to act for it in matters pertaining to this Agreement. Each Party shall notify all of the other Parties in writing of the name of any representative and alternate representative appointed pursuant to this paragraph 5(a)(1), and of any replacement therefor. At the request of any such representative, the Coordinating Group shall meet to perform one or more of the following actions.

(A) Implementation

Plan, operate, and resolve issues related to coordination of Firm Resources under this Agreement.

(B) Studies and Plans

Conduct studies and make plans relating to coordinated planning and operations pursuant to this Agreement for the information of the Parties. The studies and plans shall include those specifically required by this Agreement (for example, the Preliminary Regulation, the Modified Regulation, and the Final Regulation) and any other studies, plans, or determinations decided by the Coordinating Group to be necessary for purposes of this Agreement. The Coordinating Group may revise study and plan results and revise or waive deadlines related thereto.

(C) Organizational Rules

Adopt, modify, or supplement rules required for the proper functioning of the Coordinating Group. The rules governing the functioning of the Coordinating Group shall be as set out in Exhibit A, *Organizational Rules*.

(D) Costs

Approve the reasonable costs of the Coordinating Group and its staff, which may include reasonable costs for: engineering, secretarial, and clerical services; space; furniture and equipment rentals; utility services; supplies and miscellaneous office services. Each month the chairman of the Coordinating Group shall submit to each of the Parties an itemized statement showing all costs incurred by the Coordinating Group during the preceding month and the allocation of such costs among the Parties pursuant to this Agreement.

(E) Annual Methods and Procedures

Adopt, modify, or supplement annual methods and procedures. Annual methods and procedures may be used to implement or revise sections 6, *Determination of Firm Load Carrying Capability*, 7, *Determination of Base and Variable Energy Content Curves*, 8, *Maintenance and Reserves*, and 9, *Operating Procedures, Obligations, and Rights*, and to implement any of the other sections of this Agreement. The Coordinating Group's waiver of any provision in this Agreement through its adoption, modification, or supplementation of an annual method or procedure pursuant to this subparagraph 5(a)(1)(E) shall not be construed as a waiver of any other provision of this Agreement or as a waiver of the same or any similar provision in any other instance.

All decisions of the Coordinating Group shall be by unanimous consent; *provided* that an abstention or a failure to object shall be considered consent.

(2) Responsibility for Costs

Each Party shall pay all of the costs and expenses of its own Coordinating Group representative. Twenty-five percent of the Coordinating Group's general overhead and staff costs that have been consented to by the Coordinating Group (the "Lesser Cost") shall be shared pro rata among all of the Parties, other than the United States Entity, with each such Party's pro rata share being equal to the Lesser Costs multiplied by a fraction, the numerator of which is equal to the number of such Party's representatives to the Coordinating Group and the denominator of which is equal to the number of Parties plus one. The Administrator shall pay all of the Lesser Costs payable by the United States pursuant to this paragraph 5(a)(2). Seventy-five percent of the Coordinating Group's general overhead and staff costs that have been consented to by the Coordinating Group (the "Greater Costs") shall be shared pro rata among all of the Parties whose share of the Coordinated System's Firm Energy Load Carrying Capability ("FELCC") for the Operating Year is greater than one percent, with each such Party's pro rata share being equal to the Greater Costs multiplied by a fraction, the numerator of which is one and the denominator of which is equal to the number of Parties whose share of the Coordinated System's FELCC for such Operating Year is greater than one percent. The Administrator shall pay all of the Greater Costs payable by the United States pursuant to this paragraph 5(a)(2).

(b) Methods and Procedures

The Parties may adopt long-term methods and procedures and the Coordinating Group may adopt annual methods and procedures as provided in subparagraph 5(a)(1)(E), *Annual Methods and Procedures,* to implement or revise this Agreement. The long-term methods and procedures shall be as set out in Exhibit B, *Long-Term Methods and Procedures*, and the annual methods and procedures shall be as set out in Exhibit C, *Annual Methods and Procedures*. Methods and procedures pertaining to coordinated planning pursuant to this Agreement shall be hereafter referred to in this Agreement as "methods," and methods and procedures pertaining to coordinated operations pursuant to this Agreement shall be hereafter referred to in this Agreement as "procedures."

(1) Long-Term Methods and Procedures

(A) Term

Long-term methods and procedures shall, subject to subparagraph 5(b)(1)(B), *Adoption*, be effective, as specified therein, during the remaining term of this Agreement or for a period of ten Operating Years or five Operating Years.

(B) Adoption

The Parties may consider new long-term methods and procedures each Operating Year. Long-term methods and procedures agreed to and signed by all of the Parties by May 1 of any Operating Year shall become effective at the later of (i) the beginning of the following Operating Year, and (ii) the time of any required regulatory and other approval or permission required to be effective.

(C) Reopening

Any Party may reopen negotiation of any long-term method or procedure once every five years after such method or procedure becomes effective and the Parties shall consider any modification proposed by such Party. Any modification to a long-term method or procedure shall be only by unanimous vote of all of the Parties. Any such modification made by May 1 of any Operating Year shall become effective at the later of (i) the beginning of the following Operating Year, and (ii) the time of any required regulatory and other approval or permission required to be effective.

(D) Extension of Long-Term Method or Procedure at Expiration

Immediately prior to the expiration of any long-term method or procedure, the Coordinating Group shall determine whether any of the Parties object to extending such long-term method or procedure. Extension of any long-term method or procedure shall be by unanimous consent of all of the Parties; *provided* any long-term method or procedure not objected to by any of the Parties shall automatically be extended for a term equivalent to its initial term not to exceed the term of this Agreement.

(2) Annual Methods and Procedures

(A) Term

Annual methods and procedures subject to subparagraph 5(b)(2)(b), *Adoption*, shall be effective for a period of one Operating Year.

(B) Adoption

The Coordinating Group may consider annual methods and procedures each Operating Year. If any annual methods or procedures are presented to the Coordinating Group for approval, each member of the Coordinating Group shall either approve or disapprove the proposed methods or procedures in their entirety. Any annual method or procedure approved by all of the members of the Coordinating Group by May 1 of any Operating Year shall become effective at the later of (i) the beginning of the following Operating Year, and (ii) the time of any required regulatory and other approval or permission required to be effective.

If no Coordinating Group member objects by March 1 of any Operating Year to the extension of the current annual methods or procedures, such annual methods or procedures shall be automatically extended for the next Operating Year. The Coordinating Group member that objects shall specify the basis for its objection. If an objection is received, each member of the Coordinating Group shall negotiate in good faith with the objective of accommodating such objection by modification of such annual method or procedure.

(C) Transition of Annual Method or Procedure to Long-Term Method or Procedure

If an annual method or procedure has been in effect for five consecutive Operating Years, the Parties shall consider whether to adopt such annual method or procedure on a long-term basis.

Part II. Planning

Section 6. Determination of Firm Load Carrying Capability

Each year the Coordinating Group shall determine the Firm Load Carrying Capability ("FLCC") of the Coordinated System and of each individual Party in accordance with the following provisions. In connection with such determination, the Parties shall exchange all relevant data.

(a) Load and Firm Resource Data

Not later than February 1 of each Operating Year, each of the Parties shall provide to each of the other Parties the following data applicable to the Periods commencing on the following August 1.

(1) Load Data

Load data including (i) Estimated Firm Load, (ii) estimated secondary energy load, and (iii) Estimated Adjusted Load that such Party reasonably expects could be supplied from its anticipated FLCC including estimated Restoration. Estimated Firm Load is a basic requirement for planning. Each Party shall make these estimates to the best of its ability.

(2) Plant Data

To the extent not provided with respect to a previous Operating Year, all hydroelectric and thermal plant data regarding the Firm Resources of such Party including Project Unregulated Streamflows for the Historical Period of Record, reservoir capacity, conversion factors and peaking capacities throughout the operating range, operating restrictions, minimum flow limitations, limitations required for non-power uses, fuel conversion rates, and any other data reasonably anticipated by such Party to be necessary for the determination of FLCC.

(3) Data Regarding Power Transfers with Others Outside the Coordinated System

Data relating to amounts of energy and capacity that a Party expects to receive from or deliver outside the Coordinated System.

(4) Maintenance

Schedule of Maintenance Outages in accordance with subsection 8(a), *Maintenance*.

(5) New Firm Resources

To the extent not previously provided pursuant to this Agreement, service schedule for new or additional Firm Resources.

(6) Firm Resource Retirements

Firm Resources affecting generating capability listed in Exhibit D, *Coordinated System's Firm Resources as of June 18, 1997,* that are scheduled to be permanently taken out of service, terminated, retired, or abandoned; *provided* any retirement by any Party of a Project with seasonal storage shall have been preceded by a minimum of four years' notice to all other Parties, unless such retirement resulted from, was due to, or was caused by one or more uncontrollable forces as defined in section 21, *Uncontrollable Forces*.

(7) Removal of Firm Resources

Thermal or miscellaneous Firm Resources listed in Exhibit D, *Coordinated System's Firm Resources as of June 18, 1997,* or coordinated under this Agreement during the previous Operating Year that are being removed from coordination under this Agreement.

(8) Specification of Intention to Shift and Initial Shift Allocation Level

Specification of Operating Year(s) in which such Party anticipates being a Shifting Party as reflected in its submitted Estimated Adjusted Energy Loads ("EAEL"), together with its Initial Shift Allocation Level. If a Shifting Party fails to declare an Initial Shift Allocation Level, its EAEL shall be set to its average Firm Resources in the Initial Shift Allocation Interval.

While Surplus and Deficit Parties may reallocate their EAELs between Periods in the Critical Period pursuant to paragraph 6(a)(1), *Load Data*, a Surplus Party may not submit EAELs that would show a deficit in any Period in the Critical Period and a Deficit Party cannot submit EAELs that would show a surplus in any Period in the Critical Period.

(b) Necessary Actions Prior to Running the Preliminary Regulation

The Coordinating Group shall take the following actions prior to running the Preliminary Regulation.

(1) Adjusting Firm Resources

Adjust the Firm Resources and reflect the changes to the Firm Resources in Exhibit D, *Coordinated Firm Resources as of June 18, 1997,* as follows.

(A) Addition or Removal of Firm Resources

Add to each Party's Firm Resources the new or additional Firm Resources scheduled for service, as specified by such Party pursuant to paragraph 6(a)(5), *New Firm Resources*, and remove from each Party's Firm Resources the Firm Resources scheduled (i) to be taken out of service, terminated, retired, or abandoned, as specified by such Party pursuant to paragraph 6(a)(6), *Firm Resource Retirements***,** or (ii) to be removed from coordination, as specified by such Party pursuant to paragraph 6(a)(7), *Removal of Firm Resources*.

(B) Delay in Availability

Adjust the Firm Resources of each Party to reflect any delays or advances in the availability of such Firm Resources as reflected in the data provided by such Party pursuant to paragraphs 6(a)(5), *New Firm Resources*, ***6***(a)(6), *Firm Resource Retirements***,** and 6(a)(7), *Removal of Firm Resources*.

The Coordinating Group shall use Exhibit D, *Coordinated System's Firm Resources as of June 18, 1997,* as revised pursuant to this paragraph 6(b)(1) to determine FLCC.

(2) Determination of Critical Period

Determine the Critical Period using the data provided by the Parties pursuant to subsection 6(a), *Load and Firm Resource Data*.

(3) Shifting Limitations

Adjust the EAELs of the Coordinated System pursuant to method 6(b)-1., *Responsibilities of Study Group After Determination of Critical Period and Prior to Running the Preliminary Regulation*; *provided* the EAELs of individual Parties shall not be adjusted.

(c) Preliminary Regulation

Using the following criteria, the Coordinating Group shall run a Preliminary Regulation not later than March 15 of each Operating Year in order to determine a preliminary maximum Critical Period Energy Capability for the Coordinated System.

(1) Limitations for the Preliminary Regulation

Except as set forth in subsections 8(a), *Maintenance*, and 8(c), *Energy Reserve*, base the Preliminary Regulation on the utilization of all Firm Resources.

(A) Utilization of All Hydroelectric Firm Resources

Except as set forth in clauses 6(c)(1)(A)(i), 6(c)(1)(A)(ii), and 6(c)(1)(A)(iii) below, assume that each reservoir in the Coordinated System is at its normal top elevation at the beginning of the Critical Period and is drafted to its normal bottom elevation by the end of the Critical Period. Assume that the release of Treaty Storage in each Period is consistent with the most recent Treaty operating plan described in subsection 22(a), *United States-Canada Operating Plans*.

(i) Limitation of Reservoir Draft

Assume that no reservoir shall be drafted below the point where there is a net loss of Critical Period Energy Capability to the Coordinated System.

(ii) Limitation of Reservoir Operations to Accommodate Non-power Requirements

Base the regulation on the maximum use of storage water subject to Project non-power requirements.

(iii) New Reservoirs

When a new reservoir is to be included in the regulation, use the estimate of the reservoir's expected elevation for the July 31 preceding the first Critical Period in which such reservoir is included pursuant to this Agreement as a Firm Resource of such Reservoir Party which the Reservoir Party shall provide to each of the other Parties.

(B) Percent Outflow Limit

Limit the plant factor of each Project in any Period to the higher of (i) 85 percent, or (ii) the plant factor for an individual Project that is necessary to make the most of the Coordinated System's available storage useable during the Critical Period.

(C) Multi-Year Critical Period Draft Limit

As of each March 31 in a multi-year Critical Period, limit each reservoir's draft to its Assured Refill Curve ("ARC") unless all other reservoirs have been drafted to their ARCs and additional draft is required to meet the Coordinated System's EAEL. If draft of the Cyclic Reservoirs to their ARCs would result in generation in excess of such EAEL, regulate the Cyclic Reservoirs above their ARCs and allocate the resulting amount of Storage Energy (calculated pursuant to Formula 6.1 below) to each Cyclic Reservoir not required to draft down to its ARC.

Formula 6.1

$$SE_{res} = (G_{arc} - EAEL_{cs})R_{full\text{-}arc}$$

Where,

SE_{res}	=	The Storage Energy, in megawatt months, to be allocated to each Cyclic Reservoir such that that reservoir will be operated above its March 31 ARC but will not be operated above its flood control rule curve.
G_{arc}	=	The Coordinated System's generation, in megawatt months, for March resulting from operating all reservoirs down to their March 31 ARCs.
$EAEL_{cs}$	=	The Coordinated System's EAEL, in megawatt months, for March.
$R_{full\text{-}arc}$	=	The ratio of (i) the Storage Energy equivalent of drafting a Cyclic Reservoir from full to its March 31 ARC to (ii) the sum of the Storage Energy equivalents of drafting the Cyclic Reservoirs from full to their March 31 ARCs.

(2) Distribution of Energy Over the Critical Period

To the extent possible within the hydroelectric capability of each Project and except as provided in subsection 6(b)(3), *Shifting Limitations*, and method 6(c)-1., *Establishing Initial Offset(s)*, adjust the operation of hydroelectric facilities to distribute uniformly among the Periods of the Critical Period any energy surpluses or deficits between the Critical Period Energy Capability and the Coordinated System's EAEL.

(d) Determination of Preliminary Critical Period Energy Capability

The Coordinating Group shall determine for each Party a preliminary Critical Period Energy Capability by adjusting for estimated Restoration the Critical Period Energy Capability reflected in the Preliminary Regulation for such Party.

(e) Identification of Problems in the Preliminary Regulation

The Coordinating Group shall identify and communicate any problems in the Preliminary Regulation pursuant to method 6(e)-1., *Communication of Problems in the Preliminary Regulation*.

(f) Modified Load and Firm Resource Data

Prior to April 1 of each Operating Year, each Party shall modify its February 1 load and Firm Resource data submitted pursuant to subsection 6(a), *Load and Firm Resource Data*, pursuant to the following.

(1) Reduction of Thermal

A Party may reduce the amount of thermal energy and capacity to be included in its Firm Resources to the extent such amount is surplus to that Party's Estimated Firm Load. Any reduction in thermal energy capability during the Critical Period shall either (i) be the same in each Period, or (ii) shall be distributed such that the thermal energy capability remaining after such reduction has the same shape as the Party's EAEL, unless in either case changes in thermal energy capability are required to support thermal peaking.

(2) Revisions to Firm Contracts With Others Outside the Coordinated System

A Party may revise data submitted pursuant to subsection 6(a), *Load and Firm Resource Data*, concerning firm contracts with others outside the Coordinated System.

(3) Revisions to Maintenance

A Party may revise its schedule of Maintenance Outages submitted pursuant to subsection 6(a), *Load and Firm Resource Data*, and may identify any resulting changes in peak and energy capability for the affected Period(s).

(4) Revisions to Load

Each Party shall (i) revise its EAEL so that its average EAEL during the Critical Period equals its preliminary Critical Period Energy Capability as determined pursuant to subsection 6(d), *Determination of Preliminary Critical Period Energy Capability*, and (ii) lower its Estimated Adjusted Peak Load ("EAPL") so that its peak load does not exceed its anticipated Firm Peak Load Carrying Capability ("FPLCC") in any Period. Subject to the above requirements and so long as such revision does not, in the determination of the Coordinating Group, exacerbate a problem identified in the Preliminary Regulation and communicated to the Parties under method 6(e)-1., *Communication of Problems in the Preliminary Regulation*, a Party may revise its EAEL and EAPL in any Period for any reason; *provided* a Surplus Party shall not submit EAELs that would show a deficit in any Period in the Critical Period and a Deficit Party shall not submit EAELs that would show a surplus in any Period in the Critical Period.

(5) Forced Outage Rates

Each Party shall submit a Forced Outage Rate for each unit of its Firm Resources using the methodologies specified in clause 8(b)(3)(A)(ii), *Forced Outage Rates*. Until a Party submits a Forced Outage Rate for each unit of each of its Firm Resources, or if a Forced Outage Rate submitted by a Party pursuant to this paragraph 6(f)(5) is inconsistent with the Forced Outage Rate submitted for such unit pursuant to clause 8(b)(3)(A)(ii), *Forced Outage Rates*, the Coordinating Group shall, for purposes of this section 6, set the capacity of such unit equal to zero.

(g) Adjustment of Estimated Adjusted Energy Loads Prior to Running the Modified Regulation

The Coordinating Group shall adjust the respective EAELs of the Coordinated System and of each of the Parties pursuant to method 6(g)-1., *Responsibilities of the Study Group Prior to Running the Modified Regulation*.

(h) Modified Regulation

The Coordinating Group shall run a Modified Regulation and, in doing so, shall perform the following actions in the order set forth below.

(1) Running the Modified Regulation

After April 1 of each Operating Year, the Coordinating Group shall run a Modified Regulation using the load and Firm Resource data used by the Coordinating Group to run the Preliminary Regulation, as such data has been modified and adjusted by the Parties pursuant to subsection 6(f), *Modified Load and Firm Resource Data*, in order to determine a modified maximum Critical Period Energy Capability for the Coordinated System. The Coordinating Group shall run the Modified Regulation in an effort to accomplish the following in the priority listed below with subparagraph 6(h)(1)(A) being the highest priority.

(A) Distribution of Energy Over the Critical Period

Except as provided in paragraph 6(f)(4), *Revisions to Load*, and insofar as possible, any energy surpluses or deficits between the Critical Period Energy Capability and the Coordinated System's EAEL shall be distributed uniformly among the Periods of the Critical Period pursuant to method 6(h)-1., *Re-establishing Initial Offset(s)*. The Coordinating

Group shall run the Modified Regulation in each Period of the Critical Period based on the Coordinated System's EAEL adjusted for any Offset(s). For the Critical Period, the day-weighted average of all Offsets shall equal the difference between the average Coordinated System's EAEL and its average energy capability.

(B) Limit Non-useable Energy

Limit the amount of non-useable energy from the Coordinated System to no more than the amount of non-useable energy from the Coordinated System used in the Preliminary Regulation.

(C) Limit Draft in Multi-Year Critical Periods

As of each March 31 in a multi-year Critical Period, no reservoir shall be drafted below its ARC unless all other reservoirs have been drafted to such elevations and additional draft is required to meet the Coordinated System's EAEL. If draft of the Cyclic Reservoirs to such elevations would result in generation in excess of such EAEL, Cyclic Reservoirs shall be regulated above such elevations and the amount of retained Storage Energy (calculated pursuant to Formula 6.1 in subparagraph 6(c)(1)(C), *Multi-Year Critical Period Draft Limit*) shall be allocated to each Cyclic Reservoir not required to draft down to its ARC.

(D) Limit Plant Factor

Limit the plant factor of each Project in any Period to the higher of (i) 85 percent, or (ii) the plant factor for an individual Project that is necessary to make the most of the Coordinated System's available storage useable during the Critical Period.

(E) Adjust Firm Resources to Estimated Adjusted Energy Load

After adjusting average energy capability of the Coordinated System for energy reserves and estimated Restoration, adjust each Party's Firm Resources to equal its EAEL for the portion of each Operating Year in the Critical Period.

(F) Minimize Head Loss

Minimize loss of Critical Period Energy Capability to the extent that drafting storage water reduces head and results in a loss of the Coordinated System's Critical Period Energy Capability.

(2) Determination of Critical Period Energy Capability

The Coordinating Group shall determine for each Party a modified Critical Period Energy Capability by adjusting for estimated Restoration the Critical Period Energy Capability reflected in the Modified Regulation for such Party.

(3) Adjustments for Non-shapeable Energy Capability

In the event that the Coordinated System's energy capability cannot be reduced sufficiently in any Period of the Critical Period to meet that Period's Coordinated System's EAEL and corresponding Offset, the Coordinating Group shall adjust the EAELs of all Indicated Exporting Parties in that Period according to Formula 6.2 below.

Formula 6.2

$$EAEL'_{ies} = EAEL_{ies} + (O_{per} + NSEC)R_{iss}$$

Where, for each Period with Non-shapeable Energy Capability,

$EAEL'_{ies}$ = The adjusted EAEL, in average megawatts, of the Indicated Exporting Party from the Modified Regulation.

$EAEL_{ies}$ = The initial EAEL, in average megawatts, of the Indicated Exporting Party from the Modified Regulation.

O_{per} = The Offset, in average megawatts, for the applicable Period.

NSEC = The Non-shapeable Energy Capability, in average megawatts.

R_{iss} = The ratio of (i) the Indicated Exporting System's export to (ii) the total of all Indicated Exporting Parties' exports, both in average megawatts, where the export is the difference between the Indicated Exporting Party's energy capability, adjusted for estimated Restoration and energy reserves, and its EAEL.

Any increase in the EAEL of a Party made pursuant to this paragraph 6(h)(3) shall not be subject to adjustments pursuant to paragraph 6(h)(5), *Final Adjustments to Balance Parties' Loads and Firm Resources*.

(4) Adjustments to Uniformly Distribute Energy Surpluses or Deficits

Pursuant to method 6(h)-2., Reductions to the Party's(Parties') Estimated Adjusted Energy Load for Insufficient Generation After the Modified Regulation is Run, the Coordinating Group shall reduce the EAEL of each of the Parties in Periods not containing Non-shapeable Energy Capability in order to create a uniform surplus or deficit over the Critical Period for those Periods.

(5) Final Adjustments to Balance Parties' Loads and Firm Resources

For all Periods in which EAELs have not been adjusted pursuant to paragraph 6(h)(3) above, the Coordinating Group shall adjust each Party's EAEL according to Formula 6.3 below.

Formula 6.3

$$A'_{6.3} = (EC_{mr} + Restor - EAEL_{adj})R_{days}$$

Where, in each Period,

$A'_{6.3}$ = The adjustment, in average megawatts, to be made to a Party's EAEL.

EC_{mr} = The Critical Period Energy Capability, in average megawatts, established in the Modified Regulation for such Party.

Restor = The estimated Restoration, in average megawatts, for such Party.

$EAEL_{adj}$ = The Critical Period average EAEL, in average megawatts, for such Party, as adjusted pursuant to paragraph 6(h)(3), *Adjustments for Non-shapeable Energy Capability*, or 6(h)(4), *Adjustments to Uniformly Distribute Energy Surpluses or Deficits*.

R_{days} = The ratio of (i) days in the Critical Period to (ii) the total days in Periods not containing Non-shapeable Energy Capability.

(6) Determination of Firm Load Carrying Capability

The Coordinating Group shall determine each Party's FLCC from the Modified Regulation in accordance with subparagraphs 6(h)(6)(A) and 6(h)(6)(B) below.

(A) Determination of Firm Energy Load Carrying Capability

The Firm Energy Load Carrying Capability ("FELCC") of each Party for any Period shall be that Party's EAEL submitted pursuant to paragraph 6(a)(1), *Load Data*, as revised pursuant to paragraph 6(f)(4), *Revisions to Load*, and as adjusted sequentially pursuant to paragraphs 6(h)(3), *Adjustments for Non-shapeable Energy Capability*, 6(h)(4), *Adjustments to Uniformly Distribute Energy Surpluses or Deficits*, and 6(h)(5), *Final Adjustments to Balance Parties' Loads and Firm Resources.*

(B) Determination of Firm Peak Load Carrying Capability

The Coordinated System's FPLCC in each Period of the Critical Peaking Period shall be the sum of the computed Peaking Capabilities of each of the Parties, as derived from the Modified Regulation as set forth below and in the following order.

(i) Determination of Peaking Capability for Periods of the Operating Year

In order to determine the peaking capability of the Coordinated System for each Period of the Operating Year, the Coordinating Group shall do the following.

(a) Peaking Capability for the Highest Peak Load

Identify the Period (or consecutive Periods) in the Operating Year with the Coordinated System's highest EAPL. The computed Peaking Capability for such Period(s) shall be the average of the beginning and ending Peaking Capabilities for such Period(s) in the Modified Regulation. The Coordinating Group shall use the same methodology to determine the Peaking Capability for the Period immediately preceding and for the Period immediately succeeding the Period(s) with the Coordinated System's highest EAPL.

(b) Peaking Capability for the Lowest Peak Load

Identify the Period (or consecutive Periods) in the Operating Year with the Coordinated System's lowest EAPL. The computed Peaking Capability for such Period(s) shall be the average of the beginning and ending Peaking Capabilities for such Period(s) in the Modified Regulation. The Coordinating Group shall use the same methodology to determine the Peaking Capability for the Period immediately preceding and for the Period immediately succeeding the Period(s) with the Coordinated System's lowest EAPL.

(c) Peaking Capability for Increasing Loads

Identify each remaining Period in the Operating Year in which the amount of the Coordinated System's EAPL is (i) greater than the immediately preceding Period's Coordinated System's EAPL, and (ii) less than the immediately succeeding Period's Coordinated System's EAPL. The computed Peaking Capability for such identified Period shall be equal to the Peaking Capability computed in the Modified Regulation for the end of such identified Period.

(d) Peaking Capability for Decreasing Loads

Identify each remaining Period in the Operating Year in which the amount of the Coordinated System's EAPL is less than the immediately preceding Period's Coordinated System's EAPL and greater than the immediately succeeding Period's Coordinated System's EAPL. The computed Peaking Capability for such identified Period shall be equal to the Peaking Capability computed in the Modified Regulation for the beginning of such identified Period.

(e) Peaking Capability in Other Cases

Identify each Period in the Operating Year for which the Peaking Capability has not been determined pursuant to subclause 6(h)(6)(B)(i)*(a)*, 6(h)(6)(B)(i)*(b)*, or 6(h)(6)(B)(i)*(c)* above. For each such identified Period the computed Peaking Capability shall be equal to the average of the Peaking Capabilities computed for the beginning and the end of such identified Period in the Modified Regulation.

(f) Adjustments for Maintenance Outages and Forced Outage Reserves

Reduce the computed Peaking Capability for all Periods referenced in subclauses 6(h)(6)(B)(i)*(a)*, 6(h)(6)(B)(i)*(b)*, 6(h)(6)(B)(i)*(c)*, and 6(h)(6)(B)(i)*(d)* above for scheduled Maintenance Outages and Forced

Outage Reserves determined pursuant to subsection 8(b), *Forced Outage Reserves*.

(ii) Determination of Critical Peaking Period Average Firm Peak Load Carrying Capability for Each Party

The Coordinating Group shall determine the Critical Peaking Period in accordance with paragraph 8(b)(2), *Determination of Forced Outage Reserves*. The Coordinating Group shall determine each Party's Critical Peaking Period average FPLCC (i) by adding the Peaking Capability for such Party computed pursuant to clause 6(h)(6)(B)(i), *Determination of Peaking Capability for Periods of the Operating Year*, for the Periods of the Critical Peaking Period and (ii) then by dividing that sum by the number of Periods in the Critical Peaking Period.

(iii) Determination of Each Party's Firm Peak Load Carrying Capability for Each Period

The Coordinating Group shall determine each Party's FPLCC in each Period of the Operating Year (i) by adding such Party's EAPL for that Period to its Critical Peaking Period average FPLCC and (ii) then by subtracting each Party's Critical Peaking Period average EAPL from that sum; *provided* the FPLCC of a Party in any Period not included in the Critical Peaking Period shall not exceed the maximum Peaking Capability for such Party computed pursuant to clause 6(h)(6)(B)(i), *Determination of Peaking Capability for Periods of the Operating Year*, for such Period.

(iv) Adjustments to Maintenance Outages

Each Party shall reschedule Maintenance Outages to decrease the number of Periods in the Critical Peaking Period, to the extent that such rescheduling is reasonably practicable and would not cause another Period to become part of the Critical Peaking Period. The Coordinating Group shall, pursuant to this subparagraph 6(h)(6)(B), re-compute the Critical Peaking Period and the FPLCC of each of the Parties after any rescheduling of Maintenance Outages.

(v) Determination of Peak Deficient Parties

A Party shall be considered peak deficient for purposes of subsection 6(i), *Adjustments to the Modified Regulation*, if its FPLCC is either less than its EAPL in any Period of the Critical Peaking Period or if its FPLCC is greater than its computed

Peaking Capability computed pursuant to clause 6(h)(6)(B)(i) above in any other Period.

(i) Adjustments to the Modified Regulation

Not later than May 15 of each Operating Year, each Reservoir Party may, in order to obtain an optimum regulation for its System and subject to the limitations set forth in this subsection 6(i), make adjustments in (each of) its reservoir's(s') regulation(s) determined in the Modified Regulation for the next Operating Year. Such adjustments shall be made sequentially by Period beginning at the start of the Critical Period and continuing through the last Operating Year of the Critical Period.

(1) Adjustment Limitations

No Party shall adjust its reservoir's(s') regulation(s) under this paragraph 6(i)(1) in a manner that results in any of the following.

(A) Loss of Useable Generation

A loss of the Coordinated System's useable generation during the Critical Period through (i) increase in total spill of water, (ii) increase in uncontrollable generation (*i.e.*, energy capability less all energy reserves in excess of the EAEL in any Period), or (iii) inability to draft all storage water to end-of-Critical Period elevations.

(B) Change to April 1 Reservoir Elevations

A change to any reservoir elevation as of April 1 of each year of the Critical Period from such April 1 elevation determined in the Modified Regulation.

(C) Increases in Indicated Imports or Exports

An increase in its Indicated Import or Indicated Export of energy in any Period, except as provided in paragraph 6(i)(4), *Designation of Holding Energy*.

(D) Reductions in Indicated Imports or Exports

A reduction in its Indicated Import or Indicated Export of energy in any Period, if such reduction is in an amount greater than such Indicated Import or Indicated Export, respectively.

(E) Reduction in Storage Drafts for the Return of Holding Energy

A reduction of storage draft in a reservoir designated as receiving Holding Energy ("HE"), if such reduction is in an amount greater than the amount of draft required to return the HE.

(2) Implementation of Adjustments

A Reservoir Party shall only make adjustments that can be accommodated by the other Reservoir Parties as follows. When a Reservoir Party makes an adjustment in any of its reservoirs' regulations, each of the other Reservoir Parties shall, to the extent permitted by the above limitations and within its reservoir(s) operating requirements, make corresponding adjustments in (each of) its reservoir's(s') regulation(s) so that the Coordinated System's energy capability, less all energy reserves, equals the EAEL of the Coordinated System in every Period. Such adjustments shall be prorated among the Reservoir Parties in proportion to their Indicated Import or Indicated Export of energy as determined in the Modified Regulation.

Each Reservoir Party shall make all necessary compensating adjustments such that (each of) its reservoir(s) shall be at the elevations indicated in the Modified Regulation for April 1 of each year of the Critical Period or, if such Critical Period ends in the Operating Year for which such adjustments apply, by the end of the Critical Period.

(3) Priority of Adjustments

Adjustments shall be allowed in the priority listed below with subparagraph 6(i)(3)(A) being the highest priority.

(A) Peak Deficient Parties

Any Party having a peak deficiency under the Modified Regulation, if the adjustment would reduce its Indicated Exports of energy during the Period under consideration and reduce or eliminate its cumulative Indicated Exports of energy from the start of the Critical Period through the Period or Periods of its peaking deficiency.

(B) Importing Parties

Any Party, if the adjustment would reduce or eliminate its Indicated Import of energy during the Period under consideration.

(C) Exporting Parties

Any Party, if the adjustment would reduce or eliminate its Indicated Export of energy during the Period under consideration.

If adjustments are requested by more than one Reservoir Party, requests shall be addressed in the order of priority specified above. If fewer than all requests in one order of priority can be accommodated, the requests in that priority shall be met pro rata, based upon the ratio of (i) the energy equivalent of each request to (ii) the total energy equivalent of all requested adjustments, and the requests of lower orders of priority shall not be addressed.

(4) Designation of Holding Energy

If any Reservoir Party is precluded by paragraph 6(i)(1), *Adjustment Limitations*, from adjusting the regulation(s) of (each of) its reservoir(s) to reduce or eliminate the Indicated Import of energy to its System in the first two Periods of the Critical Period, that Reservoir Party may designate a part or all of the remaining import in those Periods as HE. In response, each Party having an Indicated Export may designate a part or all of its Indicated Export of energy available in those Periods as HE.

If any Party with an Indicated Export in a Period elects not to designate part or all of its Indicated Export of energy as HE, that Party shall increase its EAEL in that Period in an amount equivalent to that amount of its Indicated Export of energy that such Party elected not to designate as HE and shall correspondingly decrease its EAEL in Periods between the third Period of the Critical Period and the following March.

If a Party designates a part or all of its Indicated Exports of energy as HE, the following shall apply. Prior to making adjustments to reduce the draft from the designated reservoirs of an Indicated Importing Party who desires to draft, the affected Parties shall prepare a schedule that shows the amounts and Period(s) of HE transfers and the reservoir(s) designated by the Indicated Importing Party involved in the transfers. In the event the affected Parties cannot agree on such a schedule, a schedule shall be created by the affected Parties that requires the return of HE as soon as possible after the second Period of the Critical Period in an amount that is equal to the least of: (i) the Indicated Importing Party’s Indicated Export; (ii) the Indicated Exporting Party’s Indicated Import, or (iii) the amount available for return from the designated reservoir(s). Schedules shall in any case provide for return of all HE before the April 1 following delivery.

Subject to the limitations set forth in paragraph 6(i)(1), *Adjustment Limitations*, the Indicated Importing Party may re-regulate any of its reservoirs, and shall re-regulate any designated reservoir(s) upon the request of the Indicated Exporting Party, to increase the scheduled return of HE to the extent that the Indicated Exporting Party can store or otherwise use such scheduled return on its own System. In the event that the total available Indicated Exports exceed the total HE designated by the Reservoir Party(ies) from its(their) Indicated Imports, then such exceedence shall be prorated among the original Indicated Exporting Parties to the extent such Parties are still Indicated Exporters, based upon such original Indicated Exports.

Reservoirs of the importing Systems designating HE shall be re-regulated to produce on the importing System the energy designated by it but not made available to it as HE.

(5) Final Adjustments for Head Losses and Gains

Following any reservoir re-regulation under this subsection 6(i), the Parties shall adjust their EAELs and EAPLs to reflect the increases or decreases in Firm Resources in their Systems caused by changes in hydroelectric plant heads.

(j) Final Regulation

Not later than July 1 of each Operating Year, the Coordinating Group shall prepare a Final Regulation incorporating all permissible adjustments pursuant to this Agreement. Following the procedures set forth in paragraph 6(h)(6), *Determination of Firm Load Carrying Capability*, the Coordinating Group shall use the resulting-final Critical Period Energy Capability, after adjustments for Restoration, to determine each Party's FLCC.

(k) Determination of Restoration

The purpose of Restoration is to compensate Reservoir Parties for decreases in their FELCCs caused by the inclusion of Treaty Storage. Each Restoration Project has a right to carry at least the same firm energy load with Treaty Storage as it would have without inclusion of such storage. To accomplish this, all Projects whose ability to carry firm energy load is increased as a result of inclusion of Treaty Storage shall provide a portion of this increased ability to Restoration Projects whose ability to carry firm energy load has been decreased as a result of inclusion of Treaty Storage.

As soon as possible, the Coordinating Group shall run a Restoration regulation based upon all data in the Final Regulation except that Treaty Storage shall be excluded and the Estimated Firm Energy Load (“EFEL”) of the Coordinated System shall be used. When the Critical Period for the Final Regulation is less than one year, the EFEL shall include only firm load within the geographical area specified in the definition of System. In such regulation, the Coordinated System’s EFEL shall be adjusted by a uniform percentage in each month in order to balance the loads as adjusted with the Coordinated System’s Critical Period Energy Capability without Treaty Storage. If the Critical Period without Treaty Storage is shorter than seven months, a new regulation without Treaty Storage shall be run using the seven months September through March as the Critical Period.

(1) Determination of Gains and Losses

For each Restoration Project the Coordinating Group shall determine the amount of gain or loss for the Critical Period according to Formula 6.4 below.

Formula 6.4

$Q = P_w - (S_w/S_{w/o})P_{w/o}$

Where,

Q	=	Restoration Project gain or loss, in average megawatts; *provided* the amount of any loss shall not exceed the Restoration Project's "Restoration-Limit Megawatts" set forth in Exhibit E, *Limits of Rights to Restoration*.
P_w	=	Critical Period Energy Capability, in average megawatts, of each Restoration Project from the Final Regulation (with Treaty Storage) after adjustment for tailwater encroachment.
$P_{w/o}$	=	Critical Period Energy Capability, in average megawatts, of each Restoration Project from the Restoration Regulation (without Treaty Storage) after adjustment for tailwater encroachment.
S_w	=	Average EFEL, in average megawatts, of the Party that includes the Restoration Project in its Firm Resources for the Critical Period determined with Treaty Storage.
$S_{w/o}$	=	Average EFEL, in average megawatts, of the Party that includes the Restoration Project in its Firm Resources for the Critical Period determined without Treaty Storage and for all repetitions of such Critical Period included in the Critical Period with Treaty Storage.

(2) Equalization of Gains and Losses

The gain for Restoration Projects with a positive Q value shall be revised and redistributed to Restoration Projects with a negative Q value according to Formula 6.5 below.

Formula 6.5

$$Q' = (Q)R_{lg}$$

Where,

Q' = The revised Restoration Project gain, in average megawatts.

Q = The gain, in average megawatts, determined for the Restoration Project pursuant to the paragraph 6(k)(1) above.

R_{lg} = The ratio of all Restoration Project losses, to all Restoration Project gains, both in average megawatts, determined in paragraph 6(k)(1) above.

(3) Determination of Restoration by Party

The net amount of Restoration to be supplied by or to each Party shall be the algebraic sum of Q′ as determined in the preceding paragraph 6(k)(2) for each Restoration Project in that Party's System. Each Party shall adjust its energy capability in each Period by the amount of net Restoration determined under this paragraph 6(k)(3).

(l) Determination of Critical Rule Curves

The Coordinating Group shall establish Critical Rule Curves ("CRC") by July 1 of each year based upon reservoir drafts determined under subsection 6(j), *Final Regulation*. The CRCs for the next Operating Year shall reflect the reservoir drafts indicated for such Operating Year from all prior Final Regulations that included any part of such Operating Year in its Critical Period. The CRCs shall be ordered and designated by number (*i.e.*, first, second, etc.) on the basis of the decreasing Coordinated System's Storage Energy indicated by such CRCs at the beginning of such Operating Year. The CRCs for each reservoir shall be identified in feet of elevation as of the end of each Period of such Operating Year.

(m) Establishment of Firm Load Carrying Capability

Not later than August 1 of each Operating Year, the Coordinating Group shall establish the FLCC of each Party most recently calculated under subsection 6(j), *Final Regulation*; *provided* if the Coordinated System fails to reach 98 percent of its total Storage Energy by the end of July of the preceding Operating Year, as soon as practicable after August 1 of the current Operating Year the FLCC of each Party shall be re-established retroactively using the following procedures.

(1) Determination of Coordinated System Storage Energy

The Coordinating Group shall compute the Storage Energy of the Coordinated System for each Final Regulation that contains part or all of the current Operating Year within the Critical Period. To make this computation, the Coordinating Group shall convert the storage content of each reservoir as of the end of the previous Operating Year to its Coordinated System energy equivalent and total the resulting energy equivalents.

(2) Determination of Percent Full

The Coordinating Group shall compare the amount(s) of total Storage Energy computed in paragraph (1) of this subsection 6(m) to the Storage Energy for the preceding July 31 computed using procedure 9(b)-3., *Actual Energy Regulation*. The Coordinating Group shall establish the FLCC of each Party for the current Operating Year using the Final Regulation that most closely approximates the computed Storage Energy of the preceding July 31.

If procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, the Coordinating Group shall compare the amount(s) of total Storage Energy computed in paragraph (1) of this subsection 6(m) to the Storage Energy in the reservoirs of the Coordinated System as of the preceding July 31. The Coordinating Group shall establish the FLCC of each Party for the current Operating Year using the Final Regulation that most closely approximates the computed Storage Energy of the preceding July 31. If the actual Storage Energy is less than the lowest Storage Energy computed from the applicable Final Regulations, the Coordinating Group shall establish as the FLCC of each Party for the current Operating Year the FLCC of such Party for the current Operating Year computed using the Final Regulation with the lowest computed Storage Energy.

(n) Firm Energy Load Carrying Capability Outside the Critical Period

(1) Pre-Critical Period Firm Energy Load Carrying Capability

When FLCC is established using the first Operating Year of a Critical Period and the Critical Period commences after the beginning of such first Operating Year, the Coordinating Group shall employ either method 6(n)-1., *Development of Pre-Critical Period Firm Energy Load Carrying Capability for Critical Periods Longer than One Year*, or method 6(n)-3., *Development of Pre-Critical and Post-Critical Period Firm Energy Load Carrying Capability for Critical Periods Less Than One Year*, to establish each Party's FELCC for each Period occurring prior to the Critical Period.

(2) Post-Critical Period Firm Energy Load Carrying Capability

When FLCC is established using the final Operating Year of a Critical Period and the Critical Period ends before the end of such final Operating Year, the Coordinating Group shall employ either method 6(n)-2., *Development of Post-Critical Period Firm Energy Load Carrying Capability for Critical Periods Longer than One Year*, or method 6(n)-3., *Development of Pre-Critical and Post-Critical Period Firm Energy Load Carrying Capability for Critical Periods Less Than One Year*, to establish each Party's FELCC for each Period following the end of the Critical Period.

(o) Adjustments to Established Firm Load Carrying Capabilities

If the Parties re-establish their FELCCs under subsection 6(m), *Establishment of Firm Load Carrying Capability*, prior to August 16 of the current Operating Year, the Coordinating Group shall make the following adjustments to reflect the data submitted by the Parties in their subsection 6(a), *Load and Firm Resource Data*, submissions, as modified by their subsection 6(f), *Modified Load and Firm Resource Data*, submissions.

(1) Retirement of Firm Resources

Adjust for Firm Resources scheduled to be permanently taken out of service or abandoned before or during the Operating Year.

(2) Project Data

Update characteristics of Firm Resources to conform to current subsection 6(a), *Load and Firm Resource Data,* data submittals.

(3) New Firm Resources

Add Firm Resources not previously available.

(4) Purchases

Adjust for changes in firm purchases from outside the Coordinated System.

(5) New Non-power Requirements

Add or modify non-power requirements not reflected in studies or regulations used to establish FLCCs.

Upon making any of the above submitted adjustments, the Coordinating Group shall revise each Party's FLCC in each Period of the Operating Year to reflect any change in the capability of that Party's Firm Resources and any change in firm purchases for such Period. The Coordinating Group shall use a Load Determination Re-regulation to make these revisions pursuant to method 6(o)-1., *Load Determination Re-regulation Process*.

(p) Exchange of Firm Energy Load Carrying Capability

Two or more Parties may exchange FELCC so long as the Coordinated System's total FELCC remains unchanged in each Period.

Section 7. Determination of Base and Variable Energy Content Curves

Subject to this section 7, each Reservoir Party annually shall determine for (each of) its reservoir(s) Base Energy Content Curves ("Base ECC") and Variable Energy Content Curves ("VECC") that provide storage sufficient to allow the Coordinated System at all times to generate its Firm Energy Load Carrying Capability ("FELCC") under a recurrence of any streamflows in the Historical Period of Record. Base ECCs shall be expressed as reservoir elevations, in feet, for the end of each Period of the twelve-month period beginning on August 1.

(a) Assured Refill Curve

Each Reservoir Party shall determine an Assured Refill Curve ("ARC") for (each of) its reservoir(s) based upon the elevations necessary to refill such reservoir using the Refill Volume.

(b) Critical Period of One Year or Less

When the Critical Period is one year or less, each Reservoir Party shall determine the Base ECC for (each of) its reservoir(s) from end-of-Period elevations indicated in the Critical Rule Curve(s) ("CRC") from the Final Regulation and from additional data in accordance with this subsection 7(b), subject to recalculation as provided in subsection 7(d), *Variable Energy Content Curves*.

(1) Base Energy Content Curve for Annual Reservoir

Each Reservoir Party shall use as the Base ECC for (each of) its Annual Reservoir(s) the CRC for such reservoir from August 15 through the last Period included in the Critical Period. For Periods after the end of the Critical Period, the Reservoir Party shall distribute among Periods the water required to refill such reservoir using the same distribution of the Unregulated Streamflows used to determine Refill Volume.

(2) Base Energy Content Curve for Cyclic Reservoir

Each Reservoir Party shall use as the Base ECC for (each of) its Cyclic Reservoir(s) the CRC for such reservoir until the CRC represents the volume of water in the Refill Volume for the Periods remaining in the Operating Year for which the Coordinating Group is currently planning.

For the remainder of such Operating Year, the Reservoir Party shall develop a Base ECC for (each of) its Cyclic Reservoir(s) to fill the reservoir to normal top elevation by the end of such Operating Year. The water required to refill the reservoir shall be distributed among the remaining Periods using the distribution of the Unregulated Streamflows used to determine the Refill Volume.

(c) Critical Period Longer Than One Year

When the Critical Period is longer than one year, each Reservoir Party shall use as the Base ECC for (each of) its Cyclic Reservoir(s) at the end of each Period the higher of the ARC or the elevations calculated in the Final Regulation for the first year of the Critical Period which started in the current Operating Year. Each Reservoir Party shall use as the Base ECC for (each of) its Annual Reservoir(s) the CRC in the first year of the Critical Period.

(d) Variable Energy Content Curves

Each Reservoir Party shall determine VECCs for (each of) its Cyclic Reservoir(s) for the Periods in January through July of the current calendar year in accordance with the following procedures.

(1) Volume Inflow Forecasting Method

Not later than August 1 of each year, for Cyclic Reservoirs**,** each Reservoir Party shall supply to all other Parties the basic method used by such Reservoir Party for forecasting volume inflow into (each of) its reservoir(s). The basic forecast methods shall include methods for determining the probable volume inflow to each such reservoir and the volume inflow for an agreed-upon probability of occurrence (as described in the immediately succeeding sentence) for the periods from the first of each Period, January through July, through July 31. Unless otherwise agreed by the Coordinating Group, the forecasts used in this paragraph 7(d)(1) and in paragraph 9(f)(1), *Updating Variable Energy Content Curves*, shall provide a 95 percent probability that the actual volume inflow shall equal or exceed the forecasted volume inflow.

(2) Method to Determine Variable Energy Content Curves

Not later than August 1 of each year, each Reservoir Party shall supply to all other Parties VECCs for (each of) its Cyclic Reservoir(s). Such VECCs shall be based upon forecasted volume inflow, and shall be in the form of a table, equation, family of curves, or other form from which end-of-Period reservoir contents or feet of elevation for the period January through July of the current calendar year can be determined. The VECCs shall provide for drafts below the Base ECC in the amount by which the forecasted volume inflow is in excess of total requirements for refill of the reservoir, minimum discharge requirements, non-power requirements for water at site and upstream, and water required to refill at upstream reservoirs. The VECCs shall be such that all reservoirs return to normal top elevation by the end of the following July.

(3) Historical Streamflow Record

The Coordinating Group shall at least once each ten years update the Historical Period of Record with the available streamflows.

(4) Refill Regulations

(A) Trial Refill Regulation Based on Minimum Flow Variable Energy Content Curves

Not later than September 1 of each year or such other date as may be agreed upon by the Coordinating Group, the Reservoir Parties shall, using streamflows from the Historical Period of Record, run a Trial Refill Regulation for comparison with the Refill Regulation referred to in subparagraph 7(d)(4)(B) below. In these regulations, the Coordinated System's assumed reservoir elevations on August 1 of each of the historical years shall be the actual reservoir elevations as of August 1 of the current Operating Year. Each reservoir shall be regulated on the Base ECC or the VECC, whichever is lower, except that the reservoirs shall be regulated below such ECCs as provided in subsection 9(g), *Operation of Reservoirs Below Energy Content Curves and Critical Rule Curves*, if necessary to produce the FELCC of the Coordinated System. In determining VECCs after January 1 of each year, the forecasted Unregulated Streamflow volume for each reservoir for the applicable month shall be the actual historical Unregulated Streamflow reduced by the forecasting error with the agreed-upon probability referred to in paragraph 7(d)(1) above.

(B) Refill Regulation

The Reservoir Parties shall run a Refill Regulation for the reservoirs in the Coordinated System to determine whether there are possible adjustments to VECCs that would, after the development of FELCC, allow the Coordinated System to refill in 95 percent of the years in the Historical Period of Record. The Reservoir Parties shall analyze the Trial Refill Regulation to determine the number of years in which both (i) energy in excess of the Coordinated System's FELCC was produced in the January through July period, and (ii) the Storage Energy in reservoirs of the Coordinated System failed to refill on July 31.

For purposes of such determination as to refill, the Refill Criterion shall be used irrespective of the length of the Critical Period.

If the number of such years exceeds five percent of the number of years in the Historical Period of Record, each Reservoir Party shall raise the applicable VECCs of its reservoirs that failed to refill to the elevations needed to reduce the number of such years to be no more than five percent of the number of years in the Historical Period of Record. Such percentage shall be revised to reflect any change in the forecast probability referred to in paragraph 7(d)(1) above. Each Reservoir Party shall first raise its VECCs to the Base ECC. If that fails to reduce the number of such years to be no more than five percent of the number of years in that Historical Period of Record, each Reservoir Party shall raise its VECCs to the extent necessary to reduce the number of such years to be no more than five percent of the number of years in that Historical Period of Record. If adjustments can be made to such reservoirs of two or more Systems, each Reservoir Party shall adjust the VECCs of its reservoirs with an indicated energy generation in excess of its FELCC during those Periods in which adjustments are required to higher elevations in proportion to the amount of such excess generation. In the event such adjustments by such Reservoir Parties with excess Systems fail to reduce the number of years as required in this subparagraph 7(d)(4)(B), additional adjustments required to achieve such reduction shall then be made by each Reservoir Party to its reservoirs with VECCs.

(5) Adjustments to Historical Variable Energy Content Curves to Pass Refill Test

Not later than October 1 of each year, each Reservoir Party shall tabulate (each of) its reservoir(s)'s VECCs, as adjusted pursuant to subparagraph 7(d)(4)(B) above, as a function of forecasted volume inflow for each reservoir in feet of elevation for the end of each Period, January through July.

Section 8. Maintenance and Reserves

(a) Maintenance

Each Party shall submit in a timely fashion under subsection 6(a), *Load and Firm Resource Data*, a schedule for planned maintenance work on its System that might reduce its Peaking Capability or energy capability during the period pertinent to the determinations of Firm Load Carrying Capability ("FLCC") under section 6, *Determination of Firm Load Carrying Capability*, or the 24-month period commencing on the following August 1, whichever is longer. The Parties shall attempt to minimize the number and duration of Maintenance Outages in the Critical Peaking Period and in as many adjacent Periods as possible, and shall attempt to coordinate outages to create a uniform peak surplus or uniform peak deficit in all Periods. The Parties shall measure such surpluses and deficits for each Period by subtracting from the Peaking Capability of the Coordinated System the sum of the Estimated Adjusted Peak Load ("EAPL") of the Coordinated System, Forced Outage Reserves of the Coordinated System, and the effect of total scheduled Maintenance Outages. If any Party revises schedules as permitted in paragraph 6(f)(3), *Revisions to Maintenance*, and subclause 6(h)(6)(B)(i)*(f)*, *Adjustments for Maintenance Outages and Forced Outage Reserves*, such Party shall, in making such revisions, assume operation under the conditions that are to be used to determine the FLCC. Although the Parties retain discretion to schedule maintenance activities, each Party shall submit an adequate schedule of Maintenance Outages to protect its actual ability to produce its FLCC computed pursuant to section 6, *Determination of Firm Load Carrying Capability*.

(b) Forced Outage Reserves

The Parties shall maintain reserve capacity in the Coordinated System at a level sufficient to protect against the loss of load in an Operating Year with no greater probability than one day in ten years. The Coordinating Group shall determine the probability of such loss of load based upon characteristics of Peak Load variability and generating equipment Forced Outage Rates.

(1) Forced Outage Reserve Studies

Not later than May 15 of each Operating Year, the Coordinating Group shall make a Forced Outage Reserve study as described in this subsection 8(b) based on the Modified Regulation for use pursuant to subparagraph 6(h)(6)(B), *Determination of Firm Peak Load Carrying Capability*. Not later than July 1 of each Operating Year, the Coordinating Group shall make the study required to compute Forced Outage Reserves used in the determination of FLCC pursuant to subsection 6(j), *Final Regulation*.

(2) Determination of Forced Outage Reserves

The Coordinating Group shall determine the Forced Outage Reserve for each Party for each Period as follows.

(A) Coordinated System Peaking Capability

The Coordinating Group shall determine the Peaking Capability of the Coordinated System pursuant to clause 6(h)(6)(B)(i), *Determination of Peaking Capability for Periods of the Operating Year*, without deduction of Forced Outage Reserve, for each Period.

(B) Determination of Peak Load

The Coordinating Group shall determine a Peak Load for the Coordinated System that is uniformly greater or less than the EAPL for the Coordinated System in each Period such that the probability of load loss for the Operating Year is equivalent to one day in ten years.

(C) Determination of Critical Peaking Period

The Critical Peaking Period shall include (i) the Period in the succeeding Operating Year with the highest probability of load loss, and (ii) all other Periods in such Operating Year for which the probability of load loss is greater than or equal to one-tenth of the probability of load loss in the Period in (i).

(D) Determination of the Coordinated System's Forced Outage Reserve

For each Period in the Critical Peaking Period the Forced Outage Reserve of the Coordinated System shall be the difference between the Peaking Capability determined for such Period pursuant to subparagraph 8(b)(2)(A) above and the Peak Load for such Period determined pursuant to subparagraph 8(b)(2)(B) above. For all other Periods the Forced Outage Reserve of the Coordinated System shall equal the average of the Forced Outage Reserves of the Coordinated System for the Periods of the Critical Peaking Period.

(E) Allocation of Forced Outage Reserve

For each Period of the Critical Peaking Period the Coordinating Group shall allocate the Forced Outage Reserve of the Coordinated System to each Party hereto using the method described in Exhibit F, *Reserves*, and the quantity so allocated to a Party in a Period shall be such Party's Forced Outage Reserve for such Period. For all other Periods the Forced Outage Reserve of any Party shall be equal to the average of the Forced Outage Reserves of such Party for the Periods of the Critical Peaking Period.

(3) Determination of the Load Loss Probability Distribution

The Coordinating Group shall determine the load loss probability distribution by convolving the capacity loss probability distribution (computed in subparagraph 8(b)(3)(A) below) with the Peak Load probability distribution (determined in subparagraph 8(b)(3)(B) below) in accordance with probability mathematics detailed in Exhibit F, *Reserves.*

(A) Computation of Capacity Loss Probability Distribution

The Coordinating Group shall compute the capacity loss probability distributions considering the following.

(i) Peak Firm Resources

The resources to be included in such computations for each Party shall be its Firm Resources as defined in (i) and (ii) of the definition of Firm Resources, the thermal resources included pursuant to (iii) of such definition**,** and any generating resources located outside the Coordinated System that are designated by the owning Party and that, but for their location, would meet the requirements of the definition of Firm Resources.

(ii) Forced Outage Rates

Each Party may submit Forced Outage Rates for any of its generating units using the approved methodologies set out in method 8(b)-1., *Forced Outage Rates*. Each Party shall review such Forced Outage Rates annually and shall make any appropriate revisions in Exhibit G, *Forced Outage Rates*.

(iii) Default Forced Outage Rates

If a Party does not submit Forced Outage Rates for any of its units under clause 8(b)(3)(A)(ii) above, the Coordinating Group shall use the most recently submitted Forced Outage Rates for such generating unit(s). If any such unit has never had a forced outage rate submitted, the Coordinating Group shall set the capacity of such unit at zero.

(iv) Shared Resource

When any major resource referred to in subclause 8(b)(3)(A)(i) above is shared by a number of Parties on a pro rata basis and when the resource is operated so that the sharing Parties' loads are in some part served by such resource as if it were in fact within such Parties' utility responsibility areas, the effect of such resource on the capacity loss probability distribution for such Party shall be as described in Exhibit F, *Reserves*.

(v) Out of Area Capacity

The Coordinating Group shall treat capacity available to any Party on a firm basis from major interties with other areas as single sources of generation with appropriate Forced Outage Rates assigned thereto.

(B) Peak Load Probability Characteristics

The characteristics of the Peak Load probability distribution applicable to each Party shall be as given in Exhibit H, *Peak Load Characteristics*. Each Party shall review such characteristics every five years, or more often if necessary, and make any appropriate revisions.

(c) Energy Reserve

The energy reserve of a Party shall be the product of the firm energy capability of thermal plants included in its Firm Resources and the applicable Forced Outage Rates calculated under method 8(b)-1., *Forced Outage Rates*.

(d) Spinning Reserve

The purpose of the Spinning Reserve Requirement is to insure a degree of spinning reserve capability and diversity within the Coordinated System. The Parties recognize that tie line control requirements, transmission limitations, local standby reserves, and prudent operating practices may result in greater Spinning Reserves for some Parties than the Spinning Reserve Requirement hereafter specified.

Each Party shall maintain during the current Operating Year Spinning Reserves of not less than one per cent of its EAPL.

A Party may arrange with another system to supply all or part of its Spinning Reserve Requirement.

Part III. Operations

This part shall not come into effect until the August 1 following the Effective Date.

Section 9. Operating Procedures, Obligations, and Rights

(a) Use of Firm Load Carrying Capability and of Energy and Capacity in Excess of Firm Load Carrying Capability

Each Party may use its Firm Load Carrying Capability ("FLCC") for any purpose. Each Party may use any available excess power for any purpose to the extent that the Coordinated System's Actual Energy Capability ("AEC") or Actual Peaking Capability ("APC") exceeds the amount required to supply the Coordinated System's FLCC. For the purpose of this subsection 9(a): (i) "excess power" is a Party's excess capacity and excess energy; (ii) "excess capacity" is the amount by which a Party's APC, including its Interchange Capacity rights and excluding its Interchange Capacity obligations, exceeds its Firm Peak Load Carrying Capability ("FPLCC"); and (iii) "excess energy" is the amount by which a Party's AEC, including its Interchange Energy and Holding Energy ("HE") rights and excluding its Interchange Energy and HE obligations, exceeds the Party's Firm Energy Load Carrying Capability ("FELCC").

(b) Actual Energy Capability

The Parties shall use procedure 9(b)-3., *Actual Energy Regulation*, to calculate their AECs; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded pursuant to this Agreement, each Party shall determine and use its AEC as set forth in paragraphs 9(b)(1) and 9(b)(2) below.

(1) Adjustments to Actual Energy Capability

The AEC of a Party for a Period shall be determined within five business days after the end of such Period. The determination of AEC shall be based on the energy actually received under firm contracts and arrangements with systems outside the Coordinated System and actual energy generated from a Party's Firm Resources and then adjusted for any rights and obligations pursuant to this subsection 9(b), observing priorities for use of facilities set forth in subsection 9(h), *Priorities on Use of Facilities for Power*. Appropriate adjustments shall be made when applicable for Maintenance Outages, Forced Outages, energy capability of Firm Resources not used, In Lieu Energy, stored energy, Flexibility Adjustment Account ("FAA"), Provisional Energy, Interchange Energy, HE, energy reserves, and energy for secondary purposes. Such adjustments for rights and obligations shall observe the following procedures, when applicable: Forced Outages and Maintenance Outages not scheduled pursuant to subsection 6(a), *Load and Firm Resource Data*, and subparagraph 6(f)(3), *Revisions to Maintenance*, shall not reduce the capability of a Party's Firm Resources and shall, therefore, neither increase a Party's right to Interchange Energy nor decrease such Party's obligation to deliver Interchange Energy at any time from what such right or obligation would have been without the outages; adjustment for an FAA shall be made only for positive balances in such account; appropriate adjustments for Interchange Energy and HE received, delivered, or returned during the Period shall be made to determine any remaining obligation or right; appropriate reductions shall be made for storage water that has been drafted below the lowest elevation permitted under subsection 9(g), *Operation of Reservoirs Below Energy Content Curves and Critical Rule Curves*; appropriate reductions shall be made in a Period for energy generation utilized for secondary purposes, and not requested as Interchange Energy, that could not have been stored in Coordinated System reservoirs and that would have otherwise spilled; and any adjustment involving the conversion of water to energy capability shall be determined by application of the same plant characteristic data submitted and used in the determination of FELCC pursuant to section 6, *Determination of Firm Load Carrying Capability*.

(2) Estimated Actual Energy Capabilities

Estimates of each Party's AEC shall be used for operating purposes during each Period whenever rights or duties are to be determined currently based on AEC. The Party shall make estimates for the current Period or the remaining part of the current Period based on conservative forecasts from known conditions. Required adjustments on account of differences between AEC and such estimates for a Period shall be made after the Period.

(c) Delivery and Return of Holding Energy

(1) Requests for Holding Energy

This subsection 9(c) shall apply if the Parties establish a FLCC for the Coordinated System that is associated with schedules for HE pursuant to paragraph 6(i)(4), *Designation of Holding Energy*. The Supplying Party shall deliver to a Receiving Party in any Period the lesser of (i) the amount established pursuant to paragraph 6(i)(4), *Designation of Holding Energy*, (ii) the amount sufficient to keep the Receiving Party's reservoir(s) at (each of) its Energy Content Curve(s) ("ECC"), or (iii) the amount requested by the Receiving Party. The Receiving Party may require such delivery at a daily rate of up to 120 percent of the amount established pursuant to paragraph 6(i)(4), *Designation of Holding Energy*. The Supplying Party shall pay the Receiving Party pursuant to paragraph 14(e)(1), *Holding Energy Service Charge*.

(2) Conversion to Storage

To the extent that HE is about to be spilled from the reservoir into which it was imported, the Receiving Party shall convert such energy at no charge to energy stored under the provisions of paragraph 9(i)(1), *Regular Storage*, and shall refund to the Supplying Party a payment computed pursuant to paragraph 14(e)(3), *Refund Resulting from Conversion of Holding Energy to Storage*. If a reservoir has HE from more than one Supplying Party, the Receiving Party shall designate the amount of each Supplying Party's HE to be converted under this paragraph 9(c)(2). The converted energy shall be subject to the provisions of paragraphs 9(i)(1), *Regular Storage*, 9(i)(2), *Potential Spill Conditions*, and 14(g)(2), *Stored Energy and Holding Energy*, and subsection 14(e), *Holding Energy Charges*.

The Receiving Party's obligation to return HE shall be decreased by the amount of HE converted to stored energy, but the Supplying Party's remaining obligation to deliver HE shall not be increased.

(3) Return of Holding Energy

The schedule of HE returns established pursuant to paragraph 6(i)(4), *Designation of Holding Energy*, shall be decreased to equal the total amount of remaining HE. Within each Period the Supplying Party shall have a right to the return of any remaining HE in a daily amount up to 120 percent of the adjusted schedule. If the Supplying Party requests return of HE prior to its scheduled return, the Receiving Party shall comply with such request to the extent honoring such request does not require draft below the ECC at the reservoir involved. When the HE is returned, the Supplying Party shall pay to the Receiving Party the balance of cash payments owed under paragraph 14(e)(1), *Holding Energy Service Charge*.

(4) Uniform Hourly Schedules and Special Shaping

The Delivering Party may elect not to deliver HE on Peak Load Hours ("PLH") and shall pay a shaping fee to the Party receiving the HE in accordance with paragraph 14(e)(2), *Holding Energy Re-shaping Charges*. For those hours not excluded, the Delivering Party shall deliver the daily amount of HE uniformly.

(d) Interchange Energy

Each Party shall have a right under this Agreement to energy equivalent to its FELCC. Any Party with an Indicated Import may require the delivery of Interchange Energy from one or more Parties with an Indicated Export. Such delivery from any individual Party with an Indicated Export shall not exceed the lesser of (i) the remaining portion of the Indicated Import not being supplied by Interchange Energy, or (ii) the Indicated Export not being supplied to other Parties as Interchange Energy. All Parties shall use their AEC and take delivery of Interchange Energy or procure energy to meet the lesser of their Actual Adjusted Energy Load or FELCC. Interchange Energy may be supplied by any Party from FELCC in excess of its Actual Adjusted Energy Load. The Delivering Party may elect not to deliver Interchange Energy on PLHs. For those hours not excluded under the immediately preceding sentence, the Delivering Party shall deliver Interchange Energy uniformly.

Upon request, a Party with a net debit in its Interchange Energy account with a Delivering Party shall pay an interim cash advance to the Delivering Party. The Parties shall settle imbalances in Interchange Energy deliveries pursuant to subparagraph 9(d)(3)(D), *Settling Interchange Energy Imbalances*.

(1) Delivery of Interchange Energy

For each Interchange Energy request, the Supplying Party shall declare on which prescheduled day(s) of such delivery it shall provide Loaned Interchange Energy and on which prescheduled day(s) of such delivery it shall provide Regular Interchange Energy. Such declaration of a Supplying Party shall not be changed for that request.

(A) Loaned Interchange Energy

If Loaned Interchange Energy is accepted, clause 9(d)(3)(A)(ii), *Loaned Interchange Energy*, shall govern its return.

(B) Regular Interchange Energy

A Supplying Party whose incremental cost of supplying Interchange Energy is greater than the single price determined in paragraph 14(a)(3), *Determination of Regular Interchange Energy Rate*, may require the Receiving Party to attempt to obtain Regular Interchange Energy from another Party. A Receiving Party required to seek another source of Regular Interchange Energy shall, to the extent available and as time may permit, obtain such portion of Regular Interchange Energy from other Supplying Parties whose incremental cost of both producing or acquiring the Regular Interchange Energy is no greater than the single price. To the extent the Receiving Party is unable to obtain Regular Interchange Energy from alternative sources, the original Supplying Party shall satisfy the original request.

(C) Competing Requests for Interchange Energy

When the sum of Interchange Energy requests exceeds the obligation of the Supplying Party to deliver Interchange Energy, such Supplying Party may deliver the Interchange Energy to the Receiving Party(ies) of its choice.

(2) Over-receipt of Interchange Energy

When a Receiving Party receives more Interchange Energy than it has a right to during a Period, it shall return the excess amount if requested by a Delivering Party. The Parties shall determine excess receipts within ten days after the end of the Period or as provided in subprocedure 9(b)-3.B., *Use of Actual Energy Regulation to Determine Interchange Rights and Obligations*. A Delivering

Party may give notice to such Receiving Party within three business days after such determination requesting return of the excess Interchange Energy. Such excess shall be returned within 15 days or by the end of the current Period, whichever is later. If a Delivering Party does not elect to recall excess Interchange Energy, such energy shall be accounted for as Interchange Energy unless the Supplying Party and Delivering Party agree to treat an excess receipt of Interchange Energy as a return of HE.

(3) Return of Interchange Energy

(A) Determination of Obligation to Return

On demand a Receiving Party shall return Interchange Energy to a Supplying Party as follows.

(i) Interchange Energy/Receiving Party Excess

Interchange Energy shall be returned to the extent the Receiving Party's AEC is in excess of its FELCC.

(ii) Loaned Interchange Energy

Irrespective of the Receiving Party’s energy requirements, Loaned Interchange Energy shall be returned whenever the Supplying Party's AEC (excluding the use of thermally generated energy) is less than its FELCC.

(iii) Regular Interchange Energy/Supplying Party Deficit

Irrespective of the Receiving Party’s energy requirements, Regular Interchange Energy shall be returned whenever the Supplying Party's AEC is less than its FELCC.

A Receiving Party’s obligation(s) to return Interchange Energy on demand pursuant to this paragraph 9(d)(3) shall be limited on any hour by the amount by which the Receiving Party's Peaking Capability exceeds the capacity such Party is using for purposes of higher priority under subsection 9(h), *Priorities on Use of Facilities for Power*; *provided* the daily energy amount of return shall not be affected except as allowed in such subsection.

(B) Credit for Returns

When a Receiving Party returns Interchange Energy to a Supplying Party, the outstanding Interchange Energy imbalance between such Supplying Party and such Receiving Party shall be reduced. Returns of

Regular Interchange Energy by a Receiving Party shall be applied to its imbalance account on a "first-in, first-out" basis by megawatt hour, except returns of excess Regular Interchange Energy deliveries shall be applied to the Period when the excess energy was delivered. A return of Regular Interchange Energy shall reduce the charges for such imbalance by eliminating the charges per megawatt hour. Upon a return of Regular Interchange Energy, the Supplying Party shall refund any applicable interim cash payments.

(C) Accounting Responsibilities

The Supplying Party shall inform the Receiving Party on an on-going basis of the balance of outstanding Interchange Energy identified by the Operating Year of initial delivery, the charge associated with such Operating Year, and the amount of outstanding interim cash payments.

(D) Settling Interchange Energy Imbalances

The Parties shall settle Interchange Energy imbalances pursuant to subprocedure 9(d)-3.A., *Settlement of Imbalances*; *provided* if that subprocedure is rescinded pursuant to this Agreement, the Parties shall settle imbalances as follows. At the end of any Refill-hold Period when Coordinated System reservoirs reach the Settlement Criterion, any Loaned Interchange Energy return obligation as of July 31 of that calendar year shall terminate. The Receiving Party shall (i) credit interim cash advances received from the Supplying Party to Regular Interchange Energy imbalances, and (ii) pay the Supplying Party for any imbalances remaining as of July 31 of that calendar year pursuant to paragraph 14(a)(2), *Regular Interchange Energy Imbalances*. Upon such payment, the Receiving Party's obligation to return Regular Interchange Energy imbalances to the Supplying Party shall be discharged.

(e) Interchange Capacity

Each Party shall have a right under this Agreement to capacity equivalent to its FPLCC.

(1) Right to Interchange Capacity

Any Party whose APC is less than its FPLCC shall have a right to the amount of Interchange Capacity necessary to meet its FPLCC. Except as provided in paragraph 9(e)(2) below, any Party whose APC is in excess of its FPLCC shall supply Interchange Capacity, and any Party with capacity in excess of its Actual Adjusted Peak Load may supply Interchange Capacity.

(2) Capacity Calculation

The Parties shall account for Interchange Capacity service on a calendar week basis and the Receiving Party shall pay for it at the rate provided in subsection 14(c), *Interchange Capacity Imbalances*. Such payment shall be based on the maximum amount requested and delivered during any hour as Interchange Capacity; *provided* if the Supplying Party is subsequently unable during that calendar week to deliver Interchange Capacity as great as the rate at which Interchange Capacity was previously delivered during such week, the lower amount shall be the Interchange Capacity delivered during such calendar week.

(3) Return of Energy Associated with Delivery of Capacity

At the option of the Supplying Party, the Receiving Party shall (i) return energy received with the delivery of Interchange Capacity within seven days of such delivery during Light Load Hours at a rate not to exceed that of the delivery of such Interchange Capacity, or (ii) purchase such energy at the rate specified in paragraph 14(a)(2), *Regular Interchange Energy Imbalances*.

(f) Adjustment of Energy Content Curves

Pursuant to the following, each Reservoir Party shall update its Variable Energy Content Curves ("VECC") and then the Coordinating Group shall adjust the ECCs for non-power requirements and natural restrictions.

(1) Updating Variable Energy Content Curves

At the beginning of each Period from January through July or as soon thereafter as practicable, each Reservoir Party shall provide all other Parties with projections of (i) the ECC elevation of (each of) its Cyclic Reservoir(s) at the end of each Period during the remainder of the Operating Year, and (ii) (each of) its reservoir's(s') inflow forecast and underlying data. Each reservoir's ECC shall be the lower of its Base ECC or its VECC. To determine such ECC elevations the Reservoir Party shall use its forecast method submitted pursuant to paragraph 7(d)(1), *Volume Inflow Forecasting Method*, and the VECC specified in paragraph 7(d)(5), *Adjustments to Historical Variable Energy Content Curves to Pass Refill Test*; *provided* if the Reservoir Party reasonably determines that its forecasted elevations do not represent the planned operation as described in subparagraph 7(d)(4)(B), *Refill Regulation*, the Reservoir Party may deviate from the forecast method, the reservoir's VECCs, or both, to the extent necessary to incorporate such operation into the VECCs. Any Reservoir Party deviating from the procedures of paragraphs 7(d)(1), *Volume Inflow Forecasting Method*, and 7(d)(5), *Adjustments to Historical Variable Energy Content Curves to Pass Refill Test*, shall advise all other Parties in writing of the reasons therefor.

(2) Draft for Non-power Requirements

If to satisfy non-power requirements a Reservoir Party is required to operate its reservoirs below the ECC, the actual elevations of such reservoir shall be deemed to be the ECC for such reservoir.

(3) Operation Above Energy Content Curve Due to Natural Restrictions

If a reservoir's actual elevation exceeds its ECC only because of a natural restriction that limits the outflow of a reservoir and the Project controlling such reservoir is discharging water at its current maximum restricted rate, the actual elevation shall be deemed to be the ECC for such reservoir.

(g) Operation of Reservoirs Below Energy Content Curves and Critical Rule Curves

Procedure 9(g)-1., *Operation of Reservoirs Below Adjusted Energy Content Curves and Critical Rule Curves*, shall govern the operation of reservoirs below their respective ECCs and CRCs. If such procedure is rescinded pursuant to this Agreement, the following shall apply.

(1) Condition for Reservoir Draft Below Energy Content Curve

Except as provided in subsection 9(l), *Provisional Energy*, and paragraph 9(g)(2) below, no Reservoir Party shall draft any of its reservoirs below the ECC for such reservoir unless all of the following conditions exist.

(A) Reservoirs are at Energy Content Curve or Physical Limit

All reservoirs have been drafted within their physical limits to their respective ECCs.

(B) Firm Resources at Full Operation

Firm Resources are operating to the full extent they were submitted in section 6, *Determination of Firm Load Carrying Capability*, planning or the Party who owns, leases, or controls the Firm Resources replaces them with an equivalent amount of energy (i) from outside the Coordinated System, (ii) from its FELCC in excess of its Actual Adjusted Energy Load, or (iii) from another Party's FELCC in excess of that Party's Actual Adjusted Energy Load.

(C) Draft Necessary to Produce Firm Energy Load Carrying Capability

Further draft is necessary to produce the Coordinated System's FELCC.

(2) Reservoir Balancing

Each Reservoir Party may draft any of its reservoirs below the ECC for such reservoir subject to the following conditions; *provided* if reservoir-balancing drafts or drafts for storage in another entity's system or another Party's System affect downstream Projects, the Reservoir Party and such downstream Parties shall treat such drafts as Provisional Drafts under subparagraphs 9(l)(1)(C), *Production of Provisional Energy/Options to Retain Energy or Produce Energy for Return*, and 9(l)(1)(D), *Adjustment to Actual Elevations*.

(A) Reservoir Balancing Within a System

A Reservoir Party may exchange water between (or "balance") its reservoirs if it can demonstrate that (i) the water exchanged is equivalent in useable energy to the Coordinated System, and (ii) there is an equal or greater probability that its reservoirs will refill after the water is exchanged.

(B) Reservoir Balancing Between Systems

A Reservoir Party may draft any of its reservoirs down to the ARC for such reservoir to store the resulting energy, including related head losses, in a reservoir of another Reservoir Party so long as such energy can be returned and during such storage there is no greater risk of spill. Subsection 9(i), *Storage of Energy in Reservoirs*, shall govern such storage.

(3) Proportional Draft

When all reservoirs must be operated below their ECCs in order to produce the Coordinated System's FELCC, the Coordinating Group shall establish Proportional Draft Points ("PDPs") for Coordinated System reservoirs and each Reservoir Party shall operate (each of) its reservoir(s) to its PDP. PDPs shall result in Coordinated System reservoirs being drafted proportionately, expressed in elevation, between CRCs sequentially ordered pursuant to subsection 6(l), *Determination of Critical Rule Curves*. For purposes of this paragraph 9(g)(3), the normal bottom of the reservoir shall be an additional and the lowest CRC. If a Reservoir Party has lowered any of its reservoirs' ECC elevations for any Period below one or more of the reservoir's(s') CRC elevations under subsection 9(f), *Adjustment of Energy Content Curves*, such Reservoir Party shall lower the CRC elevations for such reservoir(s) that are above the ECC elevation to the level of the ECC elevation.

If a Reservoir Party is unable to draft any of its reservoirs to their PDP established above (i) without spilling water that reasonably could be used within the Critical Period, or (ii) because of outlet restrictions, discharge requirements, or operation for non-power requirements, such Reservoir Party shall operate (each of) such reservoir(s) as near as possible within such limitations to achieve its PDP established above, whereupon the Coordinating Group shall ratably adjust all other reservoirs' PDPs to produce the FELCC of the Coordinated System; *provided* a Reservoir Party may exchange storage water among the reservoirs of such Reservoir Party for the purpose of balancing such Party's reservoirs if such exchange does not affect adversely any downstream Project not owned or operated by such Party and if such Party can reasonably demonstrate such exchange results in equivalent useable energy and probability of refill.

(h) Priorities on Use of Facilities for Power

No Party shall be required to exceed the capabilities of physical facilities that are dedicated to coordination and are available for its use. If a Party reasonably determines that such capabilities will be exceeded because of a combination of (i) such Party's rights to FLCC under this Agreement, (ii) demands made under this Agreement, and (iii) such Party's performance of its obligations to provide power, energy, and transmission services, such Party shall use the capabilities of its facilities (including machine capacity, reservoir capacity, and transmission capacity) according to the priority listed below with paragraph 9(h)(1) being the highest priority. Once a Party determines that its capabilities will be exceeded because of a combination set forth above, each demand on such Party under this Agreement remaining unmet because of any such combination shall be deferred until such time as such Party determines that it has sufficient capabilities to satisfy such demand in the order of its priority. Multiple transactions falling within the same numbered category shall have the same priority.

(1) Firm Load Carrying Capability From Hydroelectric Firm Resources

The Party shall supply its FLCC from its own hydroelectric Firm Resources and shall use its transmission capacity to fulfill its own FLCC and to fulfill contracts for transmission services or for transmission services associated with such Party's power or energy contracts.

(2) Firm Load Carrying Capability From Other Firm Resources

The Party shall supply its remaining FLCC from its other Firm Resources.

(3) Interchange Capacity

The Party shall deliver Interchange Capacity under subsection 9(e), *Interchange Capacity*.

(4) Deliveries and Returns Needed to Support Others' Firm Energy Load Carrying Capability

When required to maintain the Requesting Party's(ies') FELCC, the Party shall deliver and return In Lieu Energy, deliver replacement energy under subparagraph 9(l)(1)(C), *Production of Provisional Energy/Options to Retain Energy or Produce Energy for Return*, and deliver energy under the refusal option pursuant to paragraphs 13(c)(2), *Return by Downstream Party Upon Release of Storage*, and 13(c)(3), *Return by Reservoir Party Upon Storage*.

(5) Return of Storage Needed to Support Others' Firm Energy Load Carrying Capability

When required to maintain the Requesting Party's(ies') FELCC, the Party shall return energy stored in reservoirs under subsection 9(i), *Storage of Energy in Reservoirs*.

(6) Interchange Needed to Support Others' Firm Energy Load Carrying Capability

When required to maintain the Requesting Party's(ies') FELCC, the Party shall deliver or return HE and Interchange Energy under subsections 9(c), *Delivery and Return of Holding Energy*, and 9(d), *Interchange Energy*.

(7) Any Other Purpose for Own Use

The Party shall supply any of its own requirements for other purposes.

(8) Interchange for Others' Use

The Party shall deliver and return HE and Interchange Energy under subsections 9(c), *Delivery and Return of Holding Energy*, and 9(d), *Interchange Energy*, to allow the Requesting Party(ies) to use it for any other purpose.

(9) Deliveries and Returns for Others' Use

The Party shall deliver and return In Lieu Energy, deliver replacement energy under subparagraph 9(l)(1)(C), *Production of Provisional Energy/Options to Retain Energy or Produce Energy for Return*, and deliver energy under the refusal option pursuant to paragraphs 13(c)(2), *Return by Downstream Party Upon Release of Storage*, and 13(c)(3), *Return by Reservoir Party Upon Storage*, to allow the Requesting Party(ies) to use it for any other purpose.

(10) Storage Returns for Others' Use

The Party shall return energy stored in reservoirs under subsection 9(i), *Storage of Energy in Reservoirs*, to the Requesting Party(ies) to use it for any other purpose.

(11) Provisional Energy Deliveries

The Party shall deliver energy produced from the release of water for the production of Provisional Energy under subparagraph 9(l)(1)(C), *Production of Provisional Energy/Options to Retain Energy or Produce Energy for Return*.

(12) Any Other Use

The Party shall use its discretion in delivering or returning energy to the Requesting Party(ies) for use for any other purpose.

(i) Storage of Energy in Reservoirs

(1) Regular Storage

A Supplying Party may store energy with any Reservoir Party to the extent that the Reservoir Party has space available in its reservoir(s). The Reservoir Party shall have discretion in the use of its storage space. A Reservoir Party receiving conflicting requests for storage space or return of stored energy shall also have discretion in determining how to meet the request(s) and, if spill occurs, whose energy was spilled. A Reservoir Party planning to displace stored energy shall notify the Supplying Party and shall endeavor to conserve the energy.

Each Reservoir Party shall account for the energy it stores, spills, or returns in megawatt hours. To compute the energy equivalent in megawatt hours of water spilled, the Reservoir Party shall use the average conversion factor (megawatts per thousand cubic feet per second) in effect at the time the water was spilled.

On demand, a Reservoir Party shall return to the Supplying Party any stored energy not purchased or spilled to the extent the Reservoir Party's available hydroelectric-generating capacity at the reservoir exceeds the generating capacity required for higher priority purposes under subsection 9(h), *Priorities on Use of Facilities for Power*. When releasing water to return stored energy the Reservoir Party shall decrease the Supplying Party's account for stored energy by the sum of the following quantities.

(A) Energy Returned

The amount of stored energy returned.

(B) Energy Spilled

The amount of energy spilled at the Reservoir Party's downstream Projects caused by the release.

(C) Credits for In Lieu Energy Spilled

The amount of the Reservoir Party's In Lieu Energy that is lost through spill credits at downstream Projects caused by the release of stored water.

Spill resulting from water released to return stored energy constitutes spill of stored energy. Charges and refunds for the foregoing shall be governed by subsection 14(f), *Stored Energy Service Charges*.

If a Reservoir Party generates energy with stored water and consequently spills an equivalent amount of energy elsewhere on its System or if that Reservoir Party transfers such energy to another Party for immediate spill, such energy shall be considered spilled energy.

When the reservoirs of the Coordinated System reach the Refill Criterion, a Reservoir Party may purchase any remaining energy stored in its reservoirs by a Supplying Party under this subsection 9(i) from such Supplying Party at the rate set forth for Interchange Energy imbalances in paragraph 14(a)(2), *Regular Interchange Energy Imbalances*.

(2) Potential Spill Conditions

During a Potential Spill Period the following subparagraphs 9(i)(2)(A) and 9(i)(2)(B) shall apply, except as to energy stored during any such Potential Spill Period. Such energy shall not be returned under subparagraph 9(i)(2)(A) below even if the spill occurs after the notice period expires.

(A) Imminent Spill

When a Reservoir Party notifies all other Parties who have stored energy in its reservoir that spill is imminent, the charges for any stored energy returned during such imminent spill condition shall be determined under paragraph 14(f)(4), *Charges in the Case of Imminent Spill*.

(B) Transfers to Avoid Spill

Upon the request of a Supplying Party, a Reservoir Party shall make reasonable efforts to transfer stored energy to avoid spill. If stored energy is so transferred to avoid spill, no Receiving Party shall impose a charge for transferring stored energy from its reservoir to another Party's reservoir. In such instances, the original Receiving Party shall retain the delivery charge received pursuant to paragraph 14(f)(1), *Delivery Charges*. The Supplying Party shall pay the return charges to the final

Receiving Party on return of the Supplying Party's stored energy under paragraph 14(f)(2), *Return Charges*. If stored energy is spilled after it is transferred, the original Receiving Party shall refund the charges collected on delivery pursuant to paragraph 14(f)(5), *Refund of Storage Charges when Storage is Spilled*.

When any energy a Reservoir Party accepts for storage during a Potential Spill Period is returned, the charges in paragraph 14(f)(2), *Return Charges*, shall apply or, if spilled, such spill shall be on a "last-stored, first-spilled" basis.

(j) Release of Water From Storage and In Lieu Energy Deliveries

(1) Provisions for Requested Releases

The owner of a downstream Project may request release of water accumulated above the ECC in an upstream reservoir. Upon such request, the upstream Reservoir Party either shall release such water or shall supply to the requesting downstream Project owner energy in lieu thereof in an amount equivalent to the energy that such water would have generated at the downstream Project if released. In Lieu Energy shall be scheduled such that receipt of such energy by the downstream Project owner will be neither more nor less advantageous to the downstream Project owner than if the water had been released. The downstream Project owner's receipt of In Lieu Energy vests in the Reservoir Party such owner's right to water corresponding to the In Lieu Energy and increases the amount of Assigned Water attributed to the downstream Project owner.

(2) Conservation of Energy

In any request for the release of water, the downstream Project owner shall use its best efforts to minimize spill. The Reservoir Party shall not be required to release water (or to deliver energy in lieu thereof) in excess of the generating capability of its reservoir Project unless the Reservoir Party's reasonable forecasts indicate that the reservoir would otherwise be above its ECC at the end of the Drawdown Period.

(3) In Lieu Energy Return

When the right of any downstream Project owner to water above the ECC at an upstream reservoir has been satisfied and Assigned Water is being released (*i.e.*, the reservoir's rate of release exceeds the rate indicated by the reservoir's ECC), the downstream Project owner shall return all incremental energy generated at its downstream Project from the release of such Assigned Water.

The energy shall be returned as it is generated from the Assigned Water release except in the following cases.

(A) Rate Limitation

When the rate of generation exceeds the energy equivalent of the difference between the reservoir's actual outflow and the reservoir's minimum release requirement, the downstream Project owner shall return the energy at the maximum allowable rate until such return obligation is satisfied.

(B) Adjustment for Natural Outflow Restrictions

When the ECC of a reservoir is adjusted because of a natural outflow restriction under paragraph 9(f)(3), *Operation Above Energy Content Curve Due to Natural Restrictions*, and the adjustment creates an obligation to return outstanding In Lieu Energy, a downstream Project owner with a return obligation shall make available to the Reservoir Party, in each of the five weeks following such adjustment, 20 percent of the energy owed.

(4) Termination and Reinstatement

During the portion of the year when the ECC indicates that an upstream reservoir is refilling, a downstream Project owner may, by giving notice to the Reservoir Party, suspend its right to request further release of water from the upstream reservoir until the end of the current Refill-hold Period. During such period, the downstream Project owner may, by giving notice to the Reservoir Party, designate any portion of the water released from the upstream reservoir in excess of minimum releases as Assigned Water releases up to the amount of its Project's remaining Assigned Water. The resulting return of In Lieu Energy shall be returned so as to conform to the return requirements in paragraph 9(j)(3) above. If the ECC is adjusted under paragraph 9(f)(1), *Updating Variable Energy Curves*, any right to request releases of water that had been suspended may be reinstated by the downstream Project owner by giving notice to the Reservoir Party when the adjusted ECC deviates from the previously designated ECC; *provided* after such reinstatement the downstream Project owner shall not again suspend its right until (i) it has made a request for a release of water at the reservoir, and (ii) seven days have elapsed since reinstatement.

(5) Requests of Mid-Columbia Projects for Release of Storage from Federal Projects Upstream of Chief Joseph Project

The rights and obligations of the Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapids Project owners arising from this subsection 9(j) with respect to those reservoirs upstream from Chief Joseph Project for which the United States is the Reservoir Party shall be implemented pursuant to procedure 9(j)-3., *In Lieu Energy Transactions for Federal Reservoirs and Mid-Columbia Projects*, so long as that procedure is in effect.

(6) Termination for the Last Year of the Agreement

During the last Operating Year of this Agreement any downstream Project owner may, by giving notice to the Reservoir Party, terminate its right to request releases of water from upstream reservoirs. Upon such termination, the downstream Project owner may, by giving notice to the Reservoir Party, designate any releases in excess of minimum as releases of Assigned Water up to the amount of its Project's remaining Assigned Water and, if such designation is made, the downstream Project owner shall return energy in accordance with paragraph 9(j)(3) above.

(7) Settlement When the Agreement Terminates

If any Assigned Water remains in a reservoir after termination of this Agreement, the downstream Project owner shall pay the Reservoir Party an amount equal to the product of the energy equivalent of such Assigned Water and the rate to be calculated under paragraph 14(a)(3), *Determination of Regular Interchange Energy Rate*. The energy equivalent shall be calculated by multiplying the remaining Assigned Water by the average energy conversion factor of the downstream Project during the Drawdown Period immediately preceding termination of this Agreement.

(8) Accounting

Each day each Reservoir Party shall provide an accounting to each downstream Project owner of such downstream Project owner's right to storage releases, In Lieu Energy schedules, and projections of reservoir outflows.

(9) Assumed Useable Generation

For the purposes of calculations under this subsection 9(j), the Reservoir Party and the downstream Party shall assume (i) that all reservoir and downstream generating units are operable, and (ii) that all water that could be used by such generating units is useable for generation. In making such calculations the Reservoir Party and the downstream Party shall include tailwater encroachment settlements.

(k) Adjustments in Firm Energy Load Carrying Capability During Operating Year

(1) Adjustments

A Party may, by giving notice to the Coordinating Group, advance or delay its FELCC in any month of the Operating Year subject to the limitations in this subsection 9(k). The Coordinating Group shall determine whether the requested adjustments comply with such limitations and shall maintain an FAA of each Party's FELCC in megawatt hours. The limitations are as follows.

(A) Individual Party Limitations

(i) Balancing of Firm Energy Load Carrying Capability Adjustments

A Party may advance or delay its FELCC so long as that Party's FAA balance is zero both (i) at the end of the Operating Year, and (ii) at the end of the Critical Period originally associated with the adopted FLCC if the Critical Period ends in such Operating Year.

(ii) Cap on Individual Party Adjustments

A Party may advance up to five percent of its FELCC remaining between the date of such advancing and the time such Party's FAA balance must be zero; *provided* a Party may never have outstanding more than five percent of its then-remaining FELCC.

(iii) Additional Individual Party Limitations

Except for increases of FELCC previously delayed under paragraph 9(k)(2) below, a Party may not advance its FELCC in any Period in the Operating Year by more than the sum of the following amounts.

(a) Load Overrun

For any part of August that falls outside the Critical Period, an amount equal to the difference between the Actual Firm Energy Load of a Party and that Party's Estimated Firm Energy Load ("EFEL") submitted for such part of August; for all other Periods, the difference between the Party's Actual Adjusted Energy Load and that Party's Estimated Adjusted Energy Load ("EAEL").

(b) Maintenance and Forced Outage

An amount equal to the energy-capability difference between (i) the actual Maintenance Outages and Forced Outages during such Period and (ii) the Maintenance Outages scheduled for such Period pursuant to subsection 8(a), *Maintenance*, and paragraph 6(f)(3), *Revisions to Maintenance*.

Any advancing of FELCC for other purposes must be unanimously approved by all of the Parties.

(B) Coordinated System Limitation

The sum of the Parties' FAA accounts with positive balances shall not exceed(i) nine percent of the Coordinated System's remaining Hydroelectric Firm Energy Load Carrying Capability ("Hydroelectric FELCC") between the date of such advancing and the time the sum of such Parties' FAA balances must be zero or, if Treaty Storage is not permitted to be affected by changes in FELCC, (ii) six percent of such Hydroelectric FELCC.

(C) Timing of Corresponding Adjustment

A Party requesting to advance FELCC shall indicate the Period in which it desires to return the FELCC. A Party may not schedule a return in a Period that it is not hydraulically useable or during the Period when such Party's FELCC was advanced; *provided* if the advancement of FELCC was served by the Coordinated System's surplus it can be returned in any Period.

(D) Allocation

When all Parties' requests to advance FELCC exceed the above limitations, the amount of FELCC that may be advanced shall be allocated among the Parties pursuant to subprocedure 9(b)-5.B., *Testing Submitted Flexibility Adjustments for Compliance with Flexibility Limitations*.

(2) Effect of Adjustments on Other Provisions/Demonstration of Ability to Support Adjustments with Critical Period Streamflows

Procedure 9(k)-2., *Delay of Firm Load Carrying Capability*, shall govern how a Party may delay its FELCC in any Period of the Operating Year; *provided* if such procedure is rescinded a Party may delay its FELCC by (i) maintaining an equivalent amount of storage in any of its reservoirs over their respective CRCs for such Period, (ii) deferring rights to storage releases under this Agreement, or (iii) making other arrangements for increasing its AEC equivalent to the increase in its FELCC, or by any combination thereof. Upon request by another Party or by the Coordinating Group, such Party shall demonstrate its ability to produce the claimed increase in the FELCC of the Coordinated System until the time such

Party's FAA balance must be zero under the streamflows in the Historical Period of Record used to establish FELCC.

(3) Accounting

A Party shall notify all other Parties of any advance or delay of FELCC pursuant to this subsection 9(k) within ten days after the end of the month to which such advance or delay applies and shall specify how that Party provided capability sufficient to make such advance or delay. A Party shall revise its AEC to reflect changes attributable to delay(s) of FELCC in its FAA. The Study Group shall modify the changing Party's FAA. Increases in FELCC shall be expressed as positive quantities.

(l) Provisional Energy

(1) General Provisions

Except as provided in subsection 9(g), *Operation of Reservoirs Below Energy Content Curves and Critical Rule Curves*, procedure 9(l)-2., *Reservoir Operating Margin*, and other relevant procedures, a Reservoir Party may draft any of its reservoirs in a manner that will cause such reservoirs to be below its end-of-Period ECC at the end of the current Period to produce Provisional Energy under the following conditions.

(A) Required Declaration of Provisional Draft

Any Reservoir Party which anticipates a Provisional Draft and which is able to make the demonstration required in subparagraph 9(l)(1)(B) below shall give notice to all affected Parties prior to making the Provisional Draft.

(B) Required Conditions

Any Party expecting to sell, dispose of, or use Provisional Energy (including energy returned to a Reservoir Party under subparagraph 9(l)(1)(C) below) must be able to demonstrate that such Party is able to recover the Provisional Energy it would sell, dispose of, or use and the incidental generating losses at the time the water otherwise would have been drafted based on the assumption that such storage water was the last increment of water drafted. Such demonstration shall be made by such Party upon request by any other Party. To make such demonstration, the Party shall establish that it (i) can recall the Provisional Energy that it proposes to use, or (ii) has committed other firm generating resources or stored energy not already committed for FELCC under this Agreement.

(C) Production of Provisional Energy/Options to Retain Energy or Produce Energy for Return

A Reservoir Party shall notify downstream Project owners of its schedule for Provisional Draft. Each downstream Project owner shall advise the Reservoir Party that it shall either retain or return the energy it can produce from the Provisional Draft to the Reservoir Party. If the downstream Project owner returns such energy, the Reservoir Party shall deliver to such owner, at the time that the water used to produce Provisional Energy would have been released, replacement energy in the amount that the downstream Project could have generated with such release. Neither Party shall charge the other for the energy exchanged under this subsection 9(l).

(D) Adjustment to Actual Elevations

For computations using "actual elevation" of a reservoir under this Agreement, such "actual elevation" shall be computed by (i) adding the water actually in storage at any time to the water in the Reservoir Provisional Draft Account at such time, and (ii) converting such sum to the equivalent elevation; *provided* "actual elevation" for any reservoir shall not exceed the normal top elevation for such reservoir.

(2) Accounting

(A) Reservoir Provisional Draft Account

Each Reservoir Party shall keep a separate reservoir Provisional Draft account, in thousands of second-foot days, of the Provisional Draft for each reservoir.

(B) Provisional Return Account

Each Reservoir Party and associated downstream Parties shall keep separate provisional return accounts of the water equivalent, in thousands of second-foot days, of the Provisional Energy returned by each downstream Party.

(C) Provisional Energy Retained Account

Each Reservoir Party and associated downstream Parties shall keep provisional energy retained accounts, in megawatt hours, that reflect the energy produced from the Provisional Draft and retained by such Party including, for the Reservoir Party, the Provisional Energy returned to the Reservoir Party by associated downstream Parties.

(m) Adjustments for Changes in Schedules of Firm Resource Availability

(1) Adjustments of Firm Load Carrying Capability for Changes to New or Additional Firm Resources

The Coordinating Group shall adjust the FLCC for each affected Party as follows for delays or advances in the availability of generating facilities scheduled pursuant to paragraph 6(a)(5), *New Firm Resources*, and used for the determination of its FLCC in section 6, *Determination of Firm Load Carrying Capability*.

(A) Delay in Availability

If there is such a delay, the Coordinating Group shall reduce the FLCC of each affected Party for the Period(s) of such delay by the amount of capacity and energy that the facility was scheduled to provide to each affected Party in the Load Determination Re-regulation ("LDR").

(B) Advance in Availability

If there is such an advance, any affected Party may require the Coordinating Group to rerun the LDR and increase its FLCC for the Period(s) of such advance by the amount of capacity and energy that the facility was scheduled to provide such affected Party in such LDR.

(C) Adjustments of Firm Load Carrying Capability for Changes to Initial Conditions of New Reservoirs

The Coordinating Group shall adjust the FLCC of each affected Party as follows for the actual elevation on July 31 in those reservoirs described in clause 6(c)(1)(A)(iii), *New Reservoirs*, as "new reservoirs" if such actual elevation is different from that in the LDR.

(i) Less Than Planned

If the July 31 actual elevation in a new reservoir is less than in the LDR, the Coordinating Group shall reduce the FELCC of each affected Party by the energy equivalent of the reduced storage. The Coordinating Group shall reduce the FELCC for each affected Party between the beginning of the Critical Period and March 31 of the current Operating Year in those Periods designated by each such Party.

(ii) Greater Than Planned

If the July 31 actual elevation in a new reservoir is greater than in the LDR, an affected Party may require the Coordinating Group to increase its FELCC by the energy equivalent of the increased storage, using the affected Party's energy conversion factor to calculate such increase in FELCC. The Coordinating Group shall increase the FELCC for each affected Party between the beginning of the Critical Period and March 31 of the current Operating Year in those Periods designated by each such Party.

(n) Transfers Due to Forced Outage

(1) Thermal Firm Resource Outages

A Party experiencing a Forced Outage of a thermal Firm Resource may require a Party having unused available thermal capability to deliver energy in an amount that is the lesser of (i) the megawatt amount of the available thermal energy, or (ii) the megawatt amount of the Forced Outage. The Supplying Party may not operate its reservoirs below the elevations permitted under subsection 9(g), *Operation of Reservoirs Below Energy Content Curves and Critical Rule Curves*, in the absence of such delivery in order to provide the energy. The Receiving Party shall pay for all energy received under this paragraph 9(n)(1) at the charge specified in paragraph 14(d)(2), *Energy*.

(2) Loss of Load

A Party facing a loss of load due to a Forced Outage may require the delivery of emergency capacity from any Party with excess Forced Outage Reserve as follows. The amount of the Receiving Party's request for transfer shall not exceed the lesser of (i) the amount needed to prevent the Receiving Party's loss of load, and (ii) the megawatt amount of the Receiving Party's Forced Outage minus the megawatt amount of its Forced Outage Reserve. The Supplying Party shall not be required to deliver an amount that exceeds its excess Forced Outage Reserve, which is its Forced Outage Reserve minus the sum of its then-existing Forced Outages and emergency capacity it delivers at the same time to other Parties. The Supplying Party may require the Receiving Party either to return the energy associated with the transfer of emergency capacity within one week or to purchase such energy pursuant to paragraph 14(d)(2), *Energy*.

(3) Capacity Calculation

The Receiving Party shall pay the Supplying Party the capacity charge provided in paragraph 14(d)(1), *Capacity*, for transfers of energy pursuant to paragraphs 9(n)(1) and 9(n)(2) above as follows. Transfers due to Forced Outages shall be accounted for on a calendar week basis. The capacity measurement for purposes of such charge shall be based upon the maximum amount requested and delivered during any hour; *provided* if the Supplying Party is unable during that calendar week to deliver subsequent transfer(s) at a rate equal to the initial transfer rate, the capacity measurement shall be reduced to the lesser amount.

(o) Operating Data and Deviations

Each Party shall prepare in advance and coordinate with other Parties in accordance with Exhibit I, *Scheduling Provisions*, hourly schedules of energy and capacity deliveries for each day. Each Party shall identify and separately account for simultaneous and offsetting transfers of energy for each hour. Such scheduled transfers shall be deemed to have been made at the point of delivery when delivered through the Supplying Party's interconnections. The Parties shall minimize and account for operating deviations from the schedule. The Parties promptly shall exchange operating data as necessary for determinations under this Agreement.

As far in advance as practicable each Party shall coordinate with other affected Parties full or partial operational interruptions to facilitate repairs, maintenance, or replacement of facilities. If such interruptions occur, the Party modifying energy or capacity schedules shall compensate the affected Parties by making corresponding adjustments to future energy and capacity delivery schedules under similar water supply and load conditions.

(p) Cross-Border Flows

The Parties shall treat deviations in the use of Other-Than-Treaty Storage pursuant to procedure 9(p)-1., *Cross-Border Flows*.

Section 10. Transmission Lines and Associated Facilities

(a) Coordinated System Transmission

Subject to this Agreement, the Parties may use capacity available in transmission lines and associated facilities owned, leased, or otherwise controlled as part of the Systems of other Parties without charge for the delivery of (i) Interchange Capacity, (ii) Interchange Energy, (iii) Holding Energy ("HE"), (iv) In Lieu Energy, (v) energy transferred to or from storage under subsection 9(i), *Storage of Energy in Reservoirs*, and (vi) for the delivery of Provisional Energy from a downstream Party to a Reservoir Party or the replacement of that energy by the Reservoir Party pursuant to subparagraph 9(l)(1)(C), *Production of Provisional Energy/Options to Retain Energy or Produce Energy for Return*; *provided* where such capacity is provided by a Party acting solely as a transferor and the use of such capacity has not otherwise been provided for, a transmission charge shall be applied as provided in subsection 14(g), *Transmission Service Charges*; *provided further* except for transfers of Interchange Capacity, such transferor shall not be obligated to make such capacity available during any hours it has designated to the affected Parties as Peak Load Hours, except on Sundays and national holidays.

(b) System Transmission

Each Party shall provide adequate firm transmission capacity through ownership, lease, or other firm arrangements to make useable its Firm Load Carrying Capability ("FLCC"). At the request of any Party, the Parties shall review compliance with the transmission requirements of this subsection 10(b) and prepare such studies as may be required to determine such matter. The Parties shall exchange all data necessary for such studies. If the Coordinating Group determines that a Party has not provided the required adequate transmission capacity, such Party's FLCC shall be appropriately reduced unless arrangements are made to overcome such deficiency.

(c) Transmission Scheduling

The Parties shall schedule power and energy to be delivered hereunder to a directly interconnected System in such amounts that the difference between the quantities scheduled in opposite directions shall not exceed the available capacity of the interconnecting transmission lines and associated facilities. When such power and energy is to be delivered through such interconnected System to other Systems, it shall be so designated at the time of the scheduling.

Section 11. Reactive

The Parties shall coordinate their operations so that the flow of reactive power does not adversely affect the Coordinated System or the directly interconnected Systems.

Section 12. Loads in Excess of Capabilities

Any Party having a load in excess of the sum of its Firm Load Carrying Capability and the secondary energy to which it has rights under section 9, *Operating Procedures, Obligations, and Rights*, shall supply that excess load from power and energy sources other than its Firm Resources, and shall not have a right to power or energy for such excess load from the Coordinated System.

Part IV. Rates and Charges

This part shall not come into effect until the August 1 following the Effective Date.

Section 13. Payment for Coordinated Storage Releases From Reservoirs Located in the United States

(a) Computation of Payments

The Parties owning or operating downstream Projects that have a right under this Agreement to coordinated storage releases from upstream reservoirs controlled by dams located in the United States shall make annual payments to the owners or operators of such reservoirs. The payments for all years shall be computed as follows.

(1) Annual Costs

The Reservoir Party shall determine the annual costs to be borne by power arising from ownership and operation of the dam and reservoir furnishing the benefits. Such annual costs shall include that part of the interest, maintenance, and depreciation (or similar charges) to be borne by power under applicable law, and that part of the operation expenses (including land rentals and similar charges), administrative and general costs, and taxes other than net income taxes to be borne by power. Each Reservoir Party annually shall submit to the Coordinating Group the capital and annual costs for each Project for which headwater payments are to be made. The Coordinating Group shall publish these updated costs in Exhibit J, *Computation of Payments Under Subsection 13(a), Payment for Coordinated Storage Releases from Reservoirs Located in the United States*, and shall apportion such annual costs between the storage and head functions.

(2) Storage Component of Annual Cost

The Coordinating Group shall determine the cost to be apportioned to the storage function according to Formula 13 below.

Formula 13

$$C_s = C_p(P_s + A_s)/(P_s + A_s + P_h + A_h)$$

Where,

C_s = Annual power cost of the dam and reservoir apportioned to storage.

C_p = Annual cost of the dam and reservoir to be borne by power both at site and downstream.

P_s = Critical Period energy, at site and downstream from at-site storage as determined pursuant to paragraph 13(a)(4) below.

A_s = Average annual useable energy, at site and downstream from at-site storage after adjustment to reflect the relative values of average annual and Critical Period energy, all as determined and adjusted pursuant to paragraph 13(a)(3) below.

P_h = Critical Period energy, at site from unregulated flow and from at-site and upstream storage as determined pursuant to paragraph 13(a)(4) below.

A_h = Average annual useable energy, at site from unregulated flow and from at-site and upstream storage after adjustments reflecting the relative values of average annual and Critical Period energy, all as determined and adjusted pursuant to paragraph 13(a)(3) below.

(3) The Average Annual Values

The Coordinating Group shall use the reservoir regulations made pursuant to subparagraph 7(d)(4)(A), *Trial Refill Regulation Based on Minimum Flow Variable Energy Content Curves*, adjusted for changes in Energy Content Curves ("ECC") made pursuant to subparagraph 7(d)(4)(b), *Refill Regulation*, to determine the average annual useable energy to be adjusted as hereinafter provided in this paragraph 13(a)(3).

The Coordinating Group shall determine average annual energy gains from storage before adjustments for tailwater encroachment and usability for each Project for each Period by computing the energy capability of such Project with and without storage. The Coordinating Group shall adjust the resulting increment of energy from storage for each Period by the obligation to deliver energy or right to receive energy from an adjacent Project that arises out of a settlement for tailwater encroachment. The amount of such obligation assigned to storage shall in each Period bear the same ratio to the total obligation in the

Period as storage use bears to total plant discharge in the Period. The Coordinating Group shall reduce the Coordinated System's total increment of energy gained or lost due to storage to the amount useable in the Coordinated System's estimated load after use of energy from unregulated flow. The Coordinating Group shall prorate such gain or loss to each Project in each Period in proportion to that Project's increment of energy due to storage.

The Coordinating Group shall assign the increments of average annual useable energy gain or loss at each Project from storage to each upstream reservoir in proportion to the storage change at each reservoir.

The A_s for each storage Project shall be the algebraic sum of these increments in megawatt months for that Project's storage at site and downstream, divided by the number of months in the study, and multiplied by 2.

The A_h for each storage Project shall be the algebraic sum of the useable energy at site from unregulated flow and the useable energy from at-site and upstream storage, divided by the number of months in the study, and multiplied by 2.

(4) Critical Period Values

The Coordinating Group shall use the Final Regulation to determine P_s and P_h for use in Formula 13.

The Coordinating Group shall determine Critical Period energy gains from storage before adjustment for tailwater encroachment for each Project for each Period by computing the energy capability with and without storage. The Coordinating Group shall adjust if applicable the resulting increment of energy from storage for each Period for the tailwater encroachment assigned to storage for that same Period as set forth in paragraph 13(a)(3) above and shall make further adjustments for any Restoration received from Projects that gain from Treaty Storage as determined in paragraph 6(k)(1), *Determination of Gains and Losses*. After such adjustments the Coordinating Group shall assign the increments from storage to all upstream reservoirs in proportion to each reservoir's storage release during the Critical Period. The P_s for each reservoir shall be the sum of these increments, in megawatt months, computed for such reservoir, including the increment computed at the reservoir Project itself, divided by the number of months in the Critical Period. The P_h for each reservoir Project shall be the sum of the energy, megawatt months, over the Critical Period from unregulated flow and from releases from at-site and upstream storage, divided by the number of months in the Critical Period.

(5) Annual Payment

The Coordinating Group shall distribute the costs apportioned to the storage function of each reservoir Project among the Projects, at site and downstream, in proportion to each Project's increment of the quantity ($P_s + A_s$) from the applicable reservoir. The owner or operator of each downstream Project shall pay the annual costs apportioned to such downstream Project to the owner or operator of such upstream reservoir Project, subject to the limit provided in subsection 13(b) below.

(b) Limit of Payment

The payments required in paragraph 13(a)(5) shall be limited so that they do not exceed the value of the benefits received from each storage Project. For payments determined between the Effective Date and the beginning of the first Operating Year, the Coordinating Group shall compute the value of benefits received from each storage Project and the appropriate limit pursuant to Subsection 13(b) of the Comprehensive Agreement. For the first Operating Year after the Effective Date, the Coordinating Group shall compute the value of benefits received from storage as the product of $5,000 multiplied by the total megawatts represented by each downstream Project's increment of the quantity ($P_s + A_s$) as described in paragraph 13(a)(5) above. Beginning the sixth Operating Year after the Effective Date, the Coordinating Group shall increase the dollar component of the formula $1,000 each year until it equals $10,000. After that time, the dollar component of the formula shall remain constant for the remainder of the term of the Agreement.

(c) Refusal Option

(1) Options for New Projects

Parties owning a Project(s) downstream from any dam and reservoir hereafter constructed in the United States shall have a right, not less than 60 days prior to the receipt at such Project(s) of the initial storage releases from any such dam and reservoir, to reasonably accurate estimates of the data required to make the computations described above, including the date when such releases shall be made. Such Parties shall, within 30 days of receipt of the data estimates, elect one of the following three options.

(A) Short-term Return

Make available for return to the reservoir owner or operator all energy that can be generated at such Project(s) from storage releases from such dam and reservoir for a period of ten years from the estimated date when such initial releases will be made, which period shall terminate at the end of an Operating Year, and accept such energy thereafter for the remainder of this Agreement’s term; *provided* prior to five years before the ten-year period terminates the downstream Parties may elect to make available for return such energy to the reservoir owner or operator for the remainder of this Agreement’s term.

(B) Return for Remainder of Contract Term

Make available for return such energy to the reservoir owner or operator for the remainder of this Agreement’s term.

(C) Acceptance of Energy

Accept such energy for the remainder of this Agreement's term.

Provided within 60 days after notice of any increase in the annual payment to be made to the owner or operator of such dam and reservoir, a downstream Party accepting energy from such dam and reservoir shall have an additional opportunity to elect subparagraph 13(c)(1)(A), 13(c)(1)(B), or 13(c)(1)(C) above.

(2) Return by Downstream Party Upon Release of Storage

The owner of a downstream Project(s) returning energy to the reservoir owner or operator pursuant to this subsection 13(c) shall make such energy available approximately concurrently with the receipt of the storage releases from the reservoir at the downstream Project(s), subject to the priorities on the use of machine capacity set forth in subsection 9(h), *Priorities on Use of Facilities for Power*. The reservoir owner or operator shall make available such energy at the high voltage side of the switchyard of the affected downstream Project(s), or an equivalent amount of water shall be spilled if so directed by the reservoir owner or operator.

(3) Return by Reservoir Party Upon Storage

When the reservoir owner or operator is storing water to refill its reservoir, the reservoir owner or operator shall make available to any downstream Party who returned the energy generated from storage releases under subparagraph 13(c)(1)(A) or 13(c)(1)(B) the energy that would otherwise have been useable at the downstream Project(s). The reservoir owner or operator shall return such energy approximately concurrently with the storing of such water for reservoir refill, subject to the priorities on the use of machine capacity set forth in subsection 9(h), *Priorities on Use of Facilities for Power*. The reservoir owner or operator shall make available such energy at the high voltage side of the switchyard of the affected downstream Project(s).

(4) Relief from Payment

When a downstream Project is making energy available for the return to a reservoir owner or operator pursuant to this subsection 13(c) the owner of such downstream Project(s) shall be relieved of the obligation to pay to the reservoir owner or operator on account of such downstream Project(s) any amounts in excess of those required to be paid by Section 10(f) of the Federal Power Act and such reservoir owner or operator shall pay to the owner of such downstream Project(s) an amount equal to the Section 10(f) payments so required to be made.

(5) Generation Service Charge

The Party or Parties that are receiving energy from another Party due to the release or withholding of storage under this subsection 13(c) shall make a payment of $1.00 per megawatt hour as compensation for the generation of the energy actually so returned.

(d) Procedure on Payments

Downstream Parties shall make payments for each Operating Year under this section 13 except payments under paragraph 13(c)(5) above in twelve equal monthly payments due and payable on or before the fifteenth day of each month beginning September 1 of the first Operating Year and continuing each month through August 15, 2025. A downstream Project owner shall pay to the Administrator payments owed to the United States under this section 13. The Administrator shall hold such payments in suspense for the credit of such owner pending annual determination by the Federal Energy Regulatory Commission ("FERC") of the amount due to the United States from such owner to satisfy the requirements of Section 10(f) of the Federal Power Act as applied to Projects owned by the United States within this Agreement. Within thirty days after such determination by FERC, or prior to delinquency, whichever is sooner, the Administrator shall transfer to FERC from such funds to the extent available the amounts FERC determined necessary to satisfy the requirements of Section 10(f) as between such owner and such Projects of the United States of America. At the request of any Party, payments shall be appropriately adjusted to reflect any delay or advance from the schedule assumed for a new Firm Resource coming into service.

(e) Provision Relating to the Lewis River Basin

Payments for coordinated storage releases from reservoirs located in the United States as computed pursuant to the provisions of this section 13 shall not be applicable to Projects located on the Lewis River, Washington, since PacifiCorp and Public Utility District No. 1 of Cowlitz County, Washington, have entered into a power contract dated June 4, 1957, as amended September 1, 1983, and certain other agreements that provide for the settlement for headwater benefits for existing and potential Projects on the Lewis River in a different manner.

(f) Effect of Payments

It is the intention of the Parties that the payments provided for in this section 13 shall, among other things, constitute full satisfaction as between the Parties of all obligations under Section 10(f) of the Federal Power Act for the period covered by this Agreement. The Parties hereto agree to submit this Agreement promptly to FERC. The non-Federal Parties shall file this Agreement with FERC pursuant to 18 C.F.R. § 11.14.

(g) Provision Relating to Payments by the United States of America

The United States shall not be required to make payments, offsets, or credits under this Section 13 for benefits received by Federal Projects from coordinated storage releases from a non-Federal upstream reservoir Project completed after July 1, 1965, where the license for such non-Federal reservoir Project requires such non-Federal reservoir Project owner to provide such benefits without payments, offsets, or credits by the United States, nor shall any Party be required to make such payments, offsets, or credits on behalf of the United States.

Section 14. Other Charges

The charges listed in this section 14 shall be applicable to exchanges, transfers, and services performed under this Agreement.

(a) Rates for Regular Interchange Energy, Interim Cash Advances, and Settlement of Regular Interchange Energy Imbalances

(1) Interim Cash Advances

If the Supplying Party calls for an interim cash advance to pay for the delivery of Regular Interchange Energy under subsection 9(d), *Interchange Energy*, the Receiving Party shall pay such advance at the rate established pursuant to paragraph 14(a)(3) below. The Supplying Party shall refund any interim cash advance upon return of Regular Interchange Energy.

(2) Regular Interchange Energy Imbalances

The rate for a Receiving Party settling imbalances of Regular Interchange Energy owed to a Supplying Party under subparagraph 9(d)(3)(D), *Settling Interchange Energy Imbalances*, is that established in paragraph 14(a)(3) below. Any interim cash advances not returned by the Supplying Party shall be applied to the settlement of the imbalance.

(3) Determination of Regular Interchange Energy Rate

By July 31 the Coordinating Group shall establish a single rate for the following Operating Year to be applied both to interim cash advances referred to in subsection 9(d), *Interchange Energy*, and to the settlement of Regular Interchange Energy imbalances pursuant to subparagraph 9(d)(3)(D), *Settling Interchange Energy Imbalances*. The rate shall be in effect for interim cash advances or imbalances relating to Regular Interchange Energy delivered during that Operating Year even if (i) the interim cash advance is made, (ii) the energy is returned, or (iii) the imbalances are settled in a subsequent Operating Year under subparagraph 9(d)(3)(D), *Settling Interchange Energy Imbalances*.

In the absence of an applicable long-term procedure, the Coordinating Group shall determine the rate according to the Formula 14 below.

Formula 14

$$R = XY + Z$$

Where,

R = Rate.

X = The heat rate, which is 10,000,000 BTU per megawatt hour.

Y = Fuel price, which is the average cost in dollars per BTU of mainline interruptible or spot market gas price for the twelve-month average for the immediately preceding July through June at Sumas, Washington, determined by reference to *Inside FERC* or some similar publication in the event *Inside FERC* is no longer published.

Z = An adder, which is initially four and three-quarters dollars per megawatt hour, and which shall be adjusted annually to reflect changes in the Portland, Oregon, CPI as reflected in the CPI for all urban consumers, published by the Bureau of Labor Statistics.

(b) Interchange Energy Service Charge

No service charge shall be imposed upon a Party returning Interchange Energy for (i) energy returned during Heavy Load Hours ("HLH"), (ii) energy returned during Light Load Hours ("LLH") to the extent it was supplied during LLHs, or (iii) energy returned during hours requested by the Supplying Party. A service charge of $2.50 per megawatt hour shall be imposed upon a Receiving Party that returns Interchange Energy during any other hours.

(c) Interchange Capacity Imbalances

The Receiving Party shall pay the Supplying Party for Interchange Capacity imbalances between them as provided for in paragraph 9(e)(2), *Capacity Calculation*, at the end of each Operating Year at the rate of $2,000 per megawatt week. The Supplying Party may require an interim cash advance at such rate to pay for delivery of Interchange Capacity. The Supplying Party shall refund any interim cash advance upon the return of Interchange Capacity.

(d) Charges for Transfers Due to Forced Outages

(1) Capacity

At the end of each Operating Year, the Parties shall pay for capacity imbalances that are the result of transfers caused by Forced Outages as provided for in subsection 9(n), *Transfers Due to Forced Outage*, at the rate of $2,000 per megawatt week. The Supplying Party may require an interim cash advance to pay for delivery of capacity related to transfers due to Forced Outages. The Supplying Party shall refund any interim cash advance upon return of capacity related to transfers due to Forced Outages.

(2) Energy

For energy delivered under paragraph 9(n)(1), *Thermal Firm Resource Outages*, a Receiving Party shall pay a Supplying Party the greater of (i) the rate provided for Regular Interchange Energy set out in paragraph 14(a)(3) above, or (ii) the incremental cost of such energy plus an adder of $4.00 per megawatt hour, which adder shall be adjusted annually to reflect changes in the Portland, Oregon, CPI published by the Bureau of Labor Statistics for all urban consumers.

To the extent that the Supplying Party does not exercise its option to call for the return of energy that had been delivered pursuant to paragraph 9(n)(2), *Loss of Load*, a Receiving Party shall pay the Supplying Party the greater of (i) the rate provided for Regular Interchange Energy set out in paragraph 14(a)(3) above, or (ii) the rate representing the incremental cost of such energy as determined by the Supplying Party.

The Supplying Party may require an interim cash advance at such rate to pay for delivery of energy delivered under paragraph 9(n)(1), *Thermal Firm Resource Outages*. The Supplying Party shall refund any interim cash advance upon return of such energy.

(e) Holding Energy Charges

(1) Holding Energy Service Charge

A Supplying Party under subsection 9(c), *Delivery and Return of Holding Energy*, shall pay to the Receiving Party a total service charge of $3.50 per megawatt hour in two installments. The Supplying Party shall pay the first installment of $2.00 per megawatt hour at the time of delivery of Holding Energy ("HE") under paragraph 9(c)(1), *Requests for Holding Energy*, and shall pay the second installment of $1.50 per megawatt hour when the Receiving Party returns the HE under paragraph 9(c)(3), *Return of Holding Energy*.

(2) Holding Energy Re-shaping Charges

To the extent that a Delivering Party's delivery or return of HE exceeds the daily average and is in a shape other than uniform on all hours pursuant to paragraph 9(c)(4), *Uniform Hourly Schedules and Special Shaping*, such Delivering Party shall pay the Party receiving the energy $2.50 per megawatt hour for each megawatt hour delivered or returned during LLHs when such delivery or return exceeds the average hourly amount of energy delivered or returned that day.

(3) Refund Resulting from Conversion of Holding Energy to Storage

To the extent that HE is converted to energy stored under the provisions of paragraph 9(c)(2), *Conversion to Storage*, the Receiving Party shall refund to the Supplying Party $0.75 per megawatt hour. The unrefunded $1.25 per megawatt hour shall be retained by the Receiving Party in lieu of the charges under paragraph 14(f)(1) below.

(f) Stored Energy Service Charges

The Supplying Party shall pay the Receiving Party for stored energy services under this subsection 14(f), unless a refund is required as specified below. For purposes of this subsection 14(f), Peak Load Hours ("PLH") shall mean those PLHs designated by the Receiving Party. For purposes of this subsection 14(f), "short-term storage" shall mean energy that has been in storage for less than two weeks and "long-term storage" shall mean energy that has been in storage for two weeks or longer. A "first-in, first-out" accounting method shall be used to determine whether storage is short- or long-term when a requesting Party has stored energy with a Reservoir Party on more than one occasion. In such instances, deliveries out of storage accounts shall be applied first to decrease the balances of the earliest energy deliveries.

(1) Delivery Charges

A delivery charge shall be paid at the rates set forth in (A), (B), and (C) of this paragraph 14(f)(1) when energy is delivered for storage under paragraph 9(i)(1), *Regular Storage*. If stored energy is spilled, the Receiving Party shall refund delivery charges to the Supplying Party pursuant to paragraph 14(f)(5) below.

(A) Light Load Hours

Two dollars per megawatt hour when delivered during LLHs not designated as PLHs.

(B) Heavy Load Hours

One dollar per megawatt hour when delivered during HLHs not designated as PLHs.

(C) Peak Load Hours

There is no service charge for delivery of energy for storage during PLHs.

(2) Return Charges

(A) Return Charges For Short-term Storage

Energy returned from short-term storage pursuant to paragraph 9(i)(1), *Regular Storage,* shall be paid for at the following rates.

(i) Light Load Hours

One dollar per megawatt hour when returned during LLHs not designated as PLHs.

(ii) Heavy Load Hours

Three and one-half dollars per megawatt hour when returned during HLHs not designated as PLHs.

(iii) Peak Load Hours

Five dollars per megawatt hour when returned during PLHs.

(B) Return Charges For Long-Term Storage

There is no charge for the return of energy from long-term storage during LLHs not designated as PLHs. Energy returned from long-term storage at other times pursuant to paragraph 9(i)(1), *Regular Storage,* shall be paid at the following rates.

(i) Heavy Load Hours

Two and one-half dollars per megawatt hour when returned during HLHs not designated as PLHs.

(ii) Peak Load Hours

Four dollars per megawatt hour when returned during PLHs.

(3) Charges in Potential Spill Conditions

The Supplying Party shall pay for the storage of energy delivered during a Potential Spill Period at the rates established in paragraph 14(f)(1) above. The Supplying Party shall pay for the return of such storage at the rates established in paragraph 14(f)(2) above; *provided* that if the Reservoir Party subsequently notifies the Supplying Party that spill is imminent, the provisions of paragraph 14(f)(4) below shall not apply to the return of such storage.

(4) Charges in the Case of Imminent Spill

The following rates shall apply when stored energy is returned during an imminent spill condition (even if the energy is returned during a PLH) so long as a Reservoir Party has notified Parties who have stored energy in such Reservoir Party's reservoir that spill is imminent. There is no charge for the return of stored energy when the return of such energy occurs during LLHs. There shall be a charge of $2.50 per megawatt hour for stored energy returned during HLHs.

(5) Refund of Storage Charges when Storage is Spilled

When energy stored pursuant to paragraph 9(i)(1), *Regular Storage*, is spilled, the Receiving Party shall refund any initial charges paid to the Supplying Party for the spilled stored energy under paragraph 14(f)(1) above, or retained by the Receiving Party under paragraph 14(e)(3) above. The Reservoir Party that originally accepted the energy for storage shall refund the initial charges even if the stored energy was transferred to a reservoir of another Party pursuant to paragraph 14(f)(6) below prior to the stored energy being spilled. The charges refunded shall be computed by multiplying the megawatt hours of stored energy spilled by the weighted average of the applicable rates of the total energy stored by a Party with the Reservoir Party at the time of the spill, including the stored energy that was spilled.

(6) Transfers to Avoid Spill

There is no transfer charge when a Receiving Party, on its own initiative or as arranged by the Supplying Party, transfers stored energy from its reservoir to the reservoir of another Party to avoid probable spill. In such instances, the original Receiving Party shall keep the initial charge (i) received on delivery pursuant to paragraph 14(f)(1) above, or (ii) retained by the Receiving Party under paragraph 14(e)(3) above. The Receiving Party that returns the energy to the Supplying Party shall be paid the additional charges on return required under paragraph 14(f)(2) above. If stored energy is spilled after it is transferred, the initial charge (i) received on delivery pursuant to paragraph 14(f)(1) above, or (ii) retained by the Receiving Party under paragraph 14(e)(3) above shall be refunded by the original Receiving Party.

(g) Transmission Service Charges

The following Parties shall pay a charge to a Party providing transmission service pursuant to subsection 10(a), *Coordinated System Transmission*, when such Party acts solely as a transferor. In the absence of a separate agreement between the Parties involved for such transmission, the following rates shall apply.

(1) Interchange Energy

The Receiving Party shall pay $1.60 per megawatt hour for Interchange Energy deliveries or returns.

(2) Stored Energy and Holding Energy

The Supplying Party shall pay $1.75 per megawatt hour on both the delivery and return of HE pursuant to subsection 9(c), *Delivery and Return of Holding Energy*, or of stored energy pursuant to subsection 9(i), *Storage of Energy in Reservoirs*; *provided* if the HE or the stored energy after conversion to stored energy is spilled, no charge shall be made, or if a charge has been made, a refund shall be given.

(3) In Lieu Energy

The Delivering Party shall not pay to a Party that is acting solely as a transferor a charge for any delivery or return of In Lieu Energy except when such transferor is providing transmission service because the Delivering Party is using the capabilities of its facilities for a higher priority than such delivery or return in accordance with the priorities of subsection 9(h), *Priorities on Use of Facilities for Power*, in which case the Delivering Party shall pay to such transferor $2.00 per megawatt hour.

(4) Provisional Energy

The Reservoir Party shall pay $2.00 per megawatt hour for deliveries or replacements of Provisional Energy pursuant to subparagraph 9(l)(1)(C), *Production of Provisional Energy/Options to Retain Energy or Produce Energy for Return*.

(5) Interchange Capacity and Transfers due to Forced Outages

The Receiving Party shall pay $2.00 per megawatt hour for energy deliveries associated with the delivery of Interchange Capacity pursuant to section 9(e), *Interchange Capacity*, and energy deliveries or returns associated with the delivery of emergency capacity due to Forced Outages pursuant to section 9(n), *Forced Outage*.

(h) Billing

Other than interim cash advances as provided in subsection 9(d), *Interchange Energy*, and headwater benefit payments provided for in subsection 13(d), *Procedure on Payments*, Parties shall be billed monthly and make payment within 20 days after billing.

(i) Changes in Charges

(1) Scope of This Subsection 14(i)

The rates and charges provided for in this section 14 other than those rates and charges provided for in paragraphs 14(a)(3) and 14(d)(2) above are subject to review by the Parties and to change as provided in this subsection 14(i). The rates and charges provided for in paragraphs 14(a)(3) and 14(d)(2) above are not subject to this subsection 14(i), but are recalculated annually by the Coordinating Group pursuant to the methodologies contained in such paragraphs.

(2) Annual Option to Review Transmission Charges

Any Party may give notice prior to each July 1 specifying desired changes to transmission charges in subsection 14(g) above. Upon receipt of such notification, all Parties shall review the transmission charges referred to therein. Any changes made to such charges shall be subject to the written agreement of all of the Parties and shall become effective the Operating Year immediately following the date of such agreement by the Parties and receipt of all regulatory authorizations necessary to effectuate such change with respect to each Party.

(3) Review of Other Charges

Beginning in the fourth Operating Year after the Effective Date, any Party may prior to July 1 request changes in any of the rates and charges under this section 14 except those contained in paragraphs 14(a)(3), 14(d)(2), and subsection 14(g) above. The Parties may request changes to rates and charges annually; *provided* if any rate or charge is changed, such changed rate or charge shall remain in effect for three years before any further change to such rate or charge may be made. Any change made to any such rate or charge shall be subject to the written agreement of all of the Parties and shall become effective the Operating Year immediately following the date of such agreement by the Parties and receipt of all regulatory authorizations necessary to effectuate such change with respect to each Party.

(4) Procedure Where Parties Cannot Agree to Charges

If the Parties fail to agree on any change to rates or charges (including transmission and other charges) provided for in this section 14, the non-Federal

Parties hereto who are subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") with respect to any such rate or charge shall submit the matter on or before the following January 1 to FERC for determination, pursuant to the standards set forth in Section 205 of the Federal Power Act, of the rate or charge to be made by the Parties; and the other Parties hereto agree, insofar as they may lawfully do so, that the charges to be made by them shall not be in excess of the applied rate or charge so determined by FERC; *provided that* any of such other Parties may, but shall not be obligated to, reduce any rate or charge in effect at the time of such submission. Each Party hereby gives its irrevocable consent to the intervention by all other Parties in any such proceeding before FERC. After rates and charges are agreed upon by all of the Parties or are finally determined by FERC pursuant to this subsection 14(i), each Party shall diligently pursue obtaining all necessary regulatory and administrative review, approvals and authorizations necessary to effectuate such rate or charge with respect to such Party. Any FERC-determined rate or charge shall become effective at the beginning of the Operating Year simultaneously following receipt of all regulatory and administrative approvals and authorizations necessary to effectuate such rate or charge with respect to each of the Parties.

Part V. General Provisions

Section 15. Non-power Uses

Nothing in this Agreement shall require a Party to operate a Project in a manner inconsistent with its requirements for non-power uses or functions, and no Party shall be considered in violation of this Agreement or suffer any penalty thereunder because of any Project operation undertaken in good faith for the purpose of preserving priority to such non-power uses or functions, or of protecting against harm to human life or property.

Section 16. Regulatory and Judicial Authorities

This Agreement shall neither be nor become effective unless and until this Agreement has been approved, accepted for filing, or permitted to become effective by the Federal Energy Regulatory Commission ("FERC") (including under Section 22 of the Federal Power Act if required by FERC) without any change or new condition that is unacceptable to any of the Parties; *provided* if FERC requires a change in, or imposes a new condition on, this Agreement, this Agreement shall become effective only if all the Parties agree in writing to such change or new condition. If the date that this Agreement is approved, accepted for filing, or permitted to become effective by the FERC is between February 1 and August 1, the Effective Date shall be the first February 1 following such approval, acceptance for filing, or permission to become effective.

If any provision of this Agreement is invalidated by a final order of any regulatory or judicial authority having jurisdiction, the Parties shall consider whether to modify this Agreement so as to remove any impediment to validity of this Agreement. In the absence of such modification agreed to in writing by all of the Parties, the Comprehensive Agreement shall be in full force and effect in accordance with its terms.

Section 17. Integration

This Agreement replaces, as to the Parties, the Comprehensive Agreement; *provided* if this Agreement is invalidated as contemplated in section 16, *Regulatory and Judicial Authorities*, the Comprehensive Agreement shall be in full force and effect in accordance with its terms.

Section 18. Entire Agreement

This Agreement constitutes the entire agreement of the Parties with respect to the subject matter of this Agreement and all prior written and oral agreements, negotiations, communications, and understandings of any of the Parties with respect to such subject matter are merged and incorporated into, and superseded by, this Agreement; *provided* notwithstanding the foregoing this section 18 shall not merge the Comprehensive Agreement into this Agreement and shall not preclude the enforceability of the Comprehensive Agreement in the event that this Agreement is invalidated as contemplated in section 16, *Regulatory and Judicial Authorities*.

Section 19. Miscellaneous Provisions

(a) Survival of Rights and Obligations

No obligation incurred under this Agreement to return power or pay money shall be discharged by the termination, cancellation, expiration, or completion of this Agreement.

(b) Calculation of Time

Unless otherwise stated, any reference to a day means a calendar day. All time references shall be to Pacific Time.

(c) Amendment

No amendment to this Agreement or revocation of a method or procedure shall be effective unless it is in writing and signed by all of the Parties.

(d) Headings

The headings in this Agreement are provided for organizational purposes only and shall not be construed to modify or interpret any provision of this Agreement.

(e) Precedence

In the event of a conflict between a method or procedure and any provision of this Agreement, the provisions of this Agreement shall govern.

(f) Reservation of Rights

Each Party expressly reserves all of the rights (sovereign or otherwise), powers, and defenses that it may have.

Section 20. Preservation of Water Rights

Nothing contained in this Agreement shall be construed to abrogate, modify, limit, or otherwise change in any respect any water rights held by any Party.

Section 21. Uncontrollable Forces

No Party shall be considered to be liable for failing to fulfill any obligation under this Agreement if such failure is caused by an uncontrollable force. For purposes of this Agreement, "uncontrollable force" means any cause beyond the control of the Party affected, including, but not limited to, failure of facilities, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, restraint by court order, or requirement of state regulatory agency having jurisdiction, which by exercise of diligence and foresight such Party could not reasonably have been expected to avoid and which by exercise of reasonable diligence such Party is unable to overcome. "Uncontrollable force" also means a requirement of Federal regulatory agency or legislative body having jurisdiction which is beyond the control of the Administrator, the Division Engineer, the Regional Director, the United States Entity, the City of Eugene, Oregon, the City of Seattle, Washington, the City of Tacoma, Washington, Public Utility District No. 2 of Grant County, Washington, Public Utility District No. 1 of Chelan County, Washington, Public Utility District No. 1 of Pend Oreille County, Washington, Public Utility District No. 1 of Douglas County, Washington, Public Utility District No. 1 of Cowlitz County, Washington, Puget Sound Energy, Inc., Portland General Electric Company, PacifiCorp, The Washington Water Power Company, The Montana Power Company, and Colockum Transmission Company, Inc., (whichever is affected) and which by the exercise of diligence and foresight such Party or entity could not reasonably have been expected to avoid and which by exercise of reasonable diligence such Party or entity (whichever is affected) is unable to overcome.

Nothing in this section 21 shall be construed as expanding any of the obligations of any Party. Each Party shall give prompt notice of any uncontrollable force adversely affecting its ability to perform under this Agreement. Any Party affected by an uncontrollable force shall make reasonable efforts to remedy its inability to perform with reasonable dispatch; *provided* no Party shall be required to prevent or settle a strike or any other labor dispute against its will.

Section 22. Provisions Relating to Treaty Storage

(a) United States-Canada Operating Plans

The United States Entity shall use its best efforts to develop and implement operating plans for Canadian Storage with the Canadian Entity in order to obtain optimum power generation downstream in the United States consistent with the provisions of this Agreement and the Treaty. To this end the United States Entity will consult with the other parties hereto as provided in this Agreement.

(b) United States as Reservoir Party for Treaty Storage

The United States shall be the Reservoir Party in this Agreement for Treaty Storage as if such storage were a part of the United States of America's System; *provided* the United States shall not be obligated as a Reservoir Party to the extent the operating plans (including any revision thereof) agreed upon by the United States Entity and the Canadian Entity do not permit implementation of such obligation.

(c) Treaty Operating Plans

Under the Treaty, the United States Entity and the Canadian Entity are to annually agree on operating plans for the sixth succeeding year of operation and such operating plans are to be designed to achieve optimum power generation in both the United States and Canada or in either country as provided in the Treaty.

Prior to any agreement on such operating plans between the United States Entity and the Canadian Entity, the Parties shall cooperate and submit data to the United States Entity in accordance with criteria established by the United States Entity for development of an annual operating plan. The Parties may require the Coordinating Group to make studies of the Coordinated System, assuming utilization of available Treaty Storage, to provide guidance to the United States Entity in regards to the optimum generation desired by Parties in the United States. The Coordinating Group shall make such studies consistent with the provisions of the Treaty and on a timely basis. The United States Entity, consistent with its obligations under the Treaty, shall use its best efforts to achieve such utilization in the operating plan finally determined and agreed to with the Canadian Entity.

Unless mutually agreed otherwise by all of the Parties and consistent with the provisions of the Treaty, studies for the Coordinated System shall be conducted in accordance with the provisions and procedures set forth in sections 6, *Determination of Firm Load Carrying Capability*, 7, *Determination of Base and Variable Energy Content Curves*, and 8, *Maintenance and Reserves*.

(d) Non-delegation

Nothing in this Agreement shall be construed to be a delegation by the United States Entity of its rights and powers under the Treaty to any Party hereto, nor shall this Agreement impose upon the United States any liability for damages with respect to Canada's operation of Treaty Storage beyond the liability of Canada under Article XVIII of the Treaty.

(e) Deviations of Treaty Storage from Operating Plans

If the operation of Treaty Storage deviates from the operating plans agreed to between the United States and Canada under the Treaty and In Lieu Energy is not available to offset the impacts of such deviation, procedure 22(e)-1., *Deviations in Use of Treaty Storage*, shall govern the rights and obligations of the Parties.

Section 23. Provision Relating to Federal Reclamation Project Requirements

Nothing contained in this Agreement shall be construed to abrogate, modify, limit, or otherwise change in any respect the right or the obligation of the United States to furnish power and energy to its present or future Federal Reclamation Project requirements.

Section 24. Re-negotiation

(a) Mandatory Modifications

It is the Parties' intent under this Agreement that all of the Parties obtain net positive benefits from the coordination of their facilities over the term of this Agreement. The Parties recognize that their positions and the characteristics of the Coordinated System may change on account of, for example, additions of thermal generation and changes in load shape or periods of peak load demands. If such change has occurred and if the provisions of this Agreement no longer provide to the Parties and the Coordinated System optimum hydroelectric generation, the Parties shall modify this Agreement so as to accommodate such changes and to achieve optimum generation.

(b) Discretionary Modifications/Withdrawal

(1) Notice of Re-negotiation

If a Party at any time determines that it is materially less able to provide from its Firm Resources economic electric utility service to its customers during the balance of the term of this Agreement than it would have been able to provide had this Agreement not been in effect, such Party may by written notice to each other Party request re-negotiation of this Agreement to eliminate such condition.

(2) Notice of Withdrawal

Upon receipt of such notice, each of the Parties shall commence good faith negotiations with all of the other Parties with the objective of modifying this Agreement to eliminate such condition. If such negotiations fail to result in modification to this Agreement that is satisfactory to all of the Parties, the Party requesting re-negotiation may give written notice to each of the other Parties of withdrawal from this Agreement all of such Party's Firm Resource(s) except any Project or share of output of a Project which is upstream from the tailrace of Bonneville Dam. The withdrawal shall take effect at the beginning of the fifth Operating Year following the Operating Year in which such notice was given; *provided* if any three Parties, including at least one non-Federal Party, within one year of such notice challenge before any jurisdictional or regulatory authority having jurisdiction the existence of such condition and diligently pursue such challenge, such withdrawal shall not be effective until such challenge has been finally resolved in favor of the Party seeking withdrawal, in which case the withdrawal shall be effective at the end of the Operating Year in which the challenge is finally resolved or the beginning of the fifth Operating Year after notice, whichever is later. Upon withdrawal, all of the Parties shall settle all outstanding obligations pursuant to this Agreement arising from the withdrawal of such Project(s). Notwithstanding the foregoing, a Party that owns, controls, leases or has a participating share in a Project located above the tailrace of Bonneville Dam shall continue to coordinate such Project or such share.

Section 25. Notices

Notices under this Agreement shall be effective on dispatch when (i) mailed first-class return receipt requested in the United States postage prepaid, (ii) sent via electronic mail or similar successor technology, (iii) sent via facsimile copy, or (iv) sent in any other manner agreed to by the Coordinating Group and in each case addressed to the section 5, *Implementation of Agreement*, Coordinating Group representative of a Party or, in the case of the United States Entity, to the representatives of both the Division Engineer and the Administrator. Any notice to be given by the United States may be given by the Coordinating Group representative of either the Administrator, the Division Engineer, or the Regional Director.

Section 26. Additional Parties

(a) Parties

(1) Joinder of a Party

Any entity may join as a Party to this Agreement so long as it satisfies each of the following three conditions.

(A) Hydroelectric Resource

The entity has hydroelectric resource(s) with an aggregate generating capacity of at least five megawatts that would qualify as a Firm Resource(s) under (i) or (ii) of the definition of Firm Resource.

(B) Interconnected

Such qualifying hydroelectric resource(s) is adequately interconnected with such entity's other resources and transmission facilities and with the other Parties' Systems to accomplish the objectives of this Agreement.

(C) Coordination

Such entity coordinates such hydroelectric resource(s) to the fullest extent possible pursuant to the terms of this Agreement.

Any such joinder shall be evidenced by the execution of an addendum entitled "Agreement Joining Additional Party" which shall be signed by such additional party. The joinder shall bind such additional Party to all of the covenants, terms, and conditions of this Agreement and become effective on the next February 1 for planning provisions and on the first August 1 after such February 1 for operating provisions. All such addenda shall be attached to and incorporated into this Agreement.

(2) Removal of a Party

Subject to subsections 26(b) and 26(c) below, any entity that has been a Party shall cease to be a Party to this Agreement if and when it no longer has a hydroelectric Firm Resource that qualifies as a Firm Resource under (i) or (ii) of the definition of a Firm Resource.

(b) Transfer of a Project to a Non-Party

This subsection 26(b) shall not apply to retirement or permanent abandonment of Firm Resources. As soon as practicable, a Party that expects to transfer a Project or has notice of a potential involuntary transfer of a Project shall provide written notice to all of the other Parties of such transfer. The Party shall inform the transferee of the then outstanding energy obligations under this Agreement related to the Project.

(1) Involuntary Transfer/Project Above Tailrace of Bonneville Dam

If a Project above the tailrace of Bonneville Dam is involuntarily transferred, the transferring Party shall, subject to Federal and state law and regulation, use reasonable efforts to cause or induce the new owner to become a Party. In no event shall the transferring Party have any continuing obligation under this Agreement with respect to such Project, with the exception that any outstanding obligation to pay money or to return power, other than obligations relating to In Lieu Energy and Provisional Energy shall survive such transfer.

(2) Voluntary Transfer/Project Above Tailrace of Bonneville Dam

If a Project above the tailrace of Bonneville Dam is voluntarily transferred, the transferring Party shall, subject to Federal and state law and regulation, use its best efforts to require or cause the new owner to become a Party. If the new owner does not become a Party, the Parties shall determine how to address the removal of the Project as a Firm Resource under this Agreement.

(3) Transfer of Other Projects

If a Project that is not above the tailrace of Bonneville Dam is transferred, the transferring Party shall use its best efforts to require or cause the new owner to become a Party. If the new owner does not become Party, the transferor shall have no continuing obligation under this Agreement with respect to such Project; *provided* any existing obligation under this Agreement to return power or pay money shall not be discharged until satisfied.

If a Project is transferred and the transferee does not become a Party, the Study Group shall remove such Project from Exhibit D, *Coordinated System's Firm Resources as of June 18, 1997*.

(c) Transfer of a Project to a Party

In the event a Party acquires hydroelectric generation facilities upstream from the tailrace of Bonneville Dam in addition to those already coordinated by that Party, such facilities shall be coordinated in accordance with the terms of this Agreement. For the purposes of this subsection 26(c), such additional hydroelectric facilities include, but are not limited to, newly installed hydroelectric turbines at an existing facility and new hydroelectric generation facilities, whether obtained from another Party or from an entity not a Party.

Section 27. Kerr Project

Nothing in this Agreement shall require the continued coordination of the Kerr Project (Project No. 5) if and when the Kerr Project Federal Energy Regulatory Commission license is transferred from The Montana Power Company to the Confederated Salish and Kootenai Tribes.

Section 28. Execution in Counterparts

This Agreement may be executed in any number of counterparts. All such counterparts shall constitute a single document with the same force and effect as if all Parties signing a counterpart had signed all the other counterparts.

IN WITNESS WHEREOF the Parties have executed this Agreement as of the eighteenth day of June, 1997.

UNITED STATES OF AMERICA

BY THE BONNEVILLE POWER ADMINISTRATOR OF THE DEPARTMENT OF ENERGY

By Randall W. Hardy
Administrator and Chief Executive Officer

BY THE DIVISION ENGINEER, NORTHWESTERN DIVISION, U.S. ARMY CORPS OF ENGINEERS

By Robert H. Griffin
Brigadier General, U.S. Army
Division Engineer

BY THE REGIONAL DIRECTOR, BUREAU OF RECLAMATION, PACIFIC NORTHWEST REGION, DEPARTMENT OF THE INTERIOR

By John W. Keys III
Regional Director

THE UNITED STATES ENTITY,
designated pursuant to Article XIV of the Treaty,

BY THE BONNEVILLE POWER ADMINISTRATOR OF THE U.S. DEPARTMENT OF ENERGY

By Randall W. Hardy
Administrator and Chief Executive Officer

BY THE DIVISION ENGINEER, NORTHWESTERN DIVISION, U. S. ARMY CORPS OF ENGINEERS

By Robert H. Griffin
Brigadier General, U.S. Army
Division Engineer

THE CITY OF EUGENE, OREGON,
a municipal corporation of the State of Oregon

By Randy Berggren
General Manager

THE CITY OF SEATTLE, WASHINGTON,
a municipal corporation of the State of Washington

By Gary Zarker
Superintendent

THE CITY OF TACOMA, WASHINGTON,
a municipal corporation of the State of Washington

By Mark Crisson
Director of Utilities

Approved as to form & legality
George S. Karavitis
Senior Asst. City Attorney

PUBLIC UTILITY DISTRICT NO. 2
OF GRANT COUNTY, WASHINGTON,
a municipal corporation of the State of Washington

By H. E. Williams
Acting Manager

PUBLIC UTILITY DISTRICT NO. 1
OF CHELAN COUNTY, WASHINGTON,
a municipal corporation of the State of Washington

By Roger A. Braden
General Manager

PUBLIC UTILITY DISTRICT NO. 1
OF PEND OREILLE COUNTY, WASHINGTON,
a municipal corporation of the State of Washington

By Larry Weis
General Manager

PUBLIC UTILITY DISTRICT NO. 1
OF DOUGLAS COUNTY, WASHINGTON,
a municipal corporation of the State of Washington

By William C. Dobbins
CEO / Manager

PUBLIC UTILITY DISTRICT NO. 1
OF COWLITZ COUNTY, WASHINGTON,
a municipal corporation of the State of Washington

By J. Leon Smith
General Manager

PUGET SOUND ENERGY, INC.,
a corporation

By William A. Gaines
Vice President Energy Supply

PORTLAND GENERAL ELECTRIC COMPANY,
a corporation

By Walter E. Pollock
Senior Vice President

PacifiCorp,
a corporation

By Brian D. Sickels
Vice President

The Washington Water Power Company,
a corporation

By Gary Ely
Senior Vice President and General Manager

The Montana Power Company,
a corporation

By Richard F. Cromer
Executive Vice President

Colockum Transmission Company, Inc.,
a corporation

By Jack A. Speer
Vice President

Exhibit A

The Coordinating Group representatives appointed pursuant to section 5, *Implementation of Agreement,* of the Pacific Northwest Coordination Agreement unanimously adopt the following Organizational Rules for the conduct and organization of their activities:

Rule 1. Scope of Authority. The Coordinating Group may use the assistance of any person, firm, or organization to discharge its functions under section 5, *Implementation of Agreement*.

Rule 2. Officers. The officers of the Coordinating Group shall be a Chair and a Vice-Chair. Only representatives of the Parties and their alternates selected pursuant to section 5, *Implementation of Agreement,* may become the Chair or the Vice-Chair of the Coordinating Group.

Rule 3. Selection of Officers. A majority of the Coordinating Group shall elect the Chair and Vice-Chair at the beginning of each Contract Year. The Coordinating Group shall fill any vacancy at the next Coordinating Group meeting.

Rule 4. Rotation of Officers. The Chair shall rotate each year from a Federal Party to a privately owned utility to a publicly owned utility and through the rotation again, and the Vice-Chair shall rotate in a similar manner so long as the Chair and the Vice-Chair are never of the same affiliation.

Rule 5. Duties of Officers. The Chair shall preside at all Coordinating Group meetings, appoint committees, and perform such other duties as required. The Chair shall notify Coordinating Group representatives of Coordinating Group meetings at least four business days in advance of the time, place, and agenda for each meeting, and shall specifically identify the items requiring Coordinating Group action.

The Vice-Chair shall serve as Chair in the absence of the Chair and shall perform any other duties delegated by the Chair.

Rule 6. Records and Correspondence. The Chair shall ensure that records are kept of all meetings, the correspondence of the Coordinating Group is conducted, and all notes, studies, reports, and correspondence are distributed to representatives.

Rule 7. Meetings. Representatives or their alternates may attend meetings in person, by telephone, or by other methods agreed upon by the Coordinating Group. Upon request of any representative, the Chair shall call a meeting. Any representative may (i) designate another representative to act as proxy for the meeting or on specific issues, (ii) cast its written vote in advance, (iii) designate in writing another person not a representative to serve as its Party's representative for the meeting, or (iv) participate by telephone, or, upon making satisfactory arrangements with the Chair, vote by telephone. The Coordinating Group shall not decide any item not identified as an action item in the agenda.

Rule 8. Quorum. The attendance in person, by personal or written proxy, or by approved means of at least five-ninths of all representatives shall constitute a quorum. Those representatives attending a meeting attended by a quorum may act on behalf of the Coordinating Group upon unanimous vote.

Rule 9. Voting Rights. Each representative shall have one vote.

Exhibit B

Long-Term Methods and Procedures

Table of Contents

Introduction

The Parties have agreed to these methods and procedures pursuant to section 5, *Implementation of Agreement*. This exhibit includes long-term methods and procedures whose specific terms (30 years, ten years, or five years) are indicated at the beginning of each method or procedure.

References in this exhibit to the Agreement include mention of sections, subsections, paragraphs, subparagraphs, clauses, and subclauses, set off by parentheses.

The methods and procedures follow the order of the Agreement. Cross-references to methods include mention of methods, submethods, parts, subparts, articles, and subarticles, set off by periods. Cross-references to procedures include mention of procedures, subprocedures, parts, subparts, articles, and subarticles, set off by periods.

The headings in this document are provided for organizational purposes only and shall not be construed to modify or interpret any provision of these methods and procedures.

Section 1 Term and Termination

There shall be no long-term methods or procedures relating to this section.

Section 2 Definitions

Procedure 2-1. Additional Definitions

The Parties shall use the following definitions with the methods and procedures as well as the definitions contained in the Agreement.

Actual Energy Regulation ("AER") means a continuous Coordinated System simulation based upon Conservative Streamflow Estimates and actual streamflows, if available, that is run twice a month. There are a number of subsets of Actual Energy Regulations (for example, Base Non-power Requirement Actual Energy Regulation and Trial Non-power Requirement Actual Energy Regulation). The Controlling Actual Energy Regulation provides a foundation to determine the rights and obligations of the Parties. In developing the Controlling Actual Energy Regulation, subsets of Actual Energy Regulations may need to be run.

Actual Energy Regulation Ending Elevation ("AER EE") means the end-of-Subperiod elevation for each reservoir determined by the Controlling Actual Energy Regulation. When the Actual Energy Regulation Ending Elevation is at or below the Adjusted Energy Content Curve, it is used to determine In Lieu Energy rights. Only Actual Energy Regulation Ending Elevations occurring at the end of a Period are used to determine Provisional Draft. Any reference in the Agreement to end-of-Period elevations shall use the Actual Energy Regulation Ending Elevation of the last Subperiod of a Period.

Actual Energy Regulation Generation Impact ("AER Generation Impact") means the megawatt deficiency from an Unplanned Non-power Requirement remaining after the Maximum Generation Impact resulting from such non-power requirement is reduced by Coordinated System surplus. After calculation, the Actual Energy Regulation Generation Impact is placed into the Actual Energy Regulation and is then reduced by subsequent generation in excess of Firm Energy Load Carrying Capability.

Adjusted Energy Content Curve ("Adjusted ECC") means the Base Energy Content Curve that has been adjusted pursuant to subsection 9(f), *Adjustment of Energy Content Curves*.

Adjusted Request means the In Lieu Energy equivalent of (i) a downstream Party's daily request for a release of storage made pursuant to subsection 9(j), *Release of Water from Storage and In Lieu Energy Deliveries*, or (ii) a downstream Party's daily request for In Lieu Energy pursuant to procedure 9(j)-3., *In Lieu Energy Transactions for Federal Reservoirs and Mid-Columbia Projects*, after the initial request was converted to its In Lieu Energy equivalent and adjusted pursuant to subprocedure 9(j)-2.B., *Energy in Lieu of Storage Release*, so that it does not exceed the difference between such Party's Firm Energy Load Carrying Capability and its Required Actual Capability.

Aggregate Proffered Return means the aggregate of In Lieu Energy offered for return to a Reservoir Party by downstream Parties on any given day.

Assured Operating Plan ("AOP") means the yearly study prepared six years in advance that defines the operation of Treaty Storage in accordance with the Treaty, Article XIV, Annex A and Annex B.

Base Flexibility Actual Energy Regulation ("Base Flex AER") means an Actual Energy Regulation that is based upon the current Controlling Actual Energy Regulation run without any Flexibility Adjustments and is used with the Trial Flexibility Actual Energy Regulation in procedure 9(b)-5., *Actual Energy Regulation for Purposes of a Flexibility Request*, to determine reservoir impacts from all Flexibility Adjustments in the current Operating Year.

Base Unplanned Non-power Requirement Actual Energy Regulation ("Base UNPR AER") means an Actual Energy Regulation based upon the current Controlling Actual Energy Regulation that is run without any Unplanned Non-power Requirements or corresponding Actual Energy Regulation Generation Impacts and is used with the Trial Unplanned Non-power Requirement Actual Energy Regulation in procedure 9(b)-4., *Actual Energy Regulation for Purposes of an Unplanned Non-power Requirement*, to determine reservoir impacts from all Unplanned Non-power Requirements in the current Operating Year.

Composite Factor means for a Party for purposes of procedures 9(j)-3., *In Lieu Energy Transactions for Federal Reservoirs and Mid-Columbia Projects*, and 9(p)-1., *Cross-Border Flows*, the conversion factors relating water to energy for each such Party including any share of a Mid-Columbia Project assigned to such Party and is defined in procedure 9(j)-3., *In Lieu Energy Transactions for Federal Reservoirs and Mid-Columbia Projects*; *provided* the Bonneville Power Administrator's ("Administrator") Composite Factor means the sum of the Administrator's water-to-energy conversion factors at site and downstream of Grand Coulee including any share of a Mid-Columbia Project assigned to the Administrator.

Controlling Actual Energy Regulation ("Controlling AER") means the Actual Energy Regulation that (i) is used to establish Interchange Energy rights and obligations and to determine the Actual Energy Regulation Ending Elevation, and (ii) incorporates Unplanned Non-power Requirements submitted pursuant to procedure 9(b)-4., *Actual Energy Regulation for Purposes of an Unplanned Non-power Requirement*, and requested Flexibility Adjustments permitted under procedure 9(b)-5., *Actual Energy Regulation for Purposes of a Flexibility Request*. The annual procedures, and procedures 9(b)-4., *Actual Energy Regulation for Purposes of an Unplanned Non-power Requirement*, and 9(b)-5., *Actual Energy Regulation for Purposes of a Flexibility Request*, identify which Actual Energy Regulation is the Controlling Actual Energy Regulation and when it becomes effective.

Desired Hydroelectric Generation ("DHG") means the hydroelectric generation, in average megawatts, that is required to meet the Coordinated System's Estimated Adjusted Energy Load in any portion of an Operating Year in the Critical Period.

Detailed Operating Plan ("DOP") means the yearly study prepared prior to the Operating Year that may be more advantageous to both the United States Entity and the Canadian Entity than those that would arise from operation under the Assured Operating Plan. The Detailed Operating Plan is prepared in accordance with the Treaty, Article XIV. All variations from the Assured Operating Plan must be agreed to by both the United States Entity and the Canadian Entity.

Discretionary Return means a voluntary return of In Lieu Energy after suspension of a downstream Party's right to request further release of water under paragraph 9(j)(3), *In Lieu Energy Return*, and not a mandatory return of In Lieu Energy under that same paragraph.

Downstream Conversion Factor means a Party's total planned ability to convert water to energy both at site and downstream of a specified Project.

Election means the choice available under procedure 9(p)-1., *Cross-Border Flows,* to (i) a downstream Party to retain or to return a portion of the Flow Deviation Generation, or (ii) an Initiating Party to require a downstream Party to retain or to return a portion of the Flow Deviation Generation Difference.

Election Period means a downstream Party's selection of a time period in consecutive whole Operating Years in which its Subsequent Downstream Party's Election will apply to all Flow Deviation Generation Differences relating to an Other-than-Treaty-Storage Agreement.

Excluded Firm Resources means the Condit, Cushman #1, Cushman #2, Mossyrock, Alder, Mayfield, and La Grande Projects, which Projects shall not be considered Firm Resources the first August 1 after the Agreement becomes effective unless such Projects are submitted subsequent to the execution of the Agreement pursuant to subsection 6(a), *Load and Firm Resource Data*.

Expedited Unplanned Non-power Requirement Assessment means an accelerated determination of the impacts of an Unplanned Non-power Requirement using Trial and Base Unplanned Non-power Requirement Actual Energy Regulations that are run immediately upon the request of a Requesting Party.

Federal Reservoirs means the reservoirs owned, operated, or controlled by the United States, including Treaty Storage.

Federal Composite Reservoir means those Federal Reservoirs upstream from Chief Joseph Project for which the United States is the Reservoir Party.

Finally Agreed Operating Plan means the operating plan actually employed in the operation of Treaty Storage, as agreed between the United States and Canadian Entities pursuant to Annexes

A and B of the Treaty or as superseded, pursuant to Article XIV(k) of the Treaty, for any Operating Year prior to the beginning of the sustained drawdown of Treaty Storage during such Operating Year.

Firm Backup Energy means the ability to recall Provisional Energy or the commitment of the "other firm generating resources or stored energy" referred to in the last sentence of subparagraph 9(l)(1)(B), *Required Conditions.*

Firm Energy Load Carrying Capability Transaction ("FELCC Transaction") means for purposes of procedure 9(h)-1., *Priorities on Use of Facilities for Power*, a transaction needed to develop the Requesting Party's or Parties' Firm Energy Load Carrying Capability.

Flexibility Adjustment means an advancement or delay of Firm Energy Load Carrying Capability pursuant to subsection 9(k), *Adjustments in Firm Energy Load Carrying Capability During Operating Year*.

Flexing System means a Party that has (i) requested an advancement or delay of Firm Energy Load Carrying Capability pursuant to subsection 9(k), *Adjustments in Firm Energy Load Carrying Capability During Operating Year*, or (ii) dedicated Firm Energy Load Carrying Capability to refill pursuant to procedure 9(b)-6., *Foregoing Firm Energy Load Carrying Capability to Influence Refill in the Actual Energy Regulation*.

Flow Deviation means a daily volume deviation, in thousands of second-foot days, in the Canada-United States-border flows caused by an Other-than-Treaty-Storage Agreement, measured using BC Hydro's reported operating statistics, and calculated by subtracting the combined Treaty outflow of the Mica, Arrow, and Duncan Projects from the combined actual outflow of the Mica, Arrow, and Duncan Projects.

Flow Deviation Generation Difference means for a Party the difference in downstream Project generation caused by the Flow Deviation relating to an Other-than-Treaty-Storage Agreement computed by using such Party's Composite Factor or the Administrator's Composite Factor, whichever is appropriate. Negative Flow Deviation Generation Difference connotes a decrease in the Canada-United States-border flow.

Initial Actual Energy Capability ("Initial AEC") means the energy capability of each Party's Firm Resources as reflected in the Actual Energy Regulation.

Initial Election means a downstream Party's first Election relating to a designated amount of Other-than-Treaty Storage affected by an Other-than-Treaty-Storage Agreement.

Initial Offsets means preliminary adjustments, in average megawatts, identified for the Coordinated System's energy capability for each Offset Interval in the Preliminary Regulation and the Modified Regulation. Initial Offsets are adjusted to obtain a uniform Offset for the entire Critical Period by adjusting the Coordinated System's or, as appropriate, individual Party's(ies') EAEL(s) for each Offset Interval.

Initiating Party means a party to an Other-than-Treaty-Storage Agreement who causes a Flow Deviation under such agreement; *provided* the Administrator is the Initiating Party if the Flow Deviation (i) is caused by actions of nonsignatories of this Agreement in Canada, (ii) is consistent with the Treaty, and (iii) is consented to by the United States Entity.

Lower Limits to the Variable Energy Content Curve ("LLVECC") means the end-of-Period reservoir elevations designed to ensure that Coordinated System reservoirs will not be drafted empty prior to the start of the annual runoff which could result in the inability of the Coordinated System to meet its Firm Load Carrying Capability during the period January 1 through April 15. Such reservoir elevations shall limit the Variable Energy Content Curve to be no lower than the Lower Limits to the Variable Energy Content Curve. The need for Lower Limits to the Variable Energy Content Curve shall be determined annually and in a manner as agreed by the Coordinating Group using water conditions in January 1 through April 30 with the least capability to produce Firm Energy Load Carrying Capability.

Maximum Generation Impact means the amount of additional generation required as a result of an Unplanned Non-power Requirement (i) to develop the same level of Actual Energy Capability in the Trial Unplanned Non-power Requirement Actual Energy Regulation Re-regulation as in the Base Unplanned Non-power Requirement Actual Energy Regulation, and (ii) to satisfy the Recovery Criteria.

Mica Target Content means the end-of-Period content required at the Mica Project as set forth in the Detailed Operating Plan.

Mica Target Flow means the average discharge for a Period required at the Mica Project as set forth in the Detailed Operating Plan.

Mid-Columbia Project means any one of the following Columbia River hydroelectric developments: Wells, Rock Island, Rocky Reach, Wanapum, and Priest Rapids Projects. These Projects are referred to collectively as the Mid-Columbia Projects.

Minimum Actual Capability ("MAC") means a Party's Initial Actual Energy Capability adjusted to (i) add all rights to Interchange Energy or subtract a Party's actual deliveries of Interchange Energy, and (ii) conform the hydroelectric component of the Initial Actual Energy Capability to reflect upstream hydroelectric storage operations that deviate from the Controlling Actual Energy Regulation operations.

Net Non-hydroelectric Firm Resources means miscellaneous Firm Resources and thermal Firm Resources after adjustment for maintenance; *provided* miscellaneous Firm Resources that are hydroelectric Firm Resources located within the geographic location described in the definition of System shall not be considered Net Non-hydroelectric Firm Resources.

Non-Firm Energy Load Carrying Capability Transactions ("Non-FELCC Transactions") means for purposes of subsection 9(h), *Priorities on Use of Facilities for Power*, any transactions in the current Period not needed to develop Firm Energy Load Carrying Capability.

Offset Interval means the sequential Periods where (i) energy can be shaped between such Periods, and (ii) energy surpluses or deficits can be made uniform over such Periods.

Other-than-Treaty-Storage Agreement ("OTSA") means an agreement relating to Other-than-Treaty Storage that may affect the expected Treaty Flow at the Canada-United States-border, which agreement is entered into by an Initiating Party and affects the flow of the Columbia River at the Canada-United States-border in a way that is not addressed by the Provisional Energy or In Lieu Energy provisions of the Agreement.

Owner means the respective owners of the Mid-Columbia Projects: Public Utility District No. 1 of Chelan County, Washington (Rock Island and Rocky Reach Projects); Public Utility District No. 1 of Douglas County, Washington (Wells Project); and Public Utility District No. 2 of Grant County, Washington (Wanapum and Priest Rapids Projects).

Participant means a Party, other than the Owner, that receives a share of the output from one or more Mid-Columbia Projects.

Period has the meaning set forth in the Agreement; *provided* the first 15 days of April and August are each considered a Period and the balance of each April and August is considered a Period. Each Period shall contain one or two Subperiods.

Pooled H/K In Lieu Limit ("PHILL") means the total quantity of In Lieu Energy available from a single or any composite reservoir.

Power Discharge Requirement ("PDR") means for a Period the hypothetical minimum flow at a Project used in the calculation of Assured Refill Curves and Variable Energy Content Curves. The Power Discharge Requirements are determined for an Operating Year in the Refill Regulation. In the Refill Regulation, Power Discharge Requirements are changed to adjust the Assured Refill Curves and Variable Energy Content Curves for purposes of passing the "refill test".

Prescheduled Day(s) means the next succeeding working day and intervening non-working day(s) for which energy schedules are being prepared.

Provisional Energy Transaction ("PET") means energy delivered from or to a downstream Party pursuant to subparagraph 9(l)(1)(C), *Production of Provisional Energy/Options to Retain Energy or Produce Energy for Return*, as a result of Provisional Draft.

Recovery Criteria means the following three conditions used pursuant to procedure 9(b)-4., *Actual Energy Regulation for Purposes of an Unplanned Non-power Requirement*, to determine whether generation impacts related to Unplanned Non-power Requirements are placed in the Actual Energy Regulation, and pursuant to procedure 9(b)-5., *Actual Energy Regulation for Purposes of a Flexibility Request*, to determine whether proposed Flexibility Adjustments will be allowed in the Actual Energy Regulation.

(i) ***Development of Actual Energy Capability***

The Coordinated System meets its Actual Energy Capability as developed in the Base Unplanned Non-power Requirement Actual Energy Regulation or in the Base Flexibility Actual Energy Regulation, respectively.

(ii) ***Acceptable End-of-July Actual Energy Regulation Ending Elevations***

There are no reductions in the end-of-July Actual Energy Regulation Ending Elevations in the Trial Unplanned Non-power Requirement Actual Energy Regulation when compared with the Base Unplanned Non-power Requirement Actual Energy Regulation or in the Trial Flexibility Actual Energy Regulation when compared with the Base Flexibility Actual Energy Regulation, respectively, unless each of the affected Reservoir Parties agrees to accept the reductions at its reservoir(s); and

(iii) ***Accommodation of Non-power Requirements***

Non-power requirements are met with the same level of compliance as in the Base Actual Energy Regulation or in the Base Flexibility Actual Energy Regulation, respectively.

Relative Maximum Discharge means the product of (i) each Mid-Columbia Project's maximum turbine discharge less that median incremental natural streamflow between such Mid-Columbia Project and the Chief Joseph Project as calculated in C.5. of procedure 9(j)-3., *Median Incremental Streamflows,* and (ii) the downstream Party's percent allocation in such Mid-Columbia Project times the product of such Mid-Columbia Project's energy conversion factor and 24 hours per day.

Requesting Party means the Reservoir Party requesting an assessment of the impacts that an Unplanned Non-power Requirement at such Party's reservoir will have on the Coordinated System's Actual Energy Capability. For the purposes of this definition the Corps of Engineers or the Bureau of Reclamation each may be a Requesting Party for its respective Projects, and the Administrator may be a Requesting Party for all Federal Reservoirs.

Required Actual Capability ("RAC") means a Party's Actual Energy Capability adjusted by assuming (i) such Party is fully exercising its right to Interchange Energy, (ii) such Party's actual deliveries of Interchange Energy satisfy its total obligation to deliver Interchange Energy, (iii) all non-hydroelectric Firm Resources run as submitted in section 6, *Determination of Firm Load Carrying Capability*, planning, and (iv) all Projects generate at the level indicated in the Controlling Actual Energy Regulation as adjusted for operational deviations by upstream Projects.

Reservoir Operating Margin means the reservoir elevation below the Actual Energy Regulation Ending Elevation to which a reservoir may operate under procedure 9(l)-2., *Reservoir Operating Margin*, without its Reservoir Party declaring Provisional Draft. The Reservoir Operating Margin is determined by subtracting from the storage equivalent of the daily interpolation of Energy Content Curves used for determination of In Lieu Energy rights the greater of (i) the storage equivalent of five feet of elevation, or (ii) the storage equivalent of the Project's twelve-hour discharge at its maximum turbine capability. If a reservoir is drafted below its Reservoir Operating Margin the Reservoir Party must declare Provisional Draft.

Reservoir Operating Margin Draft means the amount, in thousands of second-foot days, that a reservoir has descended into the Reservoir Operating Margin causing In Lieu Energy rights to become negative within a Period.

Reservoir Operating Margin Exchanges means deliveries of energy between a Reservoir Party and one or more participating downstream Parties under procedure 9(l)-2., *Reservoir Operating Margin*, resulting from reservoir operations within the Reservoir Operating Margin.

Reservoir Provisional Draft Account means the account maintained by the Reservoir Party pursuant to subparagraph 9(l)(2)(A), *Reservoir Provisional Draft Account*, indicating the amount of Provisional Draft, in thousands of second-foot days, for a reservoir.

Returning Party means for purposes of procedure 9(p)-1., *Cross-Border Flows*, a downstream Party who during an Election Period either (i) elects to return the portion of Flow Deviation Generation Difference under its control, or (ii) must return the portion of the Flow Deviation Generation Difference under the Initiating Party's control.

Shifting Interval means the time period commencing at the beginning of the Critical Period and ending at one of the points in the Critical Period where the Coordinated System's generation is insufficient to cover its Estimated Adjusted Energy Loads. If the insufficiency exists for more than one Period, the Shifting Interval shall continue through all contiguous Periods of insufficiency. There may be more than one Shifting Interval within a Critical Period. A Shifting Interval is used as part of the section 6, *Determination of Firm Load Carrying Capability*, planning methods to ascertain which Shifting System's(s') shifting intentions caused the failure of the Coordinated System to cover its Estimated Adjusted Energy Loads.

Spokane River Composite Reservoir means the Coeur d'Alene and Long Lake Projects, which are reservoirs on the Spokane River owned by The Washington Water Power Company.

Study Group means the Coordinating Group or its nominee acting solely under its direction.

Submitting Party means the Project owner, or, in the case of Treaty Storage, the United States Entity, that submits an Unplanned Non-power Requirement for consideration pursuant to procedure 9(b)-4., *Actual Energy Regulation for Purposes of an Unplanned Non-power Requirement*.

Subperiod means each of (i) the first 15 days of any month, and (ii) the balance of such month.

Subsequent Downstream Party's Election means a downstream Party's choice in procedure 9(p)-1., *Cross-Border Flows*, to change either its Initial Election or any of its later Elections.

Subsequent Initiating Party's Election means any Election made by an Initiating Party under procedure 9(p)-1., *Cross-Border Flows*, after a downstream Party's Initial Election.

Transfer Energy means that portion of the Flow Deviation Generation Difference that is transferred between an Initiating Party and a Returning Party pursuant to procedure 9(p)-1., *Cross-Border Flows*.

Treaty Flow means the flows from Treaty Projects as requested by the United States Entity and agreed to by the Canadian Entity.

Treaty Storage Regulation ("TSR") means the hydroelectric regulations that simulate the operating criteria specified in the Detailed Operating Plan. Treaty Storage simulation resulting from such regulation is used in the Actual Energy Regulation and the Refill Regulation.

Trial Flexibility Actual Energy Regulation ("Trial Flex AER") means an Actual Energy Regulation based upon the current Controlling Actual Energy Regulation used with the Base Flexibility Actual Energy Regulation to determine the impact of the currently submitted Flexibility Adjustment(s) pursuant to procedure 9(b)-5., *Actual Energy Regulation for Purposes of a Flexibility Request*. The Trial Flexibility Actual Energy Regulation is run with (i) all previous Flexibility Adjustments, and (ii) the Flexibility Adjustment currently requested by the Flexing System.

Trial Unplanned Non-power Requirement Actual Energy Regulation ("Trial UNPR AER") means an Actual Energy Regulation based upon the current Controlling Actual Energy Regulation used with the Base Unplanned Non-power Requirement Actual Energy Regulation to determine the impact of the currently submitted Unplanned Non-power Requirement(s) pursuant to procedure 9(b)-4., *Actual Energy Regulation for Purposes of an Unplanned Non-power Requirement.* The Trial Unplanned Non-power Requirement Actual Energy Regulation is run with (i) all Unplanned Non-power Requirements submitted in that Operating Year or submitted for implementation in that Operating Year, (ii) the currently submitted non-power requirements, and (iii) any remaining Actual Energy Regulation Generation Impact.

Trial Unplanned Non-power Requirement Actual Energy Regulation Re-regulation ("Trial UNPR AER Re-regulation") means a re-regulation of the Trial Unplanned Non-power Requirement Actual Energy Regulation to determine the Maximum Generation Impact, if any, to be added to the Controlling Actual Energy Regulation pursuant to procedure 9(b)-4., *Actual Energy Regulation for Purposes of an Unplanned Non-power Requirement*.

Unplanned Non-power Requirement means a reoccurring-non-power requirement (i) that the Submitting Party was unaware of prior to submission of subsection 6(a), *Load and Firm Resource Data*, preliminary data for the current Operating Year, or (ii) that, although communicated to the Parties during the section 6, *Determination of Firm Load Carrying Capability*, planning process, could not be modeled in the Final Regulation because the Submitting Party had insufficient knowledge of its characteristics or modeling and implementation requirements.

Withdrawing Party means a Party that has elected not to coordinate all of the same Projects under this Agreement as it did under the Comprehensive Agreement.

Section 3 Exhibits

There shall be no long-term methods or procedures relating to this section.

Section 4 Coordination/Priorities

There are currently no long-term methods or procedures relating to this section.

Section 5 Implementation of Agreement

Subsection 5(a) Coordinating Group

Procedure 5(a)-1. Technical Review Process

This long-term procedure 5(a)-1. has a ten-year term commencing on the Effective Date.

Any Party may require the Coordinating Group to undertake a technical review of any part(s) of this Agreement and methods and procedures, except sections 1, *Term and Termination*, 13, *Payment for Coordinated Storage Releases from Reservoirs Located in the United States*, 14, *Other Charges*, 15, *Non-power Uses*, 16, *Regulatory and Judicial Authorities*, 17, *Integration,* 18, *Entire Agreement,* 19, *Miscellaneous Provisions,* 20, *Preservation of Water Rights,* 21, *Uncontrollable Forces,* 22, *Provisions Relating to Treaty Storage*, 23, *Provision Related to Federal Reclamation Project Requirements,* and 24, *Re-negotiation*, and methods and procedures related thereto; *provided* if a question not relating to the charges for a particular service or the methodology for setting the same arises under section 14, *Other Charges*, any Party may require that the question be submitted to the technical review process. The Coordinating Group shall endeavor to adopt an analysis of such part(s) and shall take and keep notes of its discussions. Any Party may submit a short statement describing the relevant questions.

If the Coordinating Group fails to adopt an analysis regarding the part of the Agreement or method or procedure under review within 30 calendar days of the Party's request for a technical review, a majority of the Parties within 20 calendar days thereafter shall select a panel to analyze such part of the Agreement or method or procedure. The costs of the non-signatory panel members shall be allocated to the Parties consistent with the expense allocation in paragraph 5(a)(2), *Responsibility for Costs*; *provided* that any Party may elect not to pay for the costs by providing written notice of its election within the 20 calendar days in which the panel is being selected, whereupon that Party's allocation shall be reallocated to the remaining Parties in a manner consistent with paragraph 5(a)(2), *Responsibility for Costs*. The panel shall not exceed three persons, and may include Coordinating Group representatives. In selecting the panel the Parties shall consider each candidate's knowledge of the Agreement, impartiality, experience, and any other factors that the Parties consider pertinent.

The panel's technical review shall be restricted to the following documents in effect at the time of the request: the Agreement, any amendments, addenda, settlement agreements, exhibits, methods and procedures, attachments, evaluations under this process, statements of questions, and Coordinating Group or subcommittee notes, including any notes addressing the questions under review. Within 30 calendar days of its formation the panel shall provide its written conclusion, with supporting logic, to the Coordinating Group.

Within 30 calendar days the Coordinating Group shall review the panel's conclusion and shall in the order provided below:

(i) Adopt the Panel's Conclusion

Absent written objection by any representative, adopt the panel's conclusion; or if the panel's conclusion is not adopted; then

(ii) Adopt a Different Conclusion

With unanimous consent of the Parties, adopt a conclusion different from the panel's; or if a different conclusion is not adopted; then

(iii) Terminate the Process

Terminate the technical review process;

provided that nothing in this procedure gives the Coordinating Group the authority to amend the Agreement or a long-term method or procedure.

Procedure 5(a)-2. Modeling Attachment

This procedure shall have the same term as the Agreement.

The Coordinating Group shall develop modeling guidelines appropriate to deal with specific operating requirements submitted pursuant to subsection 6(a), *Load and Firm Resource Data,* and shall adopt these guidelines as an annual method or procedure. These guidelines shall be input to Attachment A of the annual procedures, and shall be updated by the Coordinating Group as required.

Section 6 Determination of Firm Energy Load Carrying Capability

Subsection 6(a) Load and Firm Resource Data

Method 6(a)-1. Data Submittal/Miscellaneous Firm Resources

This long-term method 6(a)-1. has the same term as the Agreement. The Parties shall reflect scheduled Maintenance Outages in any determination of the capability of miscellaneous Firm Resources under paragraph 6(a)(2), *Plant Data*.

Subsection 6(b) Necessary Procedures Prior to Running the Preliminary Regulation

Method 6(b)-1. Responsibilities of the Study Group After Determination of the Critical Period and Prior to Running the Preliminary Regulation

This long-term method 6(b)-1. has the same term as the Agreement.

For purposes of this method 6(b)-1., references to Operating Year(s) mean an Operating Year or part thereof within the Critical Period.

Summary: The Study Group shall calculate Desired Hydroelectric Generations ("DHG") for each Operating Year from data supplied under subsection 6(a), *Load and Firm Resource Data*, as provided below in submethod 6(b)-1.A. The Study Group shall then test the Coordinated System's Estimated Adjusted Energy Loads ("EAEL") to ensure compliance with applicable limitations on shifting by testing the DHGs for each Operating Year as provided below in submethod 6(b)-1.B. If the Coordinated System's EAELs meet the shifting limitations, those EAELs shall be used in the Preliminary Regulation. If the EAELs do not meet the shifting limitations, they shall be adjusted as provided below in submethod 6(b)-1.C.

A. Calculation of Desired Hydroelectric Generation

After determining the Critical Period but before running the Preliminary Regulation, the Study Group shall calculate DHGs for each Operating Year from data supplied under subsection 6(a), *Load and Firm Resource Data*, by subtracting the Coordinated System's Net Non-hydroelectric Firm Resources from the Coordinated System's EAELs.

B. The Coordinated System's Estimated Adjusted Energy Loads That Need Not Be Adjusted Prior to Use in the Preliminary Regulation

1. Non-increasing Desired Hydroelectric Generations

So long as the calculated DHGs do not increase from one Operating Year to the next Operating Year throughout the Critical Period, the Study Group shall use the Coordinated System's EAELs in the Preliminary Regulation.

2. Permissible Increasing Desired Hydroelectric Generations

If any increase in DHGs from one Operating Year to the next is less than or equal to the increase in the Coordinated System's Estimated Firm Energy Load ("EFEL") between the same Operating Years, the Study Group shall use the Coordinated System's EAELs in the Preliminary Regulation.

C. Adjustments to the Coordinated System's Estimated Adjusted Energy Loads for Use in the Preliminary Regulation

If the increase in DHGs from one Operating Year to the next is more than the increase in the Coordinated System's average EFEL for the same Operating Years, the Study Group shall reduce the EAELs for the Coordinated System for such Operating Year by the lesser of (i) the amount that the increase in the Coordinated System's EAEL exceeds the change in the Coordinated System's average EFEL (even if the change is negative), or (ii) the amount that the DHG increases in the Operating Years. The Study Group shall distribute equally any reduction in the Coordinated System's EAEL over the Operating Year and shall distribute equally any compensating increase in the EAEL over all Periods in the Critical Period.

Subsection 6(c) Preliminary Regulation

Method 6(c)-1. Establishing Initial Offset(s)

This long-term method 6(c)-1. has the same term as the Agreement.

To carry out paragraph 6(c)(2), *Distribution of Energy Over the Critical Period*, the Study Group shall run the Preliminary Regulation to minimize the number of Offset Intervals and provide uniformity over the greatest number of contiguous Periods within the Critical Period. For the Critical Period, the day-weighted average of all Initial Offsets shall equal the difference between the day-weighted-average Coordinated System's EAEL and its day-weighted-average energy capability.

Subsection 6(e) Identification of Problems in the Preliminary Regulation

Method 6(e)-1. Communication of Problems in the Preliminary Regulation

This long-term method 6(e)-1. has the same term as the Agreement.

The Study Group shall notify all Parties about any problems associated with the Preliminary Regulation including, but not limited to, the following.

A. Shape of Hydroelectric Loads

Limitations pursuant to submethod 6(b)-1.C., *Adjustments to the Coordinated System's Estimated Adjusted Energy Loads for Use in the Preliminary Regulation*.

B. Non-shapeable Energy or Insufficient Energy

Period(s) or Operating Year(s) where the Coordinated System's EAEL(s) is exceeded because of Non-shapeable Energy Capability as described for the Modified Regulation in paragraph 6(h)(3), *Adjustment for Non-shapeable Energy Capability*, or cannot be met because of insufficient energy as described for the Modified Regulation in paragraph 6(h)(4), *Adjustments to Uniformly Distribute Surpluses or Deficits*.

C. Non-uniform Capability

Period(s) in which changes to the Coordinated System's EAEL(s) cannot be distributed uniformly.

Subsection 6(g) Adjustment of Estimated Adjusted Energy Loads Prior to Running the Modified Regulation

Method 6(g)-1. Responsibilities of the Study Group Prior to Running the Modified Regulation

This long-term method 6(g)-1. has the same term as the Agreement.

For purposes of this method 6(g)-1., references to Operating Year(s) mean an Operating Year or part thereof within the Critical Period.

Summary: The Study Group shall calculate DHGs for each Operating Year from data supplied under subsection 6(a), *Load and Firm Resource Data*, and as revised by subsection 6(f), *Modified Load and Firm Resource Data*, as provided below in submethod 6(g)-1.A. The Study Group shall then test the Coordinated System's EAELs to ensure compliance with applicable limitations on shifting by comparing the DHGs for each Operating Year as provided below in submethod 6(g)-1.B. If the Coordinated System's EAELs meet the shifting limitations, those EAELs shall be used in the Modified Regulation. If the EAELs do not meet the shifting limitations, the Coordinated System's EAELs and the EAELs of certain Parties shall be adjusted as provided below in submethod 6(g)-1.C.

A. Calculation of Desired Hydroelectric Generation

The Study Group shall calculate DHGs for each Operating Year from data supplied under subsections 6(a), *Load and Firm Resource Data*, and as revised by subsection 6(f), *Modified Load and Firm Resource Data*, by subtracting the Coordinated System's Net Non-hydroelectric Firm Resources from the Coordinated System's EAEL.

B. Estimated Adjusted Energy Loads that Need Not be Adjusted

1. Non-increasing Desired Hydroelectric Generations

So long as the calculated DHGs do not increase from one Operating Year to the next Operating Year throughout the Critical Period, the Study Group shall use in the Modified Regulation the EAELs submitted by the Parties under subsection 6(a), *Load and Firm Resource Data*, and as revised by subsection 6(f), *Modified Load and Firm Resource Data*.

2. Permissible Increasing Desired Hydroelectric Generations

If any increase in DHGs from one Operating Year to the next is less than or equal to the increase in the Coordinated System's EFEL between the same Operating Years, the Study Group shall use in the Modified Regulation the EAELs submitted by the Parties under subsection 6(a), *Load and Firm Resource Data*, and as revised by subsection 6(f), *Modified Load and Firm Resource Data*.

C. Adjustments to Estimated Adjusted Energy Loads

1. The Coordinated System's EAEL

If the increase in DHGs from one Operating Year to the next is more than the increase in the Coordinated System's average EFEL for the same Operating Years, the Study Group shall reduce the Coordinated System's EAEL by the lesser of (i) the amount by which the increase in the Coordinated System's EAEL exceeds the change in the Coordinated System's average EFEL (even if the change in EFEL is negative), or (ii) the amount by which the DHG increased for the Operating Years. The Study Group shall distribute equally any reduction in the Coordinated System's EAEL over the Operating Year and shall distribute equally any compensating increase in the EAEL over all Periods in the Critical Period.

2. Reductions in Individual Shifting Systems' Estimated Adjusted Energy Loads

The Study Group shall determine target EAEL(s) for the Shifting System(s) by adding the EAEL(s) of the Shifting System(s) and subtracting the reduction(s) to the Coordinated System's EAEL(s) computed under part 6(g)-1.C.1. above. The

Study Group shall develop new EAEL(s) for the Shifting System(s) to achieve the target EAEL(s) according to the Method Formula 6(g)-1. below.

Method Formula 6(g)-1.

$$EAEL_{ss} = ISA_{ss} + (TEAEL - ISA_{all})R_{ss}$$

Where, for each portion of the Operating Year within the Critical Period requiring a reduction,

$EAEL_{ss}$ = The adjusted EAEL of the individual Shifting System.

ISA_{ss} = The Initial Shift Allocation Level of the individual Shifting System.

TEAEL = The target EAELs for all Shifting Systems as computed under part 6(g)-1.C.2. above.

ISA_{all} = The sum of the Initial Shift Allocation Levels of all the individual Shifting Systems.

R_{ss} = The ratio of the Critical Period Energy Capability, in average megawatts, of the individual Shifting System to the sum of the Critical Period Energy Capabilities, in average megawatts, of all the individual Shifting Systems.

In carrying out these adjustments, the Study Group shall neither allocate a higher EAEL to a Shifting System than was in such Shifting System's original EAEL submission nor remove more than all submitted shift from any individual Shifting System's original EAEL submission.

3. Offsetting Increases in Shifting Systems' Estimated Adjusted Energy Loads

For Shifting Systems whose Critical Period EAELs were reduced under part 6(g)-1.C.2. above, the Study Group shall make uniform increases in those Shifting Systems' EAELs over the Critical Period to compensate for such reductions.

Subsection 6(h) Modified Regulation

Method 6(h)-1. Reestablishing Initial Offset(s)

This long-term method 6(h)-1. has the same term as the Agreement.

To carry out subparagraph 6(h)(1)(A), *Distribution of Energy Over the Critical Period*, the Study Group shall run the Modified Regulation to minimize the number of Offset Intervals and provide uniformity over the greatest number of contiguous Periods within the Critical Period. For the Critical Period, the day-weighted average of all Initial Offsets shall equal the difference between the average Coordinated System's EAEL and its average energy capability. The Study Group shall make uniform all Initial Offsets by allocating decreases to the Party's(ies)' EAEL(s).

Method 6(h)-2. Reductions to the Party's(ies') Estimated Adjusted Energy Load for Insufficient Generation After the Modified Regulation is Run

This long-term method 6(h)-2. has the same term as the Agreement.

Summary: The Study Group shall reduce the Coordinated System's EAEL(s) within an Offset Interval to obtain a uniform deficit or surplus among all Offset Intervals. For an Offset Interval requiring adjustment, the Study Group shall first reduce the Shifting System's(s') EAEL(s) as provided in submethod 6(h)-2.B. below. Changes to Shifting System's(s') EAEL(s) made under submethod 6(h)-2.B. are mandatory and shall not be subject to limitations specified in paragraph 6(f)(4), *Revisions to Load*. If further reductions are needed, the Study Group shall reduce the EAEL(s) in the Offset Interval of all Indicated Importing System(s) as provided in submethod 6(h)-2.C. below.

A. Uniform Deficit or Surplus Among Offset Intervals

After running the Modified Regulation, the Study Group shall reduce the Coordinated System's EAEL(s) within an Offset Interval to obtain a uniform deficit or surplus among all Offset Intervals as provided in submethods 6(h)-2.B. and 6(h)-2.C. below. If there is a surplus in any Offset Interval, all surpluses (and deficits, if any) shall be adjusted to equal the amount of the greatest surplus. If there are only deficits, the uniform deficit in all Offset Intervals shall be adjusted to equal the amount of the smallest deficit.

B. Reductions to Shifting Systems

The Study Group shall adjust the EAEL(s) of Shifting System(s) in each Offset Interval in the order that such Offset Interval(s) occurs in the Critical Period. In carrying out these adjustments, the Study Group shall neither allocate a higher EAEL to a Shifting System than was in such Shifting System's original EAEL submission nor remove more than all submitted shift from any individual Shifting System's original EAEL submission. The adjustment shall be determined according to the Method Formula 6(h)-1. below.

Method Formula 6(h)-1.

$$A_{6.b} = ((ISA_{ss} + (EAEL_{target} - ISA_{all})R_{ss}) - EAEL_{iss})R_{sai}$$

Where, for each Offset Interval,

$A_{6.b}$	=	Adjustment to be applied uniformly to the individual Shifting System's EAEL in the Offset Interval.
ISA_{ss}	=	The Initial Shift Allocation Level of the individual Shifting System.
$EAEL_{target}$	=	The necessary adjustment for the Shifting Allocation Interval, in average megawatts, subtracted from the sum of Shifting Systems' EAELs.
ISA_{all}	=	The Initial Shift Allocation Level of all the individual Shifting Systems that were identified for the Shifting Allocation Interval.
R_{ss}	=	The ratio of the Critical Period Energy Capability, in average megawatts, of the individual Shifting System to the sum of the Critical Period Energy Capabilities, in average megawatts, of all of the individual Shifting Systems.
$EAEL_{iss}$	=	The average EAEL of the individual Shifting System for the Shifting Allocation Interval.
R_{sai}	=	The ratio of the number of days in the Shifting Allocation Interval to the number of days in the Offset Interval.

C. Reductions for Indicated Importing Systems

If, after the adjustments provided for in submethod 6(h)-1.B. above are made, a remaining adjustment is needed for an Offset Interval, the Study Group shall reduce the EAEL(s) of all Indicated Importing System(s) as necessary. The Study Group shall identify for the Offset Interval all net Indicated Importing Parties and their net Indicated Imports. The reduction to such net Indicated Importing Parties shall be allocated pro rata to their net Indicated Imports during the Offset Interval. The adjustment to the EAELs of such net Indicated Importing Parties shall be determined according to the Method Formula 6(h)-2. below.

Method Formula 6(h)-2.

$A = ISF(R_{iip})$

Where, for each Offset Interval requiring a reduction,

A	=	The adjustment to be applied uniformly to the Indicated Importing Party.
ISF	=	The remaining reduction needed for the Offset Interval after the reduction of all Shifting Systems' EAELs.
R_{iip}	=	The ratio of the Indicated Importing Party's Indicated Import to the sum of all Indicated Importing Parties' Indicated Imports.

Subsection 6(n) Firm Energy Load Carrying Capability Outside of the Critical Period

Method 6(n)-1. Development of Pre-Critical Period Firm Energy Load Carrying Capability for Critical Periods Longer than One Year

This long-term method 6(n)-1. has a term of ten years from the Effective Date.

In Critical Periods longer than one year, the Study Group shall determine each Party's Firm Energy Load Carrying Capability ("FELCC") for each Period of the Operating Year that precedes the Critical Period as follows. The Study Group shall identify all Periods of the Operating Year that precede the Critical Period. The Study Group shall average each Party's Hydroelectric Firm Energy Load Carrying Capability ("Hydroelectric FELCC") in all Final Regulations run in past Operating Years that define the FELCC for each such Period in the current Operating Year. The Study Group shall then determine each Party's FELCC for each Period by adding the average Hydroelectric FELCCs of that Party and its non-hydroelectric Firm Resources for such Period.

Method 6(n)-2. Development of Post-Critical Period Firm Energy Load Carrying Capability for Critical Periods Longer than One Year

This long-term method 6(n)-2. has a term of ten years from the Effective Date.

In Critical Periods longer than one year, the Study Group shall determine each Party's FELCC for each Period of the Operating Year that follows the Critical Period as follows. The Study Group shall identify all Periods of the Operating Year between the end of the Critical Period and the end of the Operating Year. The Study Group shall add the residual Hydroelectric FELCCs for the

Coordinated System in all Final Regulations run in past Operating Years that define the FELCC for each such Period in the current Operating Year. The Study Group shall then identify each Party's FELCC for each Period using the Final Regulation with the minimum aggregate residual Hydroelectric FELCC for such Period.

Method 6(n)-3. Development of Pre-Critical and Post-Critical Period Firm Energy Load Carrying Capability for Critical Periods Less Than One Year

This long-term method 6(n)-3. has a term of ten years from the Effective Date.

In Critical Periods of less than one year, the Study Group shall determine each Party's FELCC for those Periods of the Operating Year that precede the Critical Period and those Periods that follow the Critical Period by using the following method 6(n)-3. For each Period of the Operating Year that is not in the Critical Period, the Study Group shall add each Party's (i) declared non-hydroelectric Firm Resources and (ii) hydroelectric capability. By July 1, the Study Group shall determine such hydroelectric capability from a hydroelectric regulation performed in the following manner.

A. Hydroelectric Regulation Used to Determine Non-Critical Period Capability

The Study Group shall run reservoir regulations similar to those made pursuant to subparagraph 7(d)(4)(A), *Trial Refill Regulation Based on Minimum Flow Variable Energy Content Curves*, except that the regulations shall (i) start on the first Period of the Critical Period and run for 12 months, (ii) initialize all reservoirs to the same elevation as at the start of the Critical Period in the Final Regulation, (iii) run to the Coordinated System's FELCC for Periods within the Critical Period, and (iv) regulate the Coordinated System after the Critical Period to refill consistent with all non-power requirements.

B. Selection and Distribution of Hydroelectric Capability

The Study Group shall add the Coordinated System's hydroelectric generation from each Period outside the Critical Period for each year and select the fifth percentile value, in megawatt months, of the sums (*e.g.*, the third lowest for 60 years). The Study Group shall distribute the value, in megawatt months, selected under the preceding sentence in proportion to the Period-by-Period average of the non-Critical Period Periods that comprise the lowest tenth percentile of such sums.

C. Allocation of Hydroelectric Capability to the Parties

For each Period outside the Critical Period, the Study Group shall determine the hydroelectric capability attributed to each Party using the Method Formula 6(n)-1. below.

Method Formula 6(n)-1.

$$HC_p = (AHC_p / AHC_{CS})HC_{CS}$$

Where, for each non-Critical Period Period,

HC_p = Hydroelectric capability attributed to a Party for such Period.

AHC_p = Average hydroelectric capability of all the years attributed to a Party for such Period.

AHC_{CS} = Average hydroelectric capability of all the years attributed to the Coordinated System for such Period.

HC_{CS} = Hydroelectric capability attributed to the Coordinated System for such Period.

Subsection 6(o) Load Determination Re-Regulation

Method 6(o)-1. Load Determination Re-Regulation Process

This long-term method 6(o)-1. has the same term as the Agreement.

No later than August 15, the Study Group shall prepare a Load Determination Re-Regulation ("LDR") in order to adjust planned Firm Load Carrying Capability ("FLCC") to conform to certain information about hydroelectric Firm Resources submitted during the initial planning process to current conditions. The Study Group shall prepare an LDR each year; *provided* if the first year of the Critical Period is established for purposes of the current Operating Year, the Final Regulation shall be considered the LDR. The Study Group shall prepare for and run the LDR according to submethods 6(o)-1.A., 6(o)-1.B., and 6(o)-1.C. below, adjust the Parties' FELCCs according to submethod 6(o)-1.D. below, and determine a new Firm Peak Load Carrying Capability ("FPLCC") according to submethod 6(o)-1.E. below.

A. Identify the Final Regulation to be used for the Load Determination Re-regulation

Compute the Coordinated System's Storage Energy based upon the end-of-July rule curves for each Final Regulation performed under the Agreement or the Comprehensive Agreement that contains the immediately preceding July 31. Then compare such Storage Energies to the Storage Energy of the end-of-July Actual Energy Regulation Ending Elevation ("AER EE") contained in the final Controlling Actual Energy Regulation ("Controlling AER") for the immediately-preceding Operating Year. The Final Regulation whose Storage Energy is numerically nearest to the Storage Energy of such AER EE shall then be used for purposes of the Load Determination Re-regulation ("LDR Base Regulation").

B. Update Load Determination Re-regulation Base Regulation to Reflect Changes to Firm Resource Capability

Except for changed capability due to the withdrawal of Excluded Firm Resources during the first four Operating Years after the Effective Date, update the input parameters of the LDR Base Regulation for all changes of capability of Firm Resources submitted in the current planning process pursuant to section 6, *Determination of Firm Load Carrying Capability*, including the following.

1. Project Characteristics

Changes, additions, and deletions of Project characteristics including plant data and submitted non-power requirements; *provided* if a Party submits a change to a non-power requirement after the submission of preliminary data in the current subsection 6(a), *Load and Firm Resource Data*, planning process, the Coordinating Group must agree in order for the changes to be reflected in the LDR.

2. Hydroelectric Maintenance

Changes to hydroelectric maintenance.

3. Non-hydroelectric Firm Resources

Changes, additions, and deletions of non-hydroelectric Firm Resources including maintenance.

C. Regulation

Run the LDR Base Regulation using the updated input data. Regulate reservoirs using their respective rule curves as well as the streamflow data from the LDR Base Regulation consistent with non-power requirements.

D. Firm Energy Load Carrying Capability Adjustments

Adjust individual Party's FELCCs to reflect any changes in capability between the established FELCCs and the energy capabilities resulting from submethod 6(o)-1.C. above.

E. Firm Peak Load Carrying Capability Determination

Input new project peak data to the FPLCC determination made pursuant to subparagraph 6(h)(6)(B), *Determination of Firm Peak Load Carrying Capability*.

Method 6(o)-2. Adjustment to Reflect Exclusion of Firm Resources

This long-term method 6(o)-2. has a term of five years commencing on the Effective Date.

Summary: Withdrawing Parties do not coordinate all of the same Projects under this Agreement as under the Comprehensive Agreement. Because of this, for a period of four years after the Effective Date the Coordinated System's final planned FLCC determined in subsection 6(o), *Adjustments to Established Firm Load Carrying Capabilities*, may include the planned capability of Excluded Firm Resources. The Withdrawing Parties agree to meet the planned obligations relating to their Excluded Firm Resources in this situation as follows.

During the first four Operating Years following the Effective Date, the Study Group shall not adjust the LDR Base Regulation to reflect the withdrawal of the Excluded Firm Resources. During those same four Operating Years, the Study Group shall reduce a Withdrawing Party's FLCC in each Period of the Operating Year in an amount equal to the planned capability of its Excluded Firm Resources in the corresponding LDR Base Regulation. The Study Group shall make such reductions no later than August 15 of each Operating Year. If the Study Group reduces any Withdrawing Party's FLCC in any Period lower than zero, such Party shall be obligated to deliver Interchange Energy up to the amount of such negative FLCC upon the request of a Party with the right to receive Interchange Energy under subsection 9(d), *Interchange Energy*. During the relevant Operating Year the Excluded Firm Resources are not included in the AER. The Withdrawing Party's obligation to deliver Interchange Energy under this method 6(o)-2. shall be in addition to any other obligation under subsection 9(d), *Interchange Energy*.

Subsection 6(p) Exchange of Firm Energy Load Carrying Capability

There are currently no long-term methods relating to this subsection.

Section 7 Determination of Base and Variable Energy Content Curves

Subsection 7(d) Variable Energy Content Curves

Method 7(d)-1. Other-than-Monthly Values

This long-term method 7(d)-1. has the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this method 7(d)-1. shall also be rescinded.

As provided in part 9(b)-3.A.2., *Input Data*, the Parties may use other-than-monthly values for Variable Energy Content Curves ("VECC") used with the Actual Energy Regulation ("AER").

Method 7(d)-2. Trial Refill Regulation

This long-term method 7(d)-2. has the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this method 7(d)-2. shall also be rescinded.

The Parties shall use the July 31 Actual Energy Regulation Ending Elevations (“AER EE”) from the finalized Controlling Actual Energy Regulation (“Controlling AER”) of the previous Operating Year as the Coordinated System’s assumed reservoir elevations for each August 1 of the Historical Period of Record for the refill regulations performed pursuant to paragraph 7(d)(4), *Refill Regulations*.

Method 7(d)-3. Methods and Procedures for the Refill Regulation

This long-term method 7(d)-3. has the same term as the Agreement. A Refill Regulation shall be made based on the Final Regulation in accordance with section 7, *Determination of Base and Variable Energy Content Curves*. The Refill Regulation is completed to reduce the refill failures caused by producing non-firm energy, thereby protecting the Coordinated System’s ability to produce next year’s Firm Energy Load Carrying Capability (“FELCC”).

Compliance with this requirement is verified by the Project owners each year through hydroelectric-regulation studies based on the following method 7(d)-3.

A. Refill Regulation Priorities

The Refill Regulation shall be run to meet the following objectives in the priority set forth below.

1. Meet Firm Energy Load Carrying Capability

First, regulate to meet current-year FELCC.

2. Refill for Future Firm Energy Load Carrying Capability

Second, regulate to refill in accordance with section 7, *Determination of Base and Variable Energy Content Curves*.

3. Produce Optimum Secondary Energy

Third, regulate to produce secondary energy consistent with the first and second priorities above and subsection 4(b), *Priorities*.

B. Refill Test Failure

Pursuant to subparagraph 7(d)(4)(B), *Refill Regulation*, the study fails the "refill test" when (i) more than five percent of the years in the Historical Period of Record fail to refill the Coordinated System's Storage Energy in accordance with subparagraph 7(d)(4)(B), *Refill Regulation*, on July 31, and (ii) secondary generation was produced at any time during the preceding January through July, irrespective of Periods modified pursuant to paragraph 6(h)(3), *Adjustment for Non-shapeable Energy Capability*. These refill test requirements are clarified and limited by the following.

1. Definition of Five Percent

The "five percent" referred to above shall mean three years when the Historical Period of Record is 60 years or 70 years and four years when the Historical Period of Record is 80 years.

2. Increasing the Assured Refill Curves and the Variable Energy Content Curves

The Assured Refill Curves ("ARCs") or VECCs shall be increased until the refill test is met, or the increases no longer raise the Coordinated System's July 31 Storage Energy.

3. Storage Above Full

Any storage above full elevations in Coordinated System reservoirs on July 31 shall not be included in the Coordinated System's July 31 Storage Energy computation detailed in part 7(d)-3.B.4. below.

4. Calculation of Full Coordinated System Storage Energy

For purposes of subparagraph 7(d)(4)(B), *Refill Regulation*, the Coordinated System's maximum storage capability measured in Storage Energy shall reflect Coordinated System reservoirs at full. The yearly Coordinated System Storage Energy shall reflect Coordinated System reservoirs on July 31 in the Refill Regulation, except as follows.

a. Usable Treaty Storage

Mica's and Arrow's Storage Energies shall be based on usable Treaty Storage.

b. Mica Full Content

Mica's full Storage Energy shall be based upon the July 31 Target Content as dictated by the Assured Operating Plan ("AOP"). If the

Project is below that content due to minimum flow or Mica Target Flows, that deficit shall be measured against the Mica Target Content. No storage above the target content shall be included in the refill calculation.

c. Brownlee Storage

Brownlee's storage shall not be included in the calculation of the Coordinated System's Storage Energy.

d. Kootenay Lake Storage

Kootenay Lake's storage shall not be included in the calculation of the Coordinated System's Storage Energy.

e. Non-Treaty Storage

Non-Treaty Storage shall not be included in the calculation of the Coordinated System's Storage Energy.

C. Modeling

The hydroelectric-regulation model and data base shall simulate the operation of the AER. The input criteria and data base shall include the following.

1. Canadian Option

If the Canadian Entity requests that the Refill Regulation incorporate a fixed AOP operation then subpart 7(d)-3.C.1.a. below shall be used to model Treaty Storage, otherwise subpart 7(d)-3.C.1.b. below shall be used.

a. Fixed Operation

Mica, Arrow, and Duncan operations shall be fixed based on the current AOP non-power requirements, rule curves, and power discharge requirements, along with any changes agreed to by both the United States Entity and the Canadian Entity to be included into the Detailed Operating Plan ("DOP"). With this information a Treaty Storage regulation ("TSR") is performed which yields reservoir elevations for Treaty Storage. Treaty Storage and all other reservoirs shall start the current TSR at their previous year's July 31 TSR elevations.

b. Regulated Operation

Mica shall operate to its AOP target outflows with Arrow attempting to balance the difference between the outflows requested by the model and the Mica targets. If Arrow is unable to balance the Mica operation, the difference is reflected in the flow at the border. The Power Discharge Requirements ("PDRs") for Treaty Storage shall be initialized to the

AOP levels. The ARCs and VECCs shall be adjusted to increase the Coordinated System's July 31 Storage Energy.

2. Brownlee Operation

Brownlee shall operate to the most recent target elevations, supplied by Idaho Power Company, for all years of the study.

3. Surplus Method

In Operating Years when lower limits to the VECCs ("LLVECC") are established by the Coordinating Group, the "surplus method" shall be used during the Periods January through April 15. The surplus method uses the LLVECC whenever the Coordinated System is generating energy in excess of FELCC. The regulation shall be run first to the LLVECCs. If FELCC is not met and the VECC at any Project is lower than its LLVECC, then the LLVECCs at any such Projects shall be adjusted towards their calculated VECCs until FELCC is met. If FELCC is still not met, then all Projects shall be proportionately drafted from their VECCs until FELCC is met.

D. Principles for Adjusting Power Discharge Requirements

For each year that fails to pass the refill test the following steps shall be followed to enhance refill after the PDRs are initialized to minimum flows. The PDRs for Treaty Storage shall be as defined in subpart 7(d)-3.C.1.a. or 7(d)-3.C.1.b. above.

1. Increase Power Discharge Requirements Uniformly

At Projects that did not refill and are not restricted, PDRs shall be increased uniformly to raise such Projects' VECCs up to the Base Energy Content Curves ("Base ECC") or flood control. (This first step can be done for all Projects that failed to refill because this step usually does not reduce the number of failures or eliminate the secondary energy produced.)

2. Raise the Assured Refill Curves and the Variable Energy Content Curves Together

If part 7(d)-3.D.1. above is not sufficient to pass the refill test in a particular year, identify the Projects that failed to refill, are not restricted, and for which the Project owner is surplus. Raise the VECCs and ARCs of such Projects together until the refill test is met or each individual Project is restricted from filling further or is full.

3. Further Raises to the Power Discharge Requirements

If part 7(d)-3.D.2. above is not sufficient to pass the refill test in a particular year, then repeat the step contained in part 7(d)-3.D.2. above on the remaining Projects that failed to refill. If these modifications to the PDRs are sufficient to pass the refill test, then reduce PDRs to the lowest flows sufficient to pass the refill test. If these modifications to the PDRs are not sufficient to pass the refill test, then increase PDRs until there is an insignificant (less than 100 average megawatt) increase in the Coordinated System's Storage Energy.

The refill test is completed when the requirements defined in subparagraph 7(d)(4)(B), *Refill Regulation*, are satisfied.

Section 8 Maintenance and Reserves

Subsection 8(a) Maintenance

Method 8(a)-1. Maintenance Outages

This method 8(a)-1. shall have the same term as the Agreement.

For all Coordinated System regulations, the Parties shall adjust maximum generation and maximum turbine discharge to reflect hydroelectric Maintenance Outages, submitted pursuant to paragraph 6(a)(4), *Maintenance*, and updated as appropriate pursuant to paragraph 6(f)(3), *Revisions to Maintenance*.

Subsection 8(b) Forced Outage Reserves

Method 8(b)-1. Forced Outage Rates

This long-term method 8(b)-1. has the same term as the Agreement; *provided* upon demonstration by any Party within five years after the Effective Date that such Party is being adversely affected by this method 8(b)-1. or its implementation, such method 8(b)-1. shall, at such Party's request, be reopened and re-negotiated.

No later than April 1 each Operating Year, the Parties shall submit to the Study Group pursuant to paragraph 6(f)(5), *Forced Outage Rates*, Forced Outage Rates based on actual, unit-specific information as identified in submethods 8(b)-1.A. and 8(b)-1.B. below. For units with five or more years of operating history, the Parties shall use a five-year rolling average of such data. For units with three or four years of operating history, the Parties shall base unit-specific Forced Outage Rates on the available period of record. For non-combustion turbine units with less than three years of operating history, the Parties shall base Forced Outage Rates on North American Energy Reliability Council ("NERC") Generator-Availability Data System ("GADS") class-average data for units of similar type and size. For combustion turbines with less than three years of operating history, the Parties shall set such unit's Forced Outage Rates to equal 150 percent of (one minus NERC's starting reliability, as specified in NERC's *Generating Availability Report 1991 - 1995*, or the most recent update of this document by NERC).

A. Units of Fifty Megawatts or Larger

For units of 50 megawatts or larger, NERC GADS equivalent Forced Outage Rates ("EFORS") for specific units shall be used where available. Where NERC GADS data is not available, Parties may submit Forced Outage Rates for specific units computed consistent with NERC GADS methodology. Where no unit-specific data is provided, 1.5 times NERC GADS class-average EFORs for units of similar type and size shall be used.

B. Units Less than Fifty Megawatts

For units of less than 50 megawatts, NERC GADS EFORs for specific units may be used where available. Where NERC GADS data is not available, Parties may submit Forced Outage Rates for specific units computed consistent with GADS methodology. Where no unit-specific data is provided, NERC GADS class-average Forced Outage Rates for units of similar type and size shall be used.

Section 9 Operating Procedures, Obligations, and Rights

Subsection 9(b) Actual Energy Capability

Procedure 9(b)-1. Use of the Actual Energy Regulation to Determine Actual Energy Capability

This long-term procedure 9(b)-1. has the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure 9(b)-1. shall also be rescinded.

An Actual Energy Regulation ("AER") shall be used to fulfill the purposes of subsections 9(b), *Actual Energy Capability*, and 9(g), *Operation of Reservoirs Below Energy Content Curves and Critical Rule Curves,* providing the Parties with a coordinated determination of their individual Initial Actual Energy Capabilities ("Initial AEC") and Actual Energy Regulation Ending Elevations ("AER EE"). The Parties shall use each Controlling Actual Energy Regulation ("Controlling AER") both prospectively (to determine upcoming rights and obligations and draft points) and retroactively (to finalize previous Periods).

The Study Group shall run the Controlling AER within eleven calendar days following the end of each Period. Each Party shall then determine its Actual Energy Capability ("AEC") by adjusting its Initial AEC as follows.

A. Adjustments for Interchange Energy

Except for deliveries or receipts of Interchange Energy under paragraph 9(d)(2), *Over-receipt of Interchange Energy*, increase its Initial AEC for receipts of Interchange Energy and Holding Energy ("HE") and decrease its Initial AEC for deliveries or returns of Interchange Energy and HE.

B. Adjustments for Secondary Energy or Spill

Reduce its Initial AEC for generation not requested as Interchange Energy that (i) could not be stored in Coordinated System reservoirs, and (ii) was used as secondary energy or was spilled.

C. Adjustments for non-Actual Energy Regulation Flexibility

Modify its Initial AEC to reflect paragraph 9(k)(2), *Effect of Adjustments on Other Provisions/Demonstration of Ability to Support Adjustments with Critical Period Streamflows*, Firm Energy Load Carrying Capability ("FELCC") decreases or subsequent corresponding increases not reflected in the AER; *provided* such modifications shall not alter Interchange Energy rights and obligations. Such decreases of FELCC shall result in decreases in AEC and subsequent corresponding increases of FELCC shall result in increases in AEC.

Procedure 9(b)-2. Estimated Actual Energy Capabilities to be Used by the Study Group

This long-term procedure 9(b)-2. has the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure 9(b)-2. shall also be rescinded.

The Study Group shall calculate estimates of each Party's Initial AEC for the Parties' use in determining rights and obligations for operating purposes during the current Period. The Study Group shall estimate Initial AECs for the current Period or any part thereof by projecting the AER using estimated data in the manner set forth in procedure 9(b)-3., *Actual Energy Regulation*. The Parties shall use consistent estimates for all operating purposes.

Procedure 9(b)-3. Actual Energy Regulation

This long-term procedure 9(b)-3. has the same term as the Agreement.

A. Simulation of Firm Resources in the Actual Energy Regulation

The AER shall be run as follows.

1. General

a. Continuous Hydroelectric-System Simulation

At least twice a month the Study Group shall prepare a continuous hydroelectric-system simulation with input data from both Period and Subperiod quantities as detailed in part 9(b)-3.A.2. below.

b. Starting Elevations

The starting reservoir elevations for the first Period of the Operating Year shall be the AER EEs of the last Period in the Controlling AER of the preceding Operating Year. The Study Group shall simulate each

Subperiod with each reservoir starting from the AER EE determined for the previous Subperiod.

c. Purpose of the Controlling AER

The Controlling AER (i) establishes Initial AECs for the Parties' use in determining Interchange Energy rights and obligations, and (ii) determines the AER EE. The Controlling AER shall be based upon the most recent Conservative Streamflow Estimates and shall incorporate Unplanned Non-power Requirements submitted pursuant to procedure 9(b)-4., *Actual Energy Regulation for Purposes of an Unplanned Non-power Requirement*, as well as requested Flexibility Adjustments permitted under procedure 9(b)-5., *Actual Energy Regulation for Purposes of a Flexibility Request*.

2. Input Data

In accordance with the annual procedures, the Parties shall submit timely to the Study Group (i) most probable forecasts of Unregulated Streamflows, non-power requirements, Variable Energy Content Curves ("VECC"), and variable flood control curves by Subperiod, and (ii) all other input data required for completion of the regulation by Period. VECCs and variable flood control curves for Projects from the date of submission to the end of the Operating Year shall be determined and submitted by the responsible Reservoir Party using Conservative Streamflow Estimates. The Study Group shall use this and other input data in the regulation as follows.

a. Project Data

At the start of the Operating Year the Study Group shall convert data and data methodologies submitted by Period to data and methodologies suitable for Subperiods and incorporate into the AER the hydroelectric plant characteristics, non-power requirements, and bypass flow methodologies that were used in the Load Determination Re-regulation ("LDR").

b. Update Conservative Streamflow Estimates

The Study Group shall update the Conservative Streamflow Estimates for all Projects based upon the streamflow data submitted by the Parties. If updated streamflow data are not submitted, the latest Conservative Streamflow Estimates shall be used.

c. Update Variable Energy Content Curves

The Study Group shall incorporate the VECCs and the variable flood control curves submitted by the responsible Reservoir Parties. If a Reservoir Party does not submit updated VECCs and variable flood control curves for any of its Projects, the Study Group shall use the latest VECCs and variable flood control curves for such Project(s).

d. Critical Rule Curves

At the start of the Operating Year the Study Group shall, consistent with non-power requirements, incorporate into the AER the Critical Rule Curves ("CRC") established pursuant to subsection 6(l), *Determination of Critical Rule Curves,* for each Period of such Operating Year.

e. Non-hydroelectric Firm Resources

At the start of the Operating Year the Study Group shall incorporate into the AER, for each Period of such Operating Year, the energy capabilities for all non-hydroelectric Firm Resources and hydroelectric miscellaneous Firm Resources, before adjustment for planned Maintenance Outages, as such Firm Resources were submitted pursuant to subsection 6(a), *Load and Firm Resource Data,* and as later modified pursuant to subsection 6(f), *Modified Load and Firm Resource Data.* Restoration shall not be included as a Firm Resource.

f. Non-hydroelectric Firm Resource Maintenance Outages

At the start of the Operating Year the Study Group shall convert planned non-hydroelectric Firm Resource Maintenance Outages from the LDR by Period to data suitable for Subperiods and incorporate into the AER the energy equivalent of such planned non-hydroelectric Firm Resource Maintenance Outages.

g. Firm Energy Load Carrying Capability

At the start of the Operating Year the Study Group shall incorporate into the AER, for each Period of such Operating Year, the FELCC for each Party for each Period as reflected in the LDR. The Study Group shall adjust such FELCC in the AER for Flexibility Adjustments made pursuant to procedure 9(b)-5., *Actual Energy Regulation for Purposes of a Flexibility Request*. Except as provided in such procedure 9(b)-5., the Parties shall not return a Flexibility Adjustment from the first Subperiod of a Period in the second Subperiod of that Period. The Parties may also dedicate FELCC to refill pursuant to procedure 9(b)-6., *Foregoing Firm Energy Load Carrying Capability to Influence Refill in the Actual Energy Regulation*.

3. Simulation

a. Modeling Principles

The Study Group shall run the AER in accordance with the *Principles of Modeling Non-power Requirements in the Actual Energy Regulation* found in Attachment 1 pursuant to procedure 5(a)-2., *Modeling Attachment*.

b. Hydroelectric-Independent Projects

For Projects not subject to paragraph 9(g)(3), *Proportional Draft*, (including but not limited to the Brownlee project and the Willamette Projects), the Study Group shall base simulations upon estimates of actual operations.

c. Hydroelectric Maintenance

In preparing the AER the Study Group shall reflect planned hydroelectric Maintenance Outages by adjusting maximum generation.

d. Requested Spill to Reach Energy Content Curve

Whenever a Reservoir Party provides a reasonable forecast under paragraph 9(j)(2), *Conservation of Energy*, indicating that spill at any of its reservoirs is necessary to reach the Adjusted Energy Content Curve ("Adjusted ECC") by the end of the Drawdown Period such Reservoir Party may require the Study Group to reflect such reservoir's(s') spill in the AER; *provided* if needed the Coordinating Group shall determine how to reflect such spill in the AER.

e. Identifying Potential Difficulties

The Study Group shall include in the AER and simulate all Subperiods through the end of the current Operating Year to allow the Parties to identify potential difficulties regarding non-power requirements, the development of FELCC, and refill. The Study Group shall only adjust or revise the AER to mitigate such difficulties pursuant to procedures 9(b)-4., *Actual Energy Regulation for Purposes of an Unplanned Non-power Requirement*, and 9(b)-5., *Actual Energy Regulation for Purposes of a Flexibility Request*. The Study Group shall only take further corrective action upon the agreement of the Coordinating Group. The Study Group shall distribute to the Parties summaries of Project operations resulting from the AER.

4. Effectiveness

The Study Group shall inform the Parties of updated Initial AECs and AER EEs in the most expeditious manner and in the shortest possible time. The AER shall become effective as the Controlling AER for purposes of determining AECs and prescheduling energy transactions on the first business day following the day the Study Group communicates such Initial AECs and AER EEs to the Parties. The information shall be considered to be communicated the following day if communication is not initiated by 1600 hours.

5. Revisions

Within one business day after the Controlling AER becomes effective, any Party may require that the Study Group correct such AER if it contains computational or data-entry errors not caused by that Party. The Study Group shall correct such error and communicate the corrected results in the shortest possible time. The Controlling AER shall remain in effect until the corrected AER becomes effective pursuant to part 9(b)-3.A.4. above; *provided* that if the communication of the corrected AER is initiated prior to 0600 hours the Parties shall consider the corrected AER to have been communicated on the previous business day for purposes of part 9(b)-3.A.4.

B. Use of the Actual Energy Regulation to Determine Interchange Rights and Obligations

The Parties shall use the latest estimate of their Initial AECs from the Controlling AER for any Subperiod and adjust such Initial AECs pursuant to procedure 9(b)-1., *Use of the Actual Energy Regulation to Determine Actual Energy Capability*, to determine their Interchange Energy rights and obligations during such Subperiod. After finalization of a Period, each Party shall make the appropriate adjustments to its Initial AEC (determined in the finalized Controlling AER) pursuant to procedure 9(b)-1., *Use of the Actual Energy Regulation to Determine Actual Energy Capability*, and shall return excess Interchange Energy for each Period pursuant to paragraph 9(d)(2), *Over-Receipt of Interchange Energy*, as appropriate; *provided* the Parties shall consider all Subperiods in a Period in determining whether excess Interchange Energy has been delivered to a Party.

C. Insufficient Exports to Supply Coordinated System Imports

When the current Period of the Controlling AER has a net sum of Interchange Energy imports and exports that is negative, the following parts 9(b)-3.C.1. and 9(b)-3.C.2. shall apply.

1. Return of Flexibility

Any Party whose Flexibility Adjustment Account ("FAA") is positive pursuant to subsection 9(k), Adjustments in Firm Energy Load Carrying Capability During Operating Year, shall return any outstanding balance in the current Period to the extent needed to put the Coordinated System in balance and in proportion to the total Coordinated System's outstanding flexibility.

2. Return of Interchange

A Party may request the return of Interchange Energy only to the extent needed to meet its firm load assuming the use of declared Firm Resources and limiting such request by its Indicated Import in the deficit Period. A Party shall prorate its requests for return of Interchange Energy to any Party that has an outstanding balance relating to Interchange Energy deliveries from the requesting Party based upon the outstanding balances of all such Parties with the requesting Party.

D. Use of Actual Energy Regulation Ending Elevation to Determine Rights and Obligations

In making the calculations on a Subperiod basis pursuant to subpart 9(j)-2.C.7.b., *Daily Interpolations of Energy Content Curves*, (which effectuates subsection 9(j), *Release of Water from Storage and In Lieu Energy Deliveries*), and for the purpose of determinations under subsections 9(g), *Operation of Reservoirs Below Energy Content Curves and Critical Rule Curves*, and 9(l), *Provisional Energy*, the Parties shall use the lower of the Adjusted ECC or the AER EE from the Controlling AER as the Energy Content Curve ("ECC"). The Parties shall construe all references in the Agreement to end-of-Period elevations to mean the AER EE of the last Subperiod of a Period. If a Party believes that it has been adversely affected by this subprocedure 9(b)-3.D. or the implementation of this subprocedure 9(b)-3.D. as it relates to subsection 9(l), *Provisional Energy*, this subprocedure 9(b)-3.D. shall, at such Party's request, be reopened and reconsidered.

Procedure 9(b)-4. Actual Energy Regulation for Purposes of an Unplanned Non-power Requirement

This long-term procedure 9(b)-4. has the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure 9(b)-4. shall also be rescinded.

Summary: When a Party submits an Unplanned Non-power Requirement, the Study Group runs a Trial Unplanned Non-power Requirement Actual Energy Regulation ("Trial UNPR AER") and compares it against a Base Unplanned Non-power Requirement Actual Energy Regulation ("Base UNPR AER") to see whether the Coordinated System can absorb the impacts of the Unplanned Non-power Requirement. The Base UNPR AER for purposes of Unplanned Non-power Requirements is the last Controlling AER with updated Conservative Streamflow Estimates and all Unplanned Non-power Requirements removed. The Trial UNPR AER is a re-regulation of the last Controlling AER (including non-power requirements) after it is updated for actual streamflows and new Conservative Streamflow Estimates and to include the currently submitted Unplanned Non-power Requirement and previously submitted Unplanned Non-power Requirements which did not have an impact on the AER.

If the comparison of the Base and Trial UNPR AERs demonstrates that the Coordinated System cannot absorb the impact of a requirement, the Trial Unplanned Non-power Requirement Actual Energy Regulation Re-regulation ("Trial UNPR AER Re-regulation") is then used to calculate a Maximum Generation Impact that defines the impact to the Coordinated System resulting from the Unplanned Non-power Requirement. The Unplanned Non-power Requirement is placed into the Controlling AER, together with a Generation Impact as a substitute resource of the Coordinated System, and, to the extent it cannot subsequently be reduced by the Coordinated System's surplus, the Generation Impact may result in the inability of some Parties that are Interchange Energy importers to obtain sufficient Interchange Energy to supply their FELCC.

A Reservoir Party may choose not to submit a non-power requirement that satisfies the definition of an Unplanned Non-power Requirement even though the non-power requirement is being physically implemented. In such a case, the Agreement is implemented as if the non-power requirement did not exist. The Coordinating Group shall resolve how to treat an ad hoc non-power requirement that does not meet the definition of an Unplanned Non-power Requirement on a case by case basis, using the principles of subsection 9(h), *Priorities on Use of Facilities for Power*.

A. Scope

1. Unplanned Non-power Requirements

These procedures may be used when a Submitting Party physically implements an Unplanned Non-power Requirement during the Operating Year. In order to use these procedures, the Submitting Party must submit the Unplanned Non-power Requirement into planning for the following Operating Year pursuant to section 6, *Determination of Firm Load Carrying Capability.* If a Requesting Party chooses not to use this procedure, all rights and obligations under the Agreement shall remain as if the non-power requirement had not been implemented.

2. Modifications to Non-power Requirements

To the extent that the characteristics of a non-power requirement (both submitted and Unplanned Non-power Requirements) are different when implemented than when submitted, at the request of the Submitting Party the Study Group shall make appropriate prospective modifications to the non-power requirement by making revisions to the requirement in the AER pursuant to this procedure following the notification of such modification. The Reservoir Party may require the Study Group to run an Expedited Trial Unplanned Non-power Requirements Assessment ("Expedited UNPR Assessment") pursuant to subprocedure 9(b)-4.D. below to reflect such modification in an expedited manner.

3. Unsubmitted Non-power Requirements

If a Submitting Party does not submit a non-power requirement in the section 6, *Determination of Firm Load Carrying Capability*, planning process that it knew of prior to February 1 during the planning process that resulted in the operating plan for the current Operating Year, such requirement cannot be treated as an Unplanned Non-power Requirement or as an ad hoc non-power requirement pursuant to part 9(b)-3.A.1. above and part 9(b)-3.B.2. below, unless the Parties mutually agree otherwise.

4. Ad Hoc Non-power Requirements that do not Qualify as Unplanned Non-power Requirements

The Coordinating Group shall, on a case-by-case basis, resolve how to treat an ad hoc non-power requirement that does not meet the definition of an Unplanned Non-power Requirement based on the following. Stated generally, available energy capabilities of the Parties' Firm Resources should be used first to develop their owner or operator's FELCC, second to develop other Parties' FELCC, third to meet their owner or operator's secondary purposes, and fourth to meet other Parties' secondary purposes.

B. Notice and Submittal Guidelines

1. Notification of All Parties

The Requesting Party shall notify all Parties of an impending Unplanned Non-power Requirement as soon as possible after the Requesting Party has learned of the requirement. The information shall be disseminated to the Parties through the Study Group at the request of the Requesting Party. The notice shall include the Requesting Party's best estimate of the elements of the Unplanned Non-power Requirement as well as the estimated date it will be implemented. It is not the intent of this provision that information regarding an Unplanned Non-power Requirement be withheld for lack of clarity of details.

2. Submission for Inclusion in the Actual Energy Regulation

The Requesting Party shall submit the Unplanned Non-power Requirement to the Study Group for analysis and the Study Group shall include the Unplanned Non-power Requirement in the AER pursuant to subprocedure 9(b)-4.C. below.

3. Notification from Study Group

Once the Study Group receives the necessary information it shall process all Unplanned Non-power Requirements in the shortest possible time pursuant to subprocedure 9(b)-4.D. below. After its studies are complete, the Study Group shall notify the Parties of the results by the agreed notification procedures. The notice shall contain a description of the Unplanned Non-power Requirement, including a narrative of the implementation process, a statement of whether the submittal of the Unplanned Non-power Requirement has resulted in a modification to the Controlling AER, and the newly applicable Maximum Generation Impact, if appropriate.

C. Inclusion of an Unplanned Non-power Requirement in the Actual Energy Regulation

Upon the receipt of an Unplanned Non-power Requirement, the Study Group shall prepare a Base UNPR AER and a Trial UNPR AER to determine the impacts of the Unplanned Non-power Requirement. To prepare the Trial UNPR AER, the Study Group shall rerun the Controlling AER to include updated actual streamflows, updated Conservative Streamflow Estimates, and the Unplanned Non-power Requirement and, to the extent they are not already included in the Controlling AER, all planned non-power requirements and Unplanned Non-power Requirements previously submitted under this procedure, including those which when submitted did not impact a previous Trial UNPR AER. So long as the total Coordinated System's generation remains the same for all Periods and all participating Reservoir Parties and Parties downstream of affected reservoirs agree, the Study Group may include reservoir-balancing arrangements with prospective application in the AER; *provided* the Study Group shall only implement reservoir-balancing arrangements by adjusting rule curves at the participating Projects or by some other mutually acceptable mechanism.

1. Satisfaction of Recovery Criteria

If the Trial UNPR AER meets the Recovery Criteria, the Study Group shall rerun the Controlling AER to include the Unplanned Non-power Requirement, which updated regulation shall become the Controlling AER.

2. Addition of Maximum Generation Impact to Satisfy Recovery Criteria

If the Recovery Criteria is not met, the Study Group shall run a Trial UNPR AER Re-regulation to determine the maximum amount and placement of additional resources needed in order to develop the AEC indicated in the Base UNPR AER of the Coordinated System during the remaining Operating Year ("Maximum Generation Impact") as follows.

a. Determination of Maximum Generation Impact

The Maximum Generation Impact shall be the amount of additional generation needed in the Trial UNPR AER Re-Regulation to meet the Recovery Criteria. The Study Group shall run the regulation to move the Maximum Generation Impact as late as possible in the Operating Year.

b. Actual Energy Regulation Generation Impact

The Study Group shall include the Coordinated System's Maximum Generation Impact in the AER as an additional miscellaneous resource ("Actual Energy Regulation Generation Impact"/"AER Generation

Impact"), and this AER shall become the Controlling AER. The Study Group shall reduce the AER Generation Impact in the earliest possible Period to the amount needed for the AER to meet the Recovery Criteria. To the extent that reservoir elevations in the Trial UNPR AER subsequently recover to the levels at which they would have been absent the Unplanned Non-power Requirement (as indicated by the Base UNPR AER for Periods with actual flows), the Study Group shall reduce the AER Generation Impact in the earliest Period hydraulically usable in the AER. The AER Generation Impact shall not exceed the Maximum Generation Impact as reduced when hydraulically usable in the AER; *provided* if a Trial UNPR AER Re-Regulation is run for a subsequent Unplanned Non-power Requirement, it might result in the amount of the Maximum Generation Impact being changed.

c. Special Provisions with Respect to Interchange Due to the Actual Energy Regulation Generation Impact

When the current Period of the AER has an AER Generation Impact remaining (at which time the net sum of Interchange imports and exports will equal the negative AER Generation Impact), the following provisions shall apply.

i. Return of Flexibility

Any Party whose FAA is positive pursuant to section 9(k), *Adjustments in Firm Energy Load Carrying Capability During Operating Year*, shall return any outstanding balance in the current Period to the extent needed to put the Coordinated System in balance and in proportion to the total Coordinated System's outstanding flexibility.

ii. Return of Interchange Energy

Requests by any Party to the other Parties for return of Interchange Energy may only be made to the extent needed to meet such Party's firm load assuming use of declared Coordinated System Firm Resources and shall be limited by such Party's Indicated Import in the deficit AER. A Party shall prorate its requests for return of Interchange Energy to the other Parties based upon outstanding balances with such Parties.

iii. Transmission Rights as Substitute for Interchange Wheeling Rights

The Parties shall treat replacement energy (energy obtained by a Party to replace Interchange Energy that such Party is unable to obtain from the other Parties due to implementation of this procedure 9(b)-4.) as if it were Interchange Energy for purposes of transmission pursuant to paragraph 14(g)(1), *Interchange Energy*.

D. Expedited Unplanned Non-power Requirements Assessment

At the request of a Requesting Party, the Study Group shall run on an accelerated basis a Base UNPR AER and a Trial UNPR AER to test and incorporate an Unplanned Non-power Requirement into the Controlling AER ("Expedited UNPR Assessment"). No changes shall be made in the Expedited UNPR Assessment regulations from the Controlling AER other than the inclusion of the Unplanned Non-power Requirement or the modification of the previously submitted non-power requirements in the Trial UNPR AER.

Procedure 9(b)-5. Actual Energy Regulation for Purposes of a Flexibility Request

This long-term procedure has the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure shall also be rescinded. This procedure shall apply only to accumulations of Flexibility Adjustments that exceed zero.

Summary: This procedure applies when a Party intends to advance FELCC pursuant to subsection 9(k), *Adjustments in Firm Energy Load Carrying Capability During Operating Year*. The Parties shall determine the impact of a Party's requested adjustment of its monthly FELCC, including return schedule, pursuant to the following procedure. In assessing impacts, the Parties shall use Conservative Streamflow Estimates and shall endeavor to minimize potential impacts to the extent possible. The requested adjustment may be made if the tests defined in subpart 9(b)-5.B.2.a. below are satisfied. If they are not, the available accumulated flexibility shall be allocated according to subarticle 9(b)-5.B.2.b.ii.(B) below.

A. Procedures for Requesting a Flexibility Adjustment

A Flexing System may submit Flexibility Adjustments for a Period whenever AER data submittals are required; *provided* any such adjustment shall only be applicable on a prospective basis from the estimated effective date of the next Controlling AER until the end of the Period (the remaining portion of the Period). The Flexing System shall indicate its desired return schedule. The Flexing System may change its Flexibility Adjustment(s) in future AERs for the same Period, but only on a prospective basis and only for the remaining portion of the Period. The Study Group shall test the submitted Flexibility Adjustment for compliance with the following limitations prior to incorporating such Flexibility Adjustment into the Controlling AER.

B. Testing Submitted Flexibility Adjustments for Compliance with Flexibility Limitations

When a Flexibility Adjustment is submitted, the Study Group shall take the following sequential steps.

1. Test for Compliance with Individual Party Limitation

The Study Group shall test the submitted Flexibility Adjustment, including the desired return schedule, and any outstanding Flexibility Adjustments of the submitting Party for compliance with the Party limitations contained in subparagraph 9(k)(1)(A), *Individual Party Limitations*, and, if necessary, limit such Flexibility Adjustment so that such submitting Party's limitations are not exceeded.

2. System Limitation

a. Test for Compliance with System Limitations

i. Coordinated System Limitation

The Study Group shall determine the amount of flexibility available pursuant to the Coordinated System limitation (six or nine percent of remaining hydroelectric FELCC) contained in subparagraph 9(k)(1)(B), *Coordinated System Limitation*, and test the submitted Flexibility Adjustment, as modified under part 9(b)-5.B.1. above, and any outstanding Flexibility Adjustments, for compliance with such limitation.

ii. Compliance with Recovery Criteria

The Study Group shall test the submitted Flexibility Adjustment, as modified under part 9(b)-5.B.1. above, and any outstanding Flexibility Adjustments, for consistency with the Recovery Criteria by running a Trial Flexibility Actual Energy Regulation ("Trial Flex AER"), and, if necessary, (i) re-regulate the Coordinated System to the extent needed to meet the Recovery Criteria, and (ii) advance returns of Coordinated System Flexibility Adjustments from the aggregate desired return schedules into the latest Period(s) possible that meets the Recovery Criteria, including the current Period. If the aggregate of the current request and outstanding Flexibility Adjustments does not meet the Recovery Criteria, the Study Group shall use the Trial Flex AER to determine the amount of flexibility in the current Subperiod that satisfies the Recovery Criteria. Such flexibility amount for the current Subperiod shall equal the aggregate of all positive FAA balances at the end of such

Subperiod plus the total load that can be accommodated in the current Subperiod while meeting the Recovery Criteria and subtracting the Coordinated System's FELCC in the current Subperiod from the Controlling AER.

b. Applying the Appropriate System Limitation

i. Modified Submitted Flexibility Adjustment(s) that Satisfy System Limitations

If the submitted Flexibility Adjustment, as modified under part 9(b)-5.B.1. above, and all outstanding Flexibility Adjustments, complies with both of the System limitations set out in part 9(b)-5.B.2. above, the Study Group shall incorporate it into the Controlling AER.

ii. Modified Flexibility Requests that Do Not Satisfy Either the Coordinated System Limitation or the Recovery Criteria

If the flexibility request, as modified under part 9(b)-5.B.1. above, and all outstanding Flexibility Adjustments, do not satisfy either the Coordinated System limitation or the Recovery Criteria, the following shall apply.

A. Determining the Amount of the "Available Accumulated Flexibility"

The Study Group shall determine the amount of "available accumulated flexibility" for the current Period which shall be the lower of the flexibility available under article 9(b)-5.B.2.a.i. or 9(b)-5.B.2.a.ii. above.

B. Allocating Available Accumulated Flexibility

The Study Group shall allocate the available accumulated flexibility among all Parties projecting to have a positive FAA balance at the end of the Period. The allocation shall be based upon the percentage share of each such Party's FELCC to the total of all such Parties' FELCC; *provided* that no Party shall be allocated less than the lower of its hydroelectric floor or five percent of its remaining FELCC. This allocation can result in a forced reduction of an FAA. The hydroelectric floor of any Party projected not to have a positive FAA balance at the end of the period shall be allocated to the other Parties; *provided* nothing shall prevent that Party from later exercising its right to its hydroelectric floor.

C. Hydroelectric Floor

A Party's hydroelectric floor shall be calculated according to the Procedure Formula 9(b)-5. below; *provided* a Party shall not be allocated more than the sum of its current request and current FAA balance.

Procedure Formula 9(b)-5.

HF = (PHF/CSHF)CSFL

Where, for each Party,

HF	=	Hydroelectric floor, in megawatts.
PHF	=	A Party's Hydroelectric FELCC, in megawatt months, for the ensuing Period through the end of the Critical Period or Operating Year, whichever ends first.
CSHF	=	The Coordinated System's Hydroelectric FELCC, in megawatt-months, for the ensuing Period through the end of the Critical Period or Operating Year, whichever ends first.
CSFL	=	The Coordinated System's available accumulated flexibility determined under subarticle 9(b)-5.B.2.b.ii.(A). above.

C. Incorporation of Flexibility Adjustments into the Actual Energy Regulation

1. Placement in the Controlling Actual Energy Regulation

The Study Group shall adjust the Parties' FELCCs as necessary to reflect the submitted Flexibility Adjustments or as necessary to reflect required adjustments to Parties' FAA balances resulting from modifications or allocations pursuant to this procedure 9(b)-5.

The Study Group shall incorporate the adjusted FELCCs into the Controlling AER on a Period basis pursuant to the foregoing provisions of this procedure 9(b)-5.

The Study Group shall include adjustments to FELCC or estimates thereof on a Period basis pursuant to procedure 9(b)-6., *Foregoing Firm Energy Load Carrying Capability to Influence Refill in the Actual Energy Regulation*.

2. Firm Energy Load Carrying Capability to be used to Determine Estimated Interchange Energy Rights

For the purposes of determining Initial AECs for the current Period that includes a Flexibility Adjustment permitted under subprocedure 9(b)-5.B. above, the Study Group shall consider a Flexing System's most recently submitted estimated FELCC, as adjusted above, for a Period to be in effect throughout such Period.

3. Firm Energy Load Carrying Capability to be used to Determine Initial AECs

For the purposes of determining Initial AECs for Periods after the current Period that includes a Flexibility Adjustment permitted under subprocedure 9(b)-5.B. above, the Study Group shall consider a Flexing System's FELCC for each Subperiod to be its adjusted FELCC integrated over that Subperiod based upon the time Flexibility Adjustments affected Interchange Energy rights and obligations.

4. Actual Energy Regulation Ending Elevations

For the purposes of determining estimated AER EEs, the Study Group shall integrate a Flexing System's estimated FELCC for each Subperiod over the time Flexibility Adjustments affected Interchange Energy rights and obligations.

Procedure 9(b)-6. Foregoing Firm Energy Load Carrying Capability to Influence Refill in the Actual Energy Regulation

This long-term procedure 9(b)-6. has the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure 9(b)-6. shall also be rescinded.

In order to increase the reservoir elevations computed in the AER, any Party may reduce its FELCC prospectively and have the Study Group reflect such reduction in the Controlling AER subject to the following conditions.

A. Non-shapeable Energy Adjustments

A Party's FELCC reductions shall not be allowed in Periods that had required adjustments under paragraph 6(h)(3), *Adjustment for Non-shapeable Energy Capability*.

B. Limitation on Reductions

The Party shall identify the amount and placement of the desired FELCC reduction(s) to the Study Group. Such reductions shall only be allowed in the remaining portion of the current Period or any subsequent Period(s) that are between the anticipated effective date of the next Controlling AER and the end of the Operating Year.

Once the above conditions are met, the Study Group shall reflect the requested reduction in a Party's FELCC in the next Controlling AER. The Study Group shall determine the net FELCC foregone in any Period by computing the day-weighted average effect that such reduction would have had on Interchange Energy rights and obligations over the Period.

Procedure 9(b)-7. Establishment of Firm Energy Load Carrying Capability Based Upon the Actual Energy Regulation

This long-term procedure 9(b)-7. shall have the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure 9(b)-7. shall also be rescinded.

The Study Group shall establish FELCC based upon the end-of-July AER EEs contained in the final Controlling AER for the immediately preceding Operating Year.

Subsection 9(d) Interchange Energy

Procedure 9(d)-1. Scheduling of Interchange Energy

This long-term procedure 9(d)-1. shall have the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure 9(b)-7. shall also be rescinded.

The Parties' Interchange Energy transactions, when needed, shall be based on estimates of each Party's Initial AEC from the Controlling AER when it becomes effective.

Procedure 9(d)-2. Delivery of Interchange Energy

This long-term procedure 9(d)-2. shall have the same term as the Agreement.

The Supplying System and Receiving System may agree to deliver or return Interchange Energy on any hours, including Peak Load Hours ("PLH"); *provided* the Receiving System agrees to pay the incremental cost of such shaping.

Procedure 9(d)-3. Return of Interchange Energy

This long-term procedure 9(d)-3. shall have the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure 9(d)-3. shall also be rescinded.

A. Settlement of Imbalances

At the end of any Refill-hold Period when the Storage Energy of the last Controlling AER's AER EEs meets or exceeds the Settlement Criterion the Parties shall settle all Interchange Energy imbalances as follows.

1. Loaned Interchange Energy

All obligations to return Loaned Interchange Energy as of July 31 of that calendar year shall terminate.

2. Regular Interchange Energy

The Receiving System shall (i) credit interim cash advances received from the Supplying System to Regular Interchange Energy imbalances, and (ii) pay the Supplying System for any imbalances remaining as of July 31 of that calendar year pursuant to paragraph 14(a)(2), *Regular Interchange Energy Imbalances.* Upon such payment, the Receiving System's obligation to return Regular Interchange Energy imbalances to the Supplying System shall terminate.

B. Refund of Interim Cash Payments

When a Receiving System returns Regular Interchange Energy, it shall notify the Supplying System whether any associated interim cash advances shall be applied against any remaining Interchange Energy imbalance or be refunded.

Subsection 9(g) Operation of Reservoirs below Adjusted Energy Content Curves and Critical Rule Curves

Procedure 9(g)-1. Operation of Reservoirs below Adjusted Energy Content Curves and Critical Rule Curves

This long-term procedure 9(g)-1. has the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure 9(g)-1. shall also be rescinded.

A. Continuous Simulation

The Study Group shall establish the AER EEs by ensuring that the AER simulates operation of all Coordinated System reservoirs, starting from the AER EEs of the previous Subperiod, to their respective Adjusted ECCs except under the following conditions.

1. Limited Reservoir Operations

A reservoir cannot be drafted to its Adjusted ECC because of (i) discharge requirements, (ii) operation for non-power requirements, or (iii) the maximum discharge capabilities defined for it in Attachment B (as modified by paragraph 9(j)(2), *Conservation of Energy*).

2. Draft Necessary to Produce Firm Energy Load Carrying Capability

Additional draft is necessary to produce the Coordinated System's FELCC in which case the AER shall be iteratively adjusted so that Coordinated System reservoirs' elevations are drafted proportionately the same distance, expressed in feet of elevation, between adjacent CRCs[1] tabulated and identified pursuant to paragraph 9(g)(3), *Proportional Draft*. Without spilling water that reasonably is expected to be used within the Critical Period or a spill required by subpart 9(b)-3.A.3.d., *Requested Spill To Reach Energy Content Curve*, the AER shall depict each reservoir as operating to its Proportional Draft Point ("PDP") to the extent allowed by (i) discharge requirements, (ii) operation for non-power requirements, or (iii) the maximum discharge capabilities defined for it in Attachment B (as modified by paragraph 9(j)(2), *Conservation of Energy*). If a reservoir's PDP cannot be reached the indicated operations of the other reservoirs and their PDPs shall be adjusted ratably as required to produce the Coordinated System's FELCC.

B. Determination of Energy Content Curve

A reservoir's ECC shall be the lower of its Adjusted ECC or its AER EE from the Controlling AER.

C. Permissible Draft Below Energy Content Curve

Except as provided in subsection 9(l), *Provisional Energy*, and part 9(g)-1.C.2. below, no Reservoir Party shall draft any of its reservoirs below its ECC except under the following conditions.

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[1] If any CRC elevations exceed the elevation of the Adjusted ECC, the elevations of all such CRCs shall be lowered to the Adjusted ECC. For purposes of this section, the Adjusted ECC and the normal bottom of the reservoir shall be added as the highest and lowest CRCs, respectively.

1. Reservoir Balancing Within A Party's System

A Reservoir Party may exchange water between (or "balance") its reservoirs if it demonstrates that (i) the water exchanged is equivalent in useable energy to the Coordinated System, and (ii) there is equal or greater probability that its reservoirs will refill after the water is exchanged.

2. Reservoir Balancing Between Parties

A Reservoir Party may draft its reservoir down to its Assured Refill Curve ("ARC") to store the resulting energy, including related head losses, in a reservoir of another Reservoir Party so long as such energy can be returned and during such storage there is no greater risk of spill. Subsection 9(i), *Storage of Energy in Reservoirs*, shall govern such storage.

If reservoir balancing drafts pursuant to part 9(g)-1.C.1. above or storage drafts pursuant to part 9(g)-1.C.2. above affect downstream Projects, the Reservoir Party and such downstream Parties shall treat such drafts as Provisional Energy drafts under subparagraphs 9(l)(1)(C), *Production of Provisional Energy/Options to Retain Energy or Produce Energy for Return*, and 9(l)(1)(D), *Adjustment to Actual Elevations*.

Subsection 9(h) Priorities on Use of Facilities for Power

Procedure 9(h)-1. Priorities on Use of Facilities for Power

This long-term procedure 9(h)-1. shall have the same term as the Agreement.

A. General Principles

The following general principles shall govern invocation of subsection 9(h), *Priorities on Use of Facilities for Power*, to defer lower-priority energy obligations.

1. Deferral

A Party invoking deferral must satisfy the deferred obligation as soon as possible by agreement with the affected Party. When possible, such satisfaction shall have the same characteristics as the deferred performance.

2. Conditions Precedent to Deferral

A Party invoking deferral must first exercise all rights under the Agreement under its control as required in this procedure 9(h)-1.

3. Uniform Capabilities

A Party's capabilities shall be assumed to be uniform over a Period.

4. Use of Firm Load Carrying Capability

A Party may use its Firm Load Carrying Capability ("FLCC") for any purpose.

B. Invoking Subsection 9(h), *Priorities on Use of Facilities for Power*, for Prescheduled Firm Energy Load Carrying Capability Transactions

A Supplying Party may defer its Firm Energy Load Carrying Capability Transaction ("FELCC Transaction") obligations under subsection 9(h), *Priorities on Use of Facilities for Power*, on a prospective basis if it anticipates that within the seven days following any request by the requesting Party pursuant to such subsection 9(h) it would be impossible for such Supplying Party to use its facilities for higher priorities identified in subsection 9(h), *Priorities on Use of Facilities for Power*. In order to defer such transactions, between the time of the Supplying Party's declaration of deferral and ultimate delivery of energy, such Supplying Party shall satisfy the following conditions.

1. Minimum Actual Capability

The Supplying Party must develop its Minimum Actual Capability ("MAC") either by exercising its rights under the Agreement, replacing such rights with power obtained from resources other than the Party's own Firm Resources, or by displacing its rights by reducing its FELCC.

2. All Rights Exercised

All rights under the Agreement that are available to the Supplying Party must be exercised (for example, the Supplying Party must call upon In Lieu Energy, PNCA storage, flexibility, draft storage above ECC, and must exercise its rights to request an emergency AER).

C. Invoking Subsection 9(h), *Priorities on Use of Facilities for Power*, on a Real-Time Basis for Firm Energy Load Carrying Capability Transactions

To the extent that rights under the Agreement may be called upon on a real-time basis, the Supplying Party may defer its same-day FELCC Transaction obligations under subsection 9(h), *Priorities on Use of Facilities for Power*, if the Supplying Party is taking the steps set forth in subprocedure 9(h)-1.B. above.

D. Invoking Subsection 9(h), *Priorities on Use of Facilities for Power*, for Prescheduled Non-Firm Energy Load Carrying Capability Transactions

A Supplying Party may defer its Non-Firm Energy Load Carrying Capability Transactions ("Non-FELCC Transaction") obligations under subsection 9(h), *Priorities on Use of Facilities for Power*, on a prospective basis if the Supplying Party anticipates that within the seven days following any request by the requesting Party pursuant to such subsection it would be impossible for such Supplying Party to use its facilities for higher priorities identified in subsection 9(h), *Priorities on Use of Facilities for Power*. In order to defer such transactions, between the time of the Supplying Party's declaration of deferral and ultimate delivery of energy such Supplying Party shall exercise recall rights for Loaned Interchange pursuant to clause 9(d)(3)(A)(ii), *Loaned Interchange Energy*, exercise all In Lieu Energy rights pursuant to subsection 9(j), *Release of Water From Storage and In Lieu Energy Deliveries*, and release water stored above ECC; *provided* such Supplying Party may first displace its non-hydroelectric Firm Resources with non-firm capability.

E. Invoking Subsection 9(h), *Priorities on Use of Facilities for Power*, for Real-Time, Same-Day Non-Firm Energy Load Carrying Capability Transactions

The Parties shall maintain established schedules for real-time, same-day Non-FELCC Transactions until subsection 9(h), *Priorities on Use of Facilities for Power,* deferrals are prescheduled under subprocedure 9(h)-1.B. above; *provided* that the Supplying Party may defer its Non-FELCC Transaction obligations if such delivery(ies) would result in the Supplying Party not developing its FLCC.

F. Transfer Energy

Transfer Energy deliveries made pursuant to procedure 9(p)-1., *Cross-Border Flows*, shall have the same priority as Provisional Energy under subparagraph 9(l)(1)(C), *Production of Provisional Energy/Options to Retain Energy or Produce Energy for Return*.

Subsection 9(i) Storage of Energy in Reservoirs

Procedure 9(i)-1. Spill Criteria

This long-term procedure 9(i)-1. shall have the same term as the Agreement.

Before a Reservoir Party spills or forces the return of stored energy, the Reservoir Party must be able to demonstrate that the related storage space is required for another use (*e.g.*, the reservoir is full, the reservoir faces a non-power requirement including flood control or a maximum elevation constraint, or storage space is necessary for operating room in an amount not to exceed the operating room the Reservoir Party would maintain for its own account).

Procedure 9(i)-2. Basing Refill Criterion on the Actual Energy Regulation

This long-term procedure 9(i)-2. shall have the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure 9(i)-2. shall also be rescinded.

The Study Group shall use the Storage Energy of the AER EEs from the Controlling AER to determine whether the Refill Criterion has been satisfied.

Procedure 9(i)-3. Basing Settlement Criterion on the Actual Energy Regulation

This long-term procedure 9(i)-3. shall have the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure 9(i)-3. shall also be rescinded.

The Study Group shall use the Storage Energy of the AER EEs from the Controlling AER to determine whether the Settlement Criterion has been satisfied.

Subsection 9(j) Release of Water From Storage and In Lieu Energy Deliveries

Procedure 9(j)-1. Date When Non-power Requirements Affect 9(j) Releases/Energy In Lieu Thereof

This long-term procedure 9(j)-1. shall have the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure 9(j)-1. shall also be rescinded.

A. Planned Non-power Requirements

Non-power Requirements submitted pursuant to section 6, *Determination of Firm Load Carrying Capability*, need not affect a regulation in order to influence the release of storage pursuant to subsection 9(j), *Release of Water From Storage and In Lieu Energy Deliveries*. When determining subsection 9(j), *Release of Water From Storage and In Lieu Energy Deliveries*, releases, the originally submitted specifications of such requirements shall be used.

B. Unplanned Non-power Requirements

An Unplanned Non-power Requirement shall influence subsection 9(j), *Release of Water From Storage and In Lieu Energy Deliveries*, releases and deliveries of energy in lieu thereof on the later of the effective date of the Controlling AER which considered the Unplanned Non-power Requirement or the start of the Unplanned Non-power Requirement.

Procedure 9(j)-2. General Methods and Procedures

This long-term procedure 9(j)-2. shall have the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure (j)-2. shall also be rescinded.

The following daily subprocedures 9(j)-2.A., 9(j)-2.B., 9(j)-2.C., and 9(j)-2.D., shall apply when the owner of a downstream Project requests the release of storage from a reservoir, except as provided in procedures 9(j)-3., *In Lieu Energy Transactions for Federal Reservoirs and Mid-Columbia Projects*, and 9(j)-4., *In Lieu Energy Transactions Between the Washington Water Power Company and Projects Downstream of Long Lake Reservoir*.

A. Release of Storage

When an owner of a downstream Project requests the release of storage from a reservoir, the Reservoir Party may either release storage subject to applicable non-power requirements or deliver energy in lieu thereof as set out in subprocedures 9(j)-2.B. and 9(j)-2.C. below. The Reservoir Party's release of such water shall satisfy its obligation to release the storage or deliver energy in lieu thereof, subject to the continuing energy obligations set out in subprocedure 9(j)-2.D. below.

B. Energy In Lieu of Storage Release

This subprocedure 9(j)-2.B. applies to all requests for release of water or In Lieu Energy, including those from any composite reservoir. For purposes of this subprocedure 9(j)-2.B., the term "downstream Party" means a downstream Project owner; *provided* for the Federal Composite Reservoir "downstream Party" shall mean an Owner or Participant, as appropriate. A Reservoir Party supplying energy to downstream Party(ies) in lieu of releasing water from a constrained Project shall not be required to supply more energy than the Pooled H/K In Lieu Limit ("PHILL"). The PHILL shall equal the greater of the amounts indicated in parts 9(j)-2.B.1. and 9(j)-2.B.2. below.

1. Downstream Parties' Energy Limited by Non-power Requirements

The total of all downstream Parties' Downstream Conversion Factors multiplied by the difference between (i) the estimated release, and (ii) the maximum release as limited by a non-power requirement.

2. Or the lesser of

The lesser of the amounts indicated in subparts 9(j)-2.B.2.a. and 9(j)-2.B.2.b. below.

a. Reservoir Party's Energy Limited By Non-power Requirements

The Reservoir Party's Downstream Conversion Factor multiplied by the difference between (i) the estimated release, and (ii) the maximum release as limited by a non-power requirement.

b. Downstream Parties' Energy Limited by Maximum Turbine Discharge

The total of all downstream Parties' Downstream Conversion Factors multiplied by the difference between (i) the estimated release, and (ii) the maximum turbine discharge as specified in the most recently updated *PNCA Plant Data Book*.

If the sum of all such energy deliveries exceeds the PHILL, each requesting downstream Party shall reduce its request so that the In Lieu Energy equivalent of its request does not exceed the difference between such Party's FELCC and its Required Actual Capability ("RAC"). The Reservoir Party shall honor such Adjusted Requests if the sum of the Adjusted Requests equals the PHILL. If not, the Reservoir Party shall make deliveries of In Lieu Energy pursuant to parts 9(j)-2.B.3. or 9(j)-2.B.4. below as appropriate.

3. Increases

If the total of the Adjusted Requests is lower than the PHILL, any remaining energy after satisfying the Adjusted Requests shall be delivered pro rata based on the requesting Parties' Downstream Conversion Factors; *provided* that no Party shall be allocated more than its original request.

4. Additional Reductions

If the total of the Adjusted Requests exceeds the PHILL, the Reservoir Party shall deliver energy to meet the Adjusted Requests to the extent there is flexibility remaining from such Party's RAC less its FELCC that is not being dedicated for other purposes with a higher priority as identified in subsection 9(h), *Priorities on Use of Facilities for Power*. Reductions of In Lieu Energy deliveries (from the Adjusted Requests) shall be allocated pro rata based on the requesting Parties' Downstream Conversion Factors.

C. In Lieu Energy Methodologies

For purposes of this subprocedure 9(j)-2.C., the term "downstream Party" means a downstream Project owner; *provided* for the Federal Composite Reservoir "downstream Party" shall mean an Owner or Participant, as appropriate.

1. Entrapment

The methodology for considering entrapment as it relates to In Lieu Energy shall be determined by the Reservoir Party and the affected downstream Project owner prior to the Operating Year and shall be adhered to during that Operating Year. Such Parties may employ different methodologies for each Project[2]; *provided* if entrapment is claimed, the delivery and return of In Lieu Energy each day shall be based on the difference between the energy production capabilities at the downstream Project computed (i) as if the water had been released from the upstream reservoir, and (ii) as if the water had not been released. The calculations shall assume that releases from the entrapping Project are limited by the smaller of its maximum turbine discharge capability or its channel discharge capacity.

2. Flow-times

The following flow-times are established:

Hungry Horse to Flathead Lake/Thompson Falls	1 Day
Flathead Lake/Thompson Falls to Noxon/Cabinet Gorge	1 Day
Noxon/Cabinet Gorge to Albeni Falls	0 Day
Albeni Falls to Box Canyon/Boundary	1 Day
Box Canyon/Boundary to Grand Coulee	1 Day
Coeur d'Alene to Long Lake	1 Day
Long Lake to Grand Coulee	0 Day
Libby to Grand Coulee	2 Days
Duncan to Grand Coulee	1 Day
Mica to Arrow	1 Day
Arrow to Grand Coulee	0 Day
Grand Coulee to Mid-Columbia Projects[3]	0 Day
Lake Chelan to Lower Columbia Projects	1 Day
Round Butte to The Dalles/Bonneville	0 Day

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[2] For example, with respect to Hungry Horse and Noxon, entrapment in Flathead Lake might be agreed to as a consideration in the delivery and return of In Lieu Energy whereas, with respect to Hungry Horse and Mid-Columbia plants, it might be agreed that entrapment in Flathead Lake would not be considered.

[3] For each upstream reservoir, flow-times to Mid-Columbia Projects shall be uniform.

3. Scheduling Elections

To determine the methodology for scheduling daily receipts and returns of In Lieu Energy, each downstream Party for each of its Projects annually shall select either subpart 9(j)-2.C.3.a. or 9(j)-2.C.3.b. below and notify the affected Reservoir Party in writing of its selection at the time the downstream Project owner makes its first In Lieu Energy schedule for the Operating Year; *provided* if a downstream Project owner fails to provide written notice, the Reservoir Party shall employ the methodology inherent in the downstream Project owner's first schedule of the Operating Year for the duration of such year. Any election shall be in effect for all In Lieu Energy supplied during that Operating Year and for returns of such energy regardless of when returned.

a. Uniform Over the Day

The Reservoir Party (in this case the Delivering Party) shall schedule In Lieu Energy deliveries to a downstream Project owner uniformly over all hours of the day at a rate not to exceed the difference between the downstream Project's (i) maximum generation as set forth in the *PNCA Plant Data Book,* and (ii) projected day's total generation divided by the number of Heavy Load Hours ("HLH"). If necessary to provide the downstream Project owner with the total amount of energy to be supplied and if requested by the downstream Project owner, the Delivering Party shall increase the schedule of energy uniformly over Light Load Hours ("LLH").

b. Uniform Over 18 Hours

In the alternative, the Reservoir Party (in this case the Delivering Party) shall schedule In Lieu Energy deliveries to a downstream Project owner uniformly over 18 hours of the day designated by the Delivering Party.

If a downstream Project owner demonstrates to the reasonable satisfaction of the affected Reservoir Party that circumstances would enable such downstream Project owner to use storage releases in an hourly shape more favorable than that provided by the alternatives in subparts 9(j)-2.C.3.a. and 9(j)-2.C.3.b. above, In Lieu Energy shall be delivered and returned in accordance with a mutually-agreed schedule reflecting those circumstances.

4. Schedule Changes Limitation

The Parties may change In Lieu Energy schedules by mutual agreement unless the equivalent water would have been released prior to such change.

5. Hydraulic Capabilities of Projects

The *PNCA Plant Data Book* for the current Operating Year shall establish the maximum hydraulic capabilities of all Projects.

6. Spill Credits

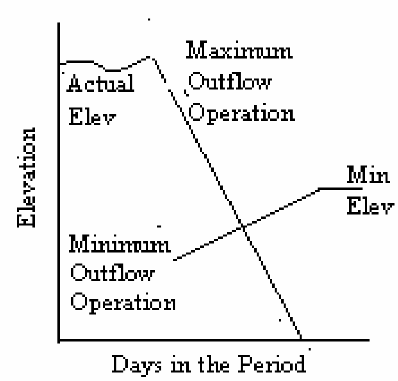
A Reservoir Party's release of Assigned Water that results in spill at a downstream Project shall reduce the obligation of such downstream Project owner to return In Lieu Energy by the energy equivalent of the difference between the Project's actual outflow and the Project's maximum hydraulic capabilities. When Assigned Water is released from more than one upstream reservoir, such reductions shall be prorated among the upstream reservoirs on the basis of the Assigned Water being released from each reservoir. In no event shall any reduction at a reservoir be greater than the energy equivalent of the Assigned Water that was released at that reservoir.

7. Miscellaneous

a. Conversion of Elevation Constraints to Outflow Constraints

The Reservoir Party shall convert its elevation constraint(s) to outflow limitations for the purpose of determining In Lieu Energy limitations. In making the conversion, the Reservoir Party shall assume an unrestricted operation at the reservoir for the longest time possible until a minimum outflow operation must commence to meet the elevation constraint (see Figure 1). The Reservoir Party shall use its own inflow assumptions and the maximum hydraulic capability set forth in the *PNCA Plant Data Book*.

Figure 1



For purposes of implementing subprocedure 9(j)-2.B., *Energy In Lieu of Storage Release*, the Reservoir Party shall use as the maximum release capability for its constrained Project the minimum outflow as used above but only for the portion of the Period indicated by such calculation. For other portions of the Period, the Reservoir Party shall not use any additional restrictions in determination of the PHILL. During that portion of the Period that the unrestricted operation is possible the Reservoir Party shall not impose any outflow limitations. In the event that the projected outflow needed to meet the elevation specified as the minimum elevation requirement is less than the outflow indicated in the Controlling AER, the Reservoir Party shall use the actual outflow as the maximum hydraulic capability of the affected Project for In Lieu purposes.

b. Daily Interpolations of ECCs

Except in the cases covered by subpart 9(j)-2.C.7.c. below, the Reservoir Party shall compute ECC elevations for each day by prorating the amount of storage draft that corresponds to the applicable ECC elevations, as specified in subprocedure 9(g)-1.B., *Determination of Energy Content Curve,* at the beginning and end of each Subperiod in a manner that results in uniform daily drafting or filling. The Reservoir Party shall compute daily reservoir elevations that correspond to the daily draft or fill which shall determine daily rights and obligations.

c. Doglegs

If the end-of-Subperiod ECC changes during a Subperiod, any previously calculated daily ECC elevations shall be in effect for each day prior to the date the Controlling AER reflecting such change becomes effective. For the remaining days of the Subperiod the Reservoir Party shall compute daily ECC elevations in accordance with the methodology set forth in subpart 9(j)-2.C.7.b. above starting from the last daily ECC elevation computed prior to the effective date of the such Controlling AER on the date of such daily ECC through the end of the Subperiod.

d. Non-power Requirements/Limitations on In Lieu Rights

When an Unplanned Non-power Requirement prevents a reservoir from being drafted to its ECC, the elevation resulting from such non-power requirement shall be treated as the ECC until the original ECC exceeds the elevation resulting from such non-power requirement. Notwithstanding any adjustment under this subpart, forced returns of In Lieu Energy shall be based upon the original ECC.

8. Scheduling Provisions

Transactions between a Reservoir Party and downstream Project owners shall be scheduled as follows.

a. Downstream Project Owners' Request

During each normal business day, each downstream Project owner shall inform the Reservoir Party of the amount of storage releases it estimates it will request, if any, for the following business day and all intervening days ("Preschedule Day(s)") by 1200 hours, and shall provide a final request by 1400 hours.

b. Reservoir Party's Response

The Reservoir Party shall inform the downstream Project owner of its intention to either release the water or offer the energy equivalent of such requested storage releases.

c. Agreement on Shape

Each downstream Project owner and the Reservoir Party shall establish (i) the total amount of In Lieu Energy to be scheduled for the Preschedule Day(s) corresponding with the Assigned Water, and (ii) the hourly shape of such schedule.

D. Return of In Lieu Energy

For purposes of this subprocedure 9(j)-2.D., the term "downstream Party" means a downstream Project owner; *provided* for the Federal Composite Reservoir "downstream Party" shall mean an Owner or Participant, as appropriate.

1. Duration of Return Obligation

The obligation to return In Lieu Energy shall continue into succeeding Operating Year(s) until fully discharged.

2. Return of In Lieu Energy After Termination

Upon a downstream Project owner's termination of its right to storage releases from a reservoir under subsection 9(j)(4), *Termination and Reinstatement*, the downstream Party may designate as a release of Assigned Water any outflow of that reservoir above any planned or Unplanned Non-power Requirement minimum flow constraints, and return the associated In Lieu Energy as provided in subpart 9(j)-2.D.2.a. and as limited by subpart 9(j)-2.D.2.b. below.

a. Reservoir Party's Ability to Accept

The Reservoir Party shall accept the return of In Lieu Energy in an amount not to exceed the energy equivalent of the actual outflow in excess of planned or Unplanned Non-power Requirement minimum outflow constraints. Such energy equivalent shall equal the amount of Assigned Water designated by the downstream Party multiplied by the greater of the Reservoir Party's Downstream Conversion Factor or the total of all affected downstream Project owners' Downstream Conversion Factors. If the Reservoir Party's Firm Resources cannot accept the return of In Lieu Energy immediately because of flow-time constraints, the downstream Party shall modify its request to accommodate the flow-time limitation.

b. Reduction of Voluntary In Lieu Energy Returns

A Reservoir Party may refuse to accept the return of In Lieu Energy in the event that the sum of all affected downstream Parties' In Lieu Energy returns exceeds the amount determined under subpart 9(j)-2.D.2.a.. above, in which case the Reservoir Party shall determine the amount of In Lieu Energy return to be accepted from each downstream Party according to the Procedure Formula 9(j)-1. below.

Procedure Formula 9(j)-1.

$ILR_{dsp} = L(R_{dcf})$

Where, for each downstream Party requesting an In Lieu Energy return,

ILR_{dsp} = The In Lieu Energy return allocated to the downstream Party (not to exceed its initial request).

L = The limit of In Lieu Energy returns that the Reservoir Party must accept determined in subpart 9(j)-2.D.2.a. above, less the total of In Lieu Energy returns of all downstream Parties whose initial request would not be limited by this formula.

R_{dcf} = The ratio of the downstream Project owner's Downstream Conversion Factor to the sum of the Downstream Conversion Factors of all downstream Parties who request In Lieu Energy returns except any Party whose initial In Lieu Energy return request was met.

Procedure 9(j)-3. In Lieu Energy Transactions for Federal Reservoirs and Mid-Columbia Projects

This long-term procedure 9(j)-3. shall have the same term as the Agreement; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, this procedure 9(j)-3. shall also be rescinded.

For purposes of this procedure 9(j)-3., the term "downstream Party" shall mean both Owners and Participants. When a downstream Party requests In Lieu Energy from a Federal Reservoir, the following subprocedures 9(j)-3.A., 9(j)-3.B., 9(j)-3.C., 9(j)-3.D., 9(j)-3.E., 9(j)-3.F., 9(j)-3.G., 9(j)-3.H., 9(j)-3.I., 9(j)-3.J., and 9(j)-3.K. shall apply instead of subprocedures 9(j)-2.A., *Release of Storage*, 9(j)-2.C., *In Lieu Energy Methodologies*, with the exception of part 9(j)-2.C.7., *Miscellaneous*, which shall still apply, and subprocedure 9(j)-2.D., *Return of In Lieu Energy*.

A. The Federal Composite Reservoir

The Federal Composite Reservoir consists of Federal Reservoirs that are treated as being located at the Grand Coulee Project, *i.e.*, there is no entrapment in or time delay between intervening reservoirs.

B. Assignment of Rights and Obligations to Owners and Participants

Both Owners and Participants may request delivery of In Lieu Energy from the Federal Reservoir pursuant to this procedure 9(j)-3. Each downstream Party shall arrange transactions of In Lieu Energy directly with the Administrator, and shall be solely responsible for any obligation(s) thereby incurred.

Except as provided in subprocedure 9(j)-3.F. below, the involved Parties shall determine the amount of water that a downstream Party has a right to request the release of or the amount of Assigned Water that is being released from the Federal Reservoirs based upon the relationship of the Federal Composite Reservoir's actual adjusted content (sum of the actual contents of the Federal Reservoirs, as adjusted for Provisional Energy drafts, entrapment, and the Canadian Storage Agreement), to the Federal Composite Reservoir's adjusted ECC content (sum of the ECC contents of all of individual Federal Reservoirs, as adjusted for Provisional Energy drafts, entrapment, and the Canadian Storage Agreement). The Administrator shall compute daily the amount of Assigned Water in each of the Federal Reservoirs for each downstream Party by allocating the amount of Assigned Water in the Federal Composite Reservoir for such Party to each Federal Reservoir having actual adjusted content above ECC pro rata on the basis of the amount by which such reservoir's actual adjusted content is above ECC.

For purposes of implementing paragraph 9(j)(7), *Settlement When the Agreement Terminates,* each downstream Party shall be responsible for the settlement of its Assigned Water balance determined through this procedure 9(j)-3.

C. Calculations

The Study Group shall use the *PNCA Plant Data Book* to calculate the Relative Maximum Discharge and Composite Factor for each downstream Party as follows.

1. Rock Island Shares

Determine the percent share of the Rock Island Project output to be divided between the Public Utility District No. 1 of Chelan County, Washington (Chelan) and Puget Sound Energy, Inc. (Puget), to be used in parts 9(j)-3.C.2. and 9(j)-3.C.3. below as follows.

a. Chelan

Calculate Chelan's share by multiplying (i) Chelan's percent ownership of units B1 through B10, and (ii) the maximum discharge of units B1 through B10 plus, (iii) the product of Chelan's ownership share of Units

U1 through U8, and (iv) the maximum discharge of Units U1 through U8. For purposes of this procedure 9(j)-3., this product divided by the maximum discharge of all units at the Rock Island Project is deemed to be Chelan's percent ownership in the Rock Island Project.

b. Puget

For purposes of this procedure 9(j)-3., Puget's share shall be deemed to be one minus the allocation share calculated in subpart 9(j)-3.C.1.a. above.

2. Project Relative Maximum Discharge

Calculate the product of (i) each Mid-Columbia Project's maximum turbine discharge less that median incremental natural streamflow between such Mid-Columbia Project and the Chief Joseph Project as calculated in part 9(j)-3.C.5. below and (ii) the downstream Party's percent allocation in such Mid-Columbia Project times the product of such Mid-Columbia Project's energy conversion factor and 24 hours per day.

3. Composite Factor

Calculate the product of (i) the downstream Party's percent allocation in each Mid-Columbia Project and (ii) such Mid-Columbia Project's energy conversion factor times 24 hours per day. This product summed up for each Mid-Columbia Project the downstream Party has a share in shall be termed the downstream Party's Composite Factor.

4. Downstream Party's Relative Maximum Discharge

Sum the following quotients determined for each Mid-Columbia Project: (i) each Mid-Columbia Project's Relative Maximum Discharge calculated in part 9(j)-3.C.2. above; and (ii) that downstream Party's Composite Factor at such Project. This product summed for each Mid-Columbia Project in which the downstream Party has a share shall be termed the downstream Party's Relative Maximum Discharge.

5. Median Incremental Streamflows

The median incremental natural streamflow for each Mid-Columbia Project in part 9(j)-3.C.2. above shall be (i) one-third of the sum of April, May, and June's median unregulated streamflow for such Mid-Columbia Project from the Historical Period of Record less (ii) one-third of the sum of April, May, and June's median unregulated streamflow for the Chief Joseph Project from the Historical Period of Record.

D. Distribution

The Composite Factors and Relative Maximum Discharges shall be distributed by the Study Group to each Party prior to the beginning of the Operating Year.

E. Use of Downstream Party's Relative Maximum Discharge

In all determinations of the incremental amount of water for a downstream Party that could, if released at Grand Coulee, be used to generate energy by such Party, or is currently being released in excess of the maximum amount that can be used for generation of energy by such Party, the actual daily discharge of the Chief Joseph Project shall be compared to such Party's Relative Maximum Discharge as determined in part 9(j)-3.C.4. above.

F. Termination of a Federal Reservoir from the Federal Composite Reservoir

A downstream Party may terminate its right to water at any Federal Reservoir in accordance with paragraph 9(j)(4), *Termination and Reinstatement*, when such Party's right at that reservoir is greater than the amount of Assigned Water allocated to that reservoir under subprocedure 9(j)-3.B.; *provided* the downstream Party shall not terminate for the purpose of increasing its right to water in the Federal Composite Reservoir, but only to reduce an anticipated obligation at the reservoir so terminated, by designating water releases. After termination, the reservoir shall no longer be included in the Federal Composite Reservoir for that downstream Party and at-site actual and minimum discharge limits shall apply. The downstream Party shall be responsible for the amount of Assigned Water allocated to such reservoir under subprocedure 9(j)-3.B.

G. Reinstatement of a Federal Reservoir to the Federal Composite Reservoir

Subject to paragraph 9(j)(4), *Termination and Reinstatement*, and any applicable methods and procedures, a downstream Party may reinstate a terminated Federal Reservoir into the Federal Composite Reservoir by promptly informing the Administrator of its decision after publication of the Controlling AER that reflected the change in the ECC of the terminated reservoir.

H. Daily Maximum Pooled Composite In Lieu Energy Delivery

The sum of all Federal Composite Reservoir In Lieu Energy deliveries made by the Administrator shall not exceed the Administrator's daily maximum pooled Composite In Lieu Energy delivery. To determine the Administrator's daily maximum pooled composite In Lieu Energy delivery, the Administrator shall add the Federal incremental generating capability of all Federal Reservoirs with water stored above ECC. Federal incremental generating capability is the difference between maximum outflow given non-power requirements and the projected outflow multiplied by such reservoir's or reservoirs' corresponding Downstream Conversion Factor.

I. Deferrals of In Lieu Energy

If flow-times through the Federal Reservoirs, channel discharge limits, or restrictions on ordering storage releases out of Treaty Storage restrict the Administrator's ability to produce the requested pooled In Lieu Energy, the Administrator shall inform the downstream Parties and may defer delivery of the restricted portion of the In Lieu Energy to coincide with the restricted generating capability. Deferrals caused by flow-time shall be scheduled using established flow-times. A requesting downstream Party may accept delivery on the delayed schedule or cancel its request for the restricted In Lieu Energy.

J. Scheduling Provisions

Transactions between the Administrator and downstream Parties shall be scheduled as follows on each normal business day for the Preschedule Day(s).

1. Chief Joseph Estimate

By 0900 hours the United States shall provide the downstream Parties with an estimate of the Chief Joseph outflow.

2. Downstream Party's Request

By 1200 hours any downstream Party intending to request Federal Composite Reservoir In Lieu Energy shall inform the Administrator of its requested Federal Composite Reservoir total outflow, with the minimum and maximum amounts of In Lieu Energy it can accept. The Administrator shall limit such requested outflow to the downstream Party's Relative Maximum Discharge as determined in part 9(j)-3.C.4. above.

3. The United States Response

By 1300 hours the United States shall inform the downstream Party of the revised Chief Joseph outflow estimate and the downstream Party's Federal Composite Reservoir In Lieu Energy schedule.

4. Downstream Parties' Schedule Modifications

If the Chief Joseph outflow estimate identified in part 9(j)-3.J.3. changes from the estimate provided in part 9(j)-3.J.1. by more than 10,000 cubic feet per second, the downstream Party may modify its request in a corresponding amount.

5. Agreement on Shape

Each downstream Party and the Administrator shall establish the total amount of In Lieu Energy to be scheduled for the Preschedule Day(s) corresponding with the Assigned Water. Unless reduced to conform with the limitations of subprocedure 9(j)-3.H. above, the Assigned Water shall equal the difference between the downstream Party's requested Federal Composite Reservoir total outflow as specified in part 9(j)-3.J.1. and as may be modified in part 9(j)-3.J.4. and in the revised Chief Joseph outflow estimate as specified in part 9(j)-3.J.3., *provided* if the resulting In Lieu Energy schedule exceeds the downstream Party's limits set in part 9(j)-3.J.2. the Assigned Water shall be appropriately adjusted so that such limits are observed. Such request for Assigned Water release shall be subject to the limitations of subprocedure 9(j)-3.H. above and may be reduced by the Administrator if necessary to comply with such subprocedure 9(j)-3.H. Such delivery shall be uniform on all hours.

K. Accounting Procedures

1. The Administrator's Accounting Responsibilities

a. Daily Accounting

Each workday the Administrator shall make available to each downstream Party information sufficient to allow that downstream Party to calculate its Federal Composite Reservoir In Lieu Energy rights and obligations.

b. Monthly Accounting

By the fourth workday of each month the Administrator shall make available to each downstream Party an accounting for each Federal Reservoir of all In Lieu Energy transactions between such downstream Party and the Administrator during the preceding month, which accounting shall include the following data in megawatt hours.

i. Gross Right

In Lieu Energy gross right.

ii. Actual Monthly Receipts

In Lieu Energy received for the month.

iii. Actual Receipts to Date

In Lieu Energy received to date.

iv. Actual Monthly Returns

In Lieu Energy returned for the month.

v. Actual Returns to Date

In Lieu Energy returned to date.

vi. Net Right

In Lieu Energy net right.

2. Participant Accounting Responsibilities

Upon request of an Owner, each Participant shall provide such Owner an accounting of the Participant's In Lieu Energy transactions relating to the Owner's Project(s).

Procedure 9(j)-4. In Lieu Energy Transactions between The Washington Water Power Company and Projects Downstream of Long Lake Reservoir

This long-term procedure 9(j)-4. shall have the same term as the Agreement.

When the owner of a downstream Project requests release of storage pursuant to subsection 9(j), *Release of Water From Storage or In Lieu Energy Deliveries*, from the Spokane Reservoirs (Coeur d'Alene and Long Lake reservoirs), the following subprocedures 9(j)-3.A., 9(j)-3.B., 9(j)-3.C., 9(j)-3.D., and 9(j)-3.E. shall apply in addition to subprocedure 9(j)-2.

A. Spokane River Composite Reservoir

The Spokane River Composite Reservoir shall have the attributes of a single reservoir located at the Long Lake Project. Washington Water Power shall apply the Coeur d'Alene reservoir channel flow restrictions when it calculates the amount of water the owner of a downstream Project has a right to request the release of from the Spokane River Composite Reservoir.

B. Determination of the Amount of Water the Owner of a Downstream Project has the Right to Request Release of from Spokane Reservoirs

Except as provided below in subprocedure 9(j)-4.E., the involved Parties shall determine the amount of water that the owner of a downstream Project has a right to request the release of or the amount of Assigned Water that is being released from the Spokane Reservoirs based upon the relationship of the Spokane Composite Reservoir's actual content (sum of the actual contents of the Spokane Reservoirs) to the Spokane Composite

Reservoir's ECC content (sum of the ECC contents of the Spokane Reservoirs). The Washington Water Power Company shall daily compute the amount of Assigned Water in each of the Spokane Reservoirs for each downstream Project owner by allocating the amount of Assigned Water in the Spokane River Composite Reservoir to each of the Spokane Reservoirs having actual content above ECC pro rata on the basis of the amount each such reservoir's actual content is above ECC.

C. Daily Maximum Pooled Composite In Lieu Energy Delivery

To determine Washington Water Power's daily maximum pooled composite In Lieu Energy delivery, Washington Water Power shall add its incremental generating capability of all Washington Water Power's reservoirs with water stored above ECC. The incremental generating capability is the difference between maximum outflow given non-power requirements and the projected outflow multiplied by its corresponding Downstream Conversion Factor.

D. Deferrals of In Lieu Energy

If flow-times through the Spokane Reservoirs or channel discharge limits restrict Washington Water Power's ability to produce the requested pooled In Lieu Energy, Washington Water Power shall inform downstream Project owners and may defer delivery of the restricted portion of the In Lieu Energy to coincide with the restricted generating capability. Deferrals caused by flow-time shall be scheduled using established flow-times. A requesting owner of a downstream Project may accept delivery on the delayed schedule or cancel its request for the restricted In Lieu Energy.

E. Termination

An owner of a downstream Project may terminate its right to water at either Spokane Reservoir under the conditions specified in paragraph 9(j)(4), *Termination and Reinstatement*, of the Agreement, but only at a time when the downstream Project owner's resulting right to a release from such reservoir would be greater than the amount of Assigned Water allocated to that reservoir at such time pursuant to subprocedure 9(j)-4.B. above; *provided* such termination shall not be exercised for the purpose of increasing the downstream Project owner's entitlement to water in the Spokane River Composite Reservoir, but only to reduce an anticipated obligation at the reservoir so terminated by designating water releases. During the time when a downstream Project owner has terminated such right to water in a Spokane Reservoir, the Spokane River Composite Reservoir shall terminate and at-site limits with respect to actual and minimum discharges shall apply. The amount of Assigned Water for such downstream Project owner in such reservoir at the time of termination shall be the amount allocated to such reservoir pursuant to subprocedure 9(j)-4.B. above at such time.

Procedures 9(j)-5. Federal Reservoir/Real-time Modifications

This procedure 9(j)-5. shall have a term of ten years from the Effective Date; *provided* if procedure 9(b)-3., *Actual Energy Regulation*, is rescinded, procedure 9(j)-5. shall also be rescinded. For purposes of this procedure 9(j)-5., the term "downstream Party" shall mean both Owners and Participants.

If, in real time, the United States revises the Chief Joseph outflow estimate by more than 10,000 cubic feet per second from the estimate upon which preschedules were based under clause 9(j)-3.J.3., *The United States Response*, the downstream Party may require one corresponding modification to its Federal Composite Reservoir In Lieu Energy schedule so long as the modified release would have met all the limitations in procedure 9(j)-3., *In Lieu Energy Transactions for Federal Reservoirs and Mid-Columbia Projects*, had it originally been requested. The downstream Party shall make such adjustment uniform over the remaining whole hours of such schedule and inform the Administrator of such adjustment. The Administrator shall make appropriate adjustments to the accounting of Assigned Water for such modification.

Subsection 9(k) Adjustment in Firm Energy Load Carrying Capability During the Operating Year

Procedure 9(k)-1. Advancement of Firm Energy Load Carrying Capability

This procedure 9(k)-1. shall have the same term as the Agreement.

A Party that intends to advance FELCC pursuant to subsection 9(k), *Adjustments to Firm Energy Load Carrying Capability*, must follow procedure 9(b)-5., *Actual Energy Regulation for Purposes of a Flexibility Request*.

Procedure 9(k)-2. Delay of Firm Energy Load Carrying Capability

This long-term procedure 9(k)-2. shall have the same term as the Agreement.

A Party may delay FELCC by (i) increasing the contents of its reservoirs over its CRC, (ii) deferring rights to storage releases under this Agreement, or (iii) making other arrangements for increasing its AEC in future Period(s) equivalent to the increase in its FELCC for such Period(s). Upon request, such Party shall demonstrate its ability to produce the claimed increase in the Coordinated System's FELCC during the remaining months of the Operating Year under the streamflows used in the LDR. A Party may not delay more FELCC in the current Period than it has in such Period. A Party's delays of FELCC shall not be incorporated into the AER.

Subsection 9(l) Provisional Energy

Procedure 9(l)-1. Provisional Energy

This long-term procedure 9(l)-1. shall have the same term as the Agreement. For purposes of this procedure 9(l)-1. the term “downstream Party” includes Owners and Participants and references to the downstream Party’s Project(s) shall mean the downstream Party’s share of such Project’s(s’) generating capability.

Except as provided in procedure 9(l)-2., *Reservoir Operating Margin*, a Reservoir Party may draft its reservoirs below the Reservoir Operating Margin, if it exists, or the end-of-Period AER EE indicated in the Controlling AER by declaring Provisional Draft and invoking the following subprocedures 9(l)-1.A., 9(l)-1.B., 9(l)-1.C., 9(l)-1.D., 9(l)-1.E., 9(l)-1.F., and 9(l)-1.G.

A. General Provisions

The Parties shall use the same travel times and conversion factors for the delivery and return of Provisional Energy as is used for In Lieu Energy; *provided* that capacities applicable to the delivery and return of Provisional Energy shall be based upon the actual capacities of units available for service at the time of such delivery or return.

B. Declaration of Provisional Draft

A Reservoir Party shall declare Provisional Draft and make a corresponding increase to its reservoir’s Reservoir Provisional Draft Account whenever it operates its reservoir below the Reservoir Operating Margin, if it exists, or the end-of-Period AER EE indicated in the Controlling AER.

C. Election and Notification Requirements of Reservoir Party

1. Choice of Accounting

A Reservoir Party declaring Provisional Draft shall inform downstream Parties of its election to base its accounting for reductions of its Reservoir Provisional Draft Account on the first or the last increment of water recovered and shall provide to the downstream Parties its estimates of the total amount and duration of Provisional Draft.

2. Notification of Duration of Provisional Draft Reductions

Before reducing its Reservoir Provisional Draft Accounts, the Reservoir Party shall advise all downstream Parties of the anticipated beginning and duration of the reduction period.

3. Notification of Provisional Draft Account Balance

The Reservoir Party shall advise other Parties daily of the balance in its Reservoir Provisional Draft Account through the notification given on the In Lieu Energy account.

D. Ability of Downstream Party to Retain Provisional Energy

A downstream Party may retain the Provisional Energy produced at its Project(s), pursuant to part 9(l)-1.D.2. below, up to the amount of its Firm Backup Energy and shall increase its Provisional Energy Retained Account by the amount of Provisional Energy retained. Upon request of any Party, a downstream Party maintaining a balance in its Provisional Energy Retained Account shall advise other Parties of the source and amounts of Firm Backup Energy equivalent to its Provisional Energy Retained Account. Upon notification of Provisional Draft, a downstream Party shall elect either part 9(l)-1.D.1. or 9(l)-1.D.2. below. For the purposes of parts 9(l)-1.D.1. and 9(l)-1.D.2. below the water equivalent of any energy referred to is based on the downstream Party's water to energy conversion factors using the actual capacities of units available for service at the time of such generation.

1. Fixed Percentage

a. Deliveries from Downstream Parties

The downstream Party shall inform the Reservoir Party of the percentage of increased generation produced by the Provisional Draft at the downstream Party's Project(s) that the downstream Party elects to return to the Reservoir Party; *provided* the downstream Party may not change its election for the duration of such Provisional Draft operation. The downstream Party shall return the Provisional Energy pursuant to the Procedure Formula 9(l)-1. below in the shape elected under subprocedure 9(l)-1.E. below. The Reservoir Party and the downstream Party shall increase the downstream Party's Provisional Return Account by the water equivalent of the Provisional Energy returned. The downstream Party shall increase its Provisional Energy Retained Account by the amount of Provisional Energy retained.

b. Deliveries from Reservoir Party

When the Reservoir Party reduces its Reservoir Provisional Draft Account the Reservoir Party shall deliver energy to the downstream Party according to the Procedure Formula 9(l)-1. below. The Reservoir Party and the downstream Party shall reduce the downstream Party's Provisional Return Account by the water equivalent of the energy delivered.

2. Daily Retain or Return

a. Deliveries from Downstream Parties

The downstream Party shall inform the Reservoir Party of its election to retain or return on a daily basis all incremental generation produced by the Provisional Draft at the downstream Party's Project(s) according to the Procedure Formula 9(l)-1. below. The Reservoir Party and the downstream Party shall increase the downstream Party's Provisional Return Account by the water equivalent of the energy returned. The downstream Party shall increase its Provisional Energy Retained Account by the amount of Provisional Energy retained.

b. Deliveries from Reservoir Party

When the Reservoir Party reduces its Reservoir Provisional Draft Account, the Reservoir Party may on a daily basis determine whether on the next Prescheduled Day(s) to deliver the generation that would have occurred at the downstream Project(s) until the day when deliveries must be made on all remaining days in order to get the total energy back ("forced return"). The Reservoir Party shall deliver energy to the downstream Party according to the Procedure Formula 9(l)-1. below based on its expected reductions to the Reservoir Provisional Draft Account. The Reservoir Party and the downstream Party shall decrease the downstream Party's Provisional Return Account by the water equivalent of the energy delivered.

3. Energy Deliveries for Provisional Draft on a Daily Basis

Procedure Formula 9(l)-1.

$PET = 24(P_{(1,\,2,\,\text{or}\,3)}(\Delta PD)(H/K_{DP}))$

Where for each Prescheduled Day,

PET	=	Provisional Energy Transaction ("PET"). Average energy, in megawatt hours, for the Prescheduled Day(s) to be delivered by the downstream Party (if positive) or delivered by the Reservoir Party (if negative).
P_1	=	Percentage of generation the downstream Party elects to return under part 9(l)-1.D.1. above (the same percentage shall be used for the downstream Party and Reservoir Party).
P_2	=	Percentage of generation the downstream Party on a daily basis elects to return under subpart 9(l)-1.D.2.a. above (either zero or 100 percent).
P_3	=	Percentage of generation the Reservoir Party elects to deliver on a daily basis under subpart 9(l)-1.D.2.b. above (either zero or 100 percent, but subject to the limitations set forth in such subsection).
ΔPD	=	Change in the Reservoir Provisional Draft Account.
H/K_{DP}	=	Downstream Project's estimated daily energy conversion factor for Prescheduled Day(s) at the time of the transaction in accordance with subprocedure 9(l)-1.A. above.

E. Provisional Energy Shaping Provisions

Before a downstream Party's first return of Provisional Energy to a Reservoir Party in each Operating Year, the downstream Party shall notify the Reservoir Party of its choice of part 9(l)-1.E.1. or 9(l)-1.E.2. below. Except as provided in part 9(l)-1.E.3. below, the downstream Party's selection shall apply to PETs between the downstream Party and that Reservoir Party during such Operating Year; *provided* such election shall not affect any PET obligations carried forward from a prior Operating Year. A downstream Party's failure to provide an election shall bind such Party to the method inherent in its first PET schedule.

1. Uniform Delivery

The Supplying System shall deliver the PET to the Receiving System uniformly on all hours of each Prescheduled Day, *provided* deliveries from the Reservoir Party to the downstream Party on HLHs shall be at a rate limited to the difference between (i) the downstream Party's projected maximum capability at its affected downstream Project(s) and (ii) the downstream Party's projected HLH generation from such Project(s) divided by the number of HLHs. If necessary to provide the downstream Party with the total amount of PET to be supplied and if requested by the downstream Party, the Delivering System shall increase the schedule of PET uniformly over LLHs; or

2. Six-Hour Window

For each Prescheduled Day, the Delivering System may designate up to six hours during which PETs cannot be delivered and shall deliver such PET uniformly during the remaining hours.

3. Exception to Shaping Provisions

If a downstream Party demonstrates to the reasonable satisfaction of the Reservoir Party that special circumstances allow such downstream Party to achieve generation shaped more favorably using upstream storage releases than in part 9(l)-1.E.1. or 9(l)-1.E.2. above, the PET shall be delivered and returned in accordance with a mutually-agreed manner that accommodates the special circumstances.

F. Reduction of Reservoir Provisional Draft Accounts

For the purposes of parts 9(l)-1.F.1. and 9(l)-1.F.2. below the "daily ECC" means the daily interpolated values of the ECC for a reservoir as defined in subprocedure 9(g)-1.B., *Determination Of Energy Content Curve*, and computed under subparts 9(j)-2.C.7.b., *Daily Interpolations of ECCs,* and 9(j)-2.C.7.c., *Doglegs.* Each Reservoir Party shall reduce its Reservoir Provisional Draft Account in accordance with its declaration under part 9(l)-1.C.1. above as follows.

1. First Increment of Water

If a Reservoir Party declared that the first increment of water reduces the Reservoir Provisional Draft Account, as the actual elevation of the reservoir and the corresponding daily ECC for such reservoir converge, the Reservoir Party shall reduce the Reservoir Provisional Draft Accounts proportionately.

2. Last Increment of Water

If a Reservoir Party declared that the last increment of water reduces the Reservoir Provisional Draft Account, the Reservoir Party shall reduce the Reservoir Provisional Draft Account proportionately at the earliest of the following times.

a. When Reaching Upper Boundaries

After the reservoir's adjusted elevation reaches within one foot of the highest permissible elevation during the Period, the Reservoir Party shall reduce its Reservoir Provisional Draft Account for such reservoir at a rate sufficient to keep the Reservoir's adjusted elevation at such highest permissible elevation.

b. When Reaching Lower Boundaries

After the reservoir's actual (unadjusted) elevation reaches within one foot of the lowest permissible elevation during the Period, the Reservoir Party shall reduce its Reservoir Provisional Draft Account for such reservoir by the lesser of 10,000 cubic feet per second or at the rate of convergence between the actual (unadjusted) elevation and the daily ECC.

c. When the Coordinated System Refills

When the Coordinated System meets its Refill Criteria between January 1 and the end of the Refill-hold Period and to the extent that the Reservoir Party is required to maintain in its reservoir any water put into provisional space, the Reservoir Party shall reduce its Reservoir Provisional Draft Account at the lesser of 10,000 cubic feet per second or the rate at which the reservoir fills into the provisional space.

G. Inadvertent Provisional Draft

If a Reservoir Party fails to make a Provisional Draft declaration and any of its Projects are inadvertently below end-of-Period ECC at the end of the Period, the Reservoir Party shall make a retroactive Provisional Draft declaration and all downstream Parties shall be treated as if they had made a election to retain the Provisional Energy pursuant to subprocedure 9(l)-1.D. above; *provided* (i) the downstream Parties shall not be required to provide Firm Backup Energy pursuant to subparagraph 9(l)(1)(B), *Required Conditions*, (ii) the Reservoir Party shall reduce its Provisional Energy accounts by the last increment of water released pursuant to part 9(l)-1.C.1. above, and (iii) with respect to the inadvertent Provisional Draft, the affected reservoir(s) shall be considered to be at its ECC for purposes of the return of In Lieu Energy under paragraph 9(j)(3), *In Lieu Energy Return*.

Procedure 9(l)-2. Reservoir Operating Margin

This long-term procedure 9(l)-2. shall have the same term as the Agreement; *provided* that any Party may reopen this procedure 9(l)-2. at any time for the purpose of making this procedure 9(l)-2. less administratively cumbersome. For purposes of this procedure 9(l)-2., the term "downstream Party" includes Owners and Participants and references to the downstream Party's Project(s) shall mean the downstream Party's share of such Project(s) generating capability.

A. Computations

So long as a Reservoir Party reasonably determines that its reservoir will return to the ECC by the end of a Period, the Reservoir Party may operate such reservoir within its Reservoir Operating Margin without having to declare Provisional Draft. When the elevation of a reservoir is descending within the Reservoir Operating Margin, any downstream Parties electing to participate in Reservoir Operating Margin Exchanges shall deliver to such Reservoir Party the increased generation resulting from operation at their Project(s), and when the elevation of a reservoir is ascending within the Reservoir Operating Margin, the Reservoir Party shall deliver to returning downstream Parties such corresponding generation. All such deliveries shall be Reservoir Operating Margin Exchanges. Neither Party shall charge the other for the delivery of energy under this procedure 9(l)-2.

1. Designation of Flow-times

At the beginning of each Operating Year, each Reservoir Party shall designate those of its reservoirs that, for purposes of this procedure 9(l)-2., have zero flow-time. If no designation is made, the Parties shall use In Lieu Energy flow-times established pursuant to part 9(j)-2.C.2., *Flow-times*.

2. Designation of Participation in Reservoir Operating Margin Exchanges

Each affected downstream Party may participate in Reservoir Operating Margin Exchanges at any upstream reservoir. Within ten business days of receipt of a Reservoir Party's designation of flow-times, any affected downstream Party wishing to participate in such exchanges shall notify the Reservoir Party of its election respecting each reservoir for that Operating Year. If no election is made, the downstream Party shall not participate in any exchange of energy under this procedure 9(l)-2. during such Operating Year.

3. Computation of Reservoir Operating Margin

The Reservoir Party shall compute a Reservoir Operating Margin for each of its reservoirs. The Reservoir Operating Margin shall equal the greater of (i) the storage equivalent of five feet of reservoir draft below the Controlling AER's AER EE for the current Period, or (ii) the storage equivalent of the reservoir's discharge at its maximum turbine capability for twelve hours.

4. Computation of Reservoir Operating Margin Draft

The Reservoir Party shall compute the Reservoir Operating Margin Draft for each of its reservoirs or its composite reservoir if available. The Reservoir Operating Margin Draft for individual reservoirs shall equal the lesser of (i) the content of the Controlling AER's AER EE for such reservoir minus the reservoir's actual content, and (ii) the Reservoir Operating Margin. The Reservoir Operating Margin Draft for any composite reservoir shall be the lesser of (i) the content of the Controlling AER's AER EE minus the actual content summed for all reservoirs within such composite reservoir (including any reservoir(s) withdrawn from the composite reservoir for In Lieu Energy purposes), and (ii) the Reservoir Operating Margin at Grand Coulee for the Federal Composite Reservoir or the Reservoir Operating Margin at Coeur d'Alene Lake for the Spokane River Composite Reservoir.

B. Reservoir Operating Margin Exchange

When a Reservoir Party intends to operate its reservoir within the Reservoir Operating Margin it shall notify the participating Parties of the amount of anticipated Reservoir Operating Margin Draft. If the Reservoir Operating Margin Draft is positive, the Reservoir Party shall calculate the Reservoir Operating Margin Exchange according to the Procedure Formula 9(l)-2. below. A downstream Party shall schedule Reservoir Operating Margin Exchanges using the flow-times designated pursuant to part 9(l)-2.A.1. above and according to the Procedure Formula 9(l)-2. below.

Procedure Formula 9(l)-2.

$\text{ROME} = \Delta\text{ROMD}\ (H/K_{DP})$

Where, for each Prescheduled Day(s),

ROME = Reservoir Operating Margin Exchange: hourly rate, in megawatts, for the Prescheduled Day to be delivered by the downstream Party (if positive) or delivered by the Reservoir Party (if negative).

ΔROMD = The daily thousand of second foot days' change in the Reservoir Operating Margin Draft for the Prescheduled Day.

H/K_{DP} = Downstream Project's estimated daily energy conversion factor, in megawatts per thousands of second foot days, for Prescheduled Day(s) at the time of the transaction in accordance with subprocedure 9(l)-1.A., *General Provisions*.

Subsection 9(p) Cross-Border Flows

Procedure 9(p)-1. Cross-Border Flows

This long-term procedure 9(p)-1. shall have the same term as the Agreement. For purposes of this procedure 9(p)-1. the term "downstream Party" shall include Owners and Participants.

A. Communication and Negotiation of Impacts of Other-than-Treaty-Storage Agreement

A Party contemplating an Other-than-Treaty-Storage Agreement ("OTSA") shall to the extent practicable consult with all potentially affected downstream Parties. Immediately after negotiating such an agreement, the Initiating Party shall notify all affected downstream Parties whereupon the Initiating Party and affected downstream Parties shall negotiate how to treat the resulting impacts. If a resolution is not reached within 15 business days, the following provisions shall be implemented for those downstream Parties who did not reach agreement with the Initiating Party.

B. Default Provisions

1. Quantity of Other-than-Treaty Storage

The quantity of Other-than-Treaty Storage potentially affected by an OTSA shall be the amount identified in the OTSA. If the OTSA does not specify the amount of affected Other-than-Treaty Storage, the Initiating Party and all potentially affected Parties shall establish the quantity of Other-than-Treaty Storage potentially affected within 15 business days from the time this default procedure 9(p)-1. becomes effective.

2. Election

a. Initial Election

Within 30 calendar days of receiving notification of an OTSA, a downstream Party shall make an Initial Election to retain or to return all of the Flow Deviation Generation Difference relating to that OTSA and may control the disposition of such Flow Deviation Generation Difference.

b. Subsequent Elections

At least 30 days before each Operating Year a downstream Party may change its Initial Election or any Subsequent Downstream Party's Election for future Operating Years. Such downstream Party shall specify the number of consecutive whole Operating Years in the Election Period, and shall communicate its Election to the Initiating Party and to the Project owner(s) of the Project(s) in which the downstream Party has a participating share. Upon making any Subsequent Downstream Party's Election, the electing downstream Party and the Initiating Party shall divide the Flow Deviation Generation Difference according to the Procedure Formula 9(p)-1. below.

i. Division of Control

The downstream Party shall calculate the percentage of Flow Deviation Generation Difference between 40 percent and 100 percent over which it has control, with the percentage increasing as the Election Period increases according to the Procedure Formula 9(p)-1. below.

Procedure Formula 9(p)-1.

C = (((.6)(L - 1)/(T - 1)) + (.4))(100)

Where,

C	=	The percentage of Flow Deviation Generation Difference that the downstream Party may designate to be retained or returned.
L	=	The length of the Election Period in whole consecutive Operating Years.
T	=	The remaining term of this Agreement in whole Operating Years.

The Initiating Party shall notify the downstream Party whether it must retain or return the remainder (100 percent - C) of the Flow Deviation Generation Difference, and the downstream Party shall notify the Initiating Party and the applicable Project owner(s) of the results of its calculations.

ii. Subsequent Downstream Party and Initiating Party Elections

At least ten business days before the Operating Year the downstream Party and the Initiating Party shall each elect whether the downstream Party will retain or return their respective shares of the Flow Deviation Generation Difference for the Election Period.

3. Calculation of Daily Flow Deviations

The sum of all Flow Deviations for a day (using BC Hydro's reported operating statistics) shall equal the difference between the combined Treaty outflow of Mica, Arrow, and Duncan from the combined actual outflow of Mica, Arrow, and Duncan.

4. Flow Deviation Generation Difference

The affected downstream Project owners shall compute a daily Flow Deviation Generation Difference for each downstream Party by multiplying the Composite Factors by the difference between (i) the lesser of the flow that occurred at the downstream Project from the combined actual outflow of Mica, Arrow, and Duncan Projects resulting from the OTSA or the downstream Project's hydraulic capability and (ii) the lesser of the flow that would have occurred at the downstream Project from the Treaty outflow of the Mica, Arrow, and Duncan Projects or the downstream Project's hydraulic capability; *provided* Project hydraulic capability shall be adjusted for unit outages on a daily average basis. Project owners shall verify and communicate the foregoing calculations with Initiating and Returning Parties.

5. Exchanges of Transfer Energy

The Initiating Party and Returning Parties shall exchange Transfer Energy daily in conformance with their individual Elections without charge except for incidental transmission charges pursuant to subsection 14(g), *Transmission Service Charges*. The Initiating Party and each Returning Party shall establish schedules for the delivery of Transfer Energy which quantities shall be computed according to the Procedure Formula 9(p)-2. below.

Procedure Formula 9(p)-2.

TE = FDGD(IP+RP)

Where for each Returning Party,

TE	=	The Transfer Energy to be delivered by the Initiating Party to the Returning Party if negative (*i.e.*, the generation at the Project is less than it would have been absent the OTSA Flow Deviation) or delivered by the Returning Party to the Initiating Party if positive (*i.e.*, the generation at the Project is greater than it would have been absent the OTSA Flow Deviation).
FDGD	=	The Returning Party's daily Flow Deviation Generation Difference.
IP	=	The percent of the daily Flow Deviation Generation Difference to be returned as specified by the Initiating Party pursuant to article 9(p)-1.B.2.b.i., *Division of Control,* (either zero percent or (100 percent - C) as calculated in the Procedure Formula 9(p)-1.).
RP	=	The percent of the daily Flow Deviation Generation Difference to be returned as specified by the Returning Party pursuant to article 9(p)-1.B.2.b.i., *Division of Control,* (either zero percent or C as calculated in the Procedure Formula 9(p)-1).

6. General Provisions

a. Flow-time/Entrapment

The Project owner shall not consider flow-time or entrapment when calculating Flow Deviation Generation Difference or when scheduling the delivery of Transfer Energy.

b. Scheduling Procedures

i. Shape of Transfer Energy

The Initiating Party or the Returning Party shall deliver Transfer Energy uniformly over all hours (equal hourly amounts); *provided* the Delivering Party may choose not to deliver over PLHs.

ii. Preschedules

An Initiating Party shall notify affected downstream Parties and the Project owners of any Flow Deviation(s) during the preceding day(s) for which notification has not been provided. The Initiating Party shall use its best efforts to notify the Returning Parties and Project owners by 1000 hours of the amount of the Flow Deviation. By 1100 hours the Project owners and Returning Party shall establish preschedules based on such Flow Deviation information.

c. Application to Signatories of the Current Non-Treaty Storage Agreement

So long as the Non-Treaty Storage Agreement, BPA Contract Number DE-MS79-91BP92785, or its successor is in place, this procedure 9(p)-1. shall not govern signatories' activities under such agreement, but this procedure 9(p)-1. shall govern activities between a signatory and a non-signatory. If an OTSA exists when a signatory becomes a non-signatory the non-signatory must participate fully in this procedure 9(p)-1. and must make an Initial Election.

7. New Initial Election

a. Change in Quantity of Other-than-Treaty Storage

If the quantity of Other-than-Treaty Storage related to an OTSA increases, each downstream Party shall make a new Initial Election on the incremental quantity of such storage. For the purposes of determining which increment of Other-than-Treaty Storage is being used the Parties shall assume that such storage identified above is the last to be stored and first to be released.

b. New or Modified Non-Treaty Storage Agreement

When the United States Entity or the Administrator enters into a new Non-Treaty Storage Agreement with the Canadian Entity or BC Hydro that replaces the Agreement Between Bonneville Power Administration and British Columbia Hydro and Power Authority, Contract No. DE-MS79-90BP92754, or when the existing agreement is modified significantly, a downstream Party may make a Secondary Election respecting the affected Other-than-Treaty Storage.

c. Changing Interests Among Participants

A Participant's Election shall bind the Participant's entire participating interest throughout the Election Period notwithstanding changes in the percentage of the Participant's participating interest; *provided* a new Participant which becomes a Party to the Agreement may make an Initial Election during its predecessor's declared Election Period.

8. Inclusion of Planned Flow Deviations in Section 6, *Determination of Firm Load Carrying Capability*, Planning

Subject to the approval of the United States Entity, an Initiating Party may include operations under an OTSA in its section 6, *Determination of Firm Load Carrying Capability*, planning. The Parties shall negotiate how to incorporate such operations in planning and how to treat the impacts of such inclusion; *provided* unless otherwise agreed operations under an OTSA shall not be placed into section 6, *Determination of Firm Load Carrying Capability*, planning in a manner that reduces the treatment afforded to downstream Parties under this procedure 9(p)-1.

9. Re-negotiation

If any new Projects, dams, or facilities that influence the Columbia River flow in Canada are constructed after the Effective Date, the Parties shall re-negotiate how to address the effects created thereby.

Section 10 Transmission Lines and Associated Facilities

There shall be no long-term methods or procedures relating to this section.

Section 11 Reactive

There shall be no long-term methods or procedures relating to this section.

Section 12 Loads in Excess of Capabilities

There are currently no long-term methods or procedures relating to this section.

Section 13 Payment for Coordinated Storage Releases from Reservoirs Located in the United States

There shall be no long-term methods or procedures relating to this section.

Section 14 Other Charges

There are currently no long-term methods or procedures relating to this section.

Section 15 Non-power Uses

There shall be no long-term methods or procedures relating to this section.

Section 16 Regulatory and Judicial Authorities

There shall be no long-term methods or procedures relating to this section.

Section 17 Integration

There shall be no long-term methods or procedures relating to this section.

Section 18 Entire Agreement

There shall be no long-term methods or procedures relating to this section.

Section 19 Miscellaneous Provisions

There shall be no long-term methods or procedures relating to this section.

Section 20 Preservation of Water Rights

There shall be no long-term methods or procedures relating to this section.

Section 21 Uncontrollable Forces

There shall be no long-term methods or procedures relating to this section.

Section 22 Provisions Relating to Treaty Storage

Procedure 22(e)-1. Deviations in Use of Treaty Storage

This long-term procedure 22(e)-1. shall have the same term as the Agreement. Energy exchanges under subprocedures 22(e)-1.B. and 22(e)-1.C.below are not referenced in subsection 9(h), *Priorities on Use of Facilities for Power,* and therefore, unless otherwise agreed by the Coordinating Group, may not be deferred. For purposes of this procedure 22(e)-1. the term "downstream Party" shall include Owners and Participants.

This procedure 22(e)-1. shall only apply if (i) the United States Entity agrees to a deviation in Treaty Storage operations from the Treaty Storage operations agreed upon in the Finally Agreed Operating Plan ("Treaty deviation") and either (ii) any of the downstream Parties can neither get a release of such storage nor obtain In Lieu Energy (from Treaty Storage or the Federal Composite Reservoir), or (iii) any of the downstream Parties is not entitled to request the release of such storage or obtain In Lieu Energy due to the inclusion of the Treaty deviation in the Controlling AER. The affected Parties shall negotiate how to treat one half[4] of the effects resulting from such deviation on a case-by-case basis. In the event that the affected Parties cannot agree how to handle the effects of such deviation, each downstream Party shall elect one of the following options under subprocedure 22(e)-1.A., 22(e)-1.B., or 22(e)-1.C. below. Unless agreement is reached on how to treat later Treaty deviations, the election of the downstream Party shall bind it for purposes of all subsequent Treaty deviations that Operating Year.

A. Option A/No Action

The downstream Party accepts the generation effect of the Treaty deviation and is responsible for covering such generation effect.

B. Option B/Energy Exchanges

1. Delivery of Energy

On each day the downstream Party may require the Administrator to transfer energy to it in an amount equal to the lesser of (i) the product of the downstream Party's Composite Factor and one-half of the Preschedule Day's(s') incremental Treaty deviation (expressed in megawatt hours), or (ii) the summation of the product(s) of the downstream Party's percent allocation in each Mid-Columbia Project and such Project's Project Energy Allocation delivery for such Preschedule Day(s) as determined pursuant to Section 5, *Delivery and Scheduling of Project Energy Allocation*, of the Canadian Entitlement Allocation Extension Agreements.

2. Return of Energy

A downstream Party shall elect either subpart 22(e)-1.B.2.a. or 22(e)-1.B.2.b. below at the time of the Administrator's first delivery of energy under part 22(e)-1.B.1. to determine under what conditions such energy shall be returned.

a. First Increment

The downstream Party shall begin to return such energy when the first increment of restricted Treaty Storage is released. On each day that the incremental Treaty deviation is negative, the downstream Party shall

[4] Only one half of the power benefits resulting from the improved streamflows from Treaty Storage are owed to Canada under the terms of the Treaty.

return to the Administrator energy in an amount equal to the lesser of (i) the product of the downstream Party's Composite Factor and one-half of such day's incremental Treaty deviation (expressed in megawatt hours), or (ii) the summation of the product(s) of the downstream Party's percent allocation in each Mid-Columbia Project and such Project's Project Energy Allocation delivery as determined pursuant to Section 5, *Delivery and Scheduling of Project Energy Allocation*, of the Canadian Entitlement Allocation Extension Agreements.

b. By The End of The Operating Year

The downstream Party shall begin to return such energy when the first increment of restricted Treaty Storage is released, as specified in subpart 22(e)-1.B.2.a.; *provided* the downstream Party shall complete the return of such energy by the end of the Operating Year in which the energy was delivered by returning the energy before the restricted Treaty Storage is projected by the United States to be released. The downstream Party shall return any energy that otherwise would have been returned under subpart 22(e)-1.B.2.a. after the Operating Year, uniformly during all Heavy Load Hours of the last three months of such Operating Year unless the downstream Party's total energy return obligation is 50 percent or less of the amount of energy calculated in article 22(e)-1.B.2.a.(ii). above for each day in the last two months of such Operating Year in which case the return shall be made uniformly during the Heavy Load Hours ("HLH") of the last two months of the Operating Year; *provided* the rate of return shall be no less than one megawatt per HLH. If a delivery of one megawatt over two months exceeds the energy return obligation then the return shall be delayed until a one megawatt per HLH rate through the end of the Operating Year satisfies the return obligation.

3. Shape of Energy Exchanges

The delivery of energy under part 22(e)-1.B.1. and the return of energy under subpart 22(e)-1.B.2.a. is to be provided uniformly on all HLHs.

C. Option C/Energy Exchanges with True-Up

1. Delivery of Energy

On each day the downstream Party may require the Administrator to transfer energy to it in an amount equal to the lesser of (i) the product of the downstream Party's Composite Factor and one-half of the Preschedule Day's(s') incremental Treaty deviation (expressed in megawatt hours), or (ii) the summation of the product(s) of the downstream Party's percent allocation in each Mid-Columbia Project and such Project's Project Energy Allocation delivery for such Preschedule Day(s) as determined pursuant to Section 5, *Delivery and Scheduling of Project Energy Allocation*, of the Canadian Entitlement Allocation Extension Agreements.

2. Return of Energy

A downstream Party shall elect either subpart 22(e)-1.C.2.a. or 22(e)-1.C.2.b. at the time of the Administrator's first delivery of energy under part 22(e)-1.C.1. to determine under what conditions such energy shall be returned.

a. First Increment

The downstream Party shall begin to return such energy when the first increment of restricted Treaty Storage is released. On each day that the incremental Treaty deviation is negative, the downstream Party shall return to the Administrator energy in an amount equal to the lesser of (i) the product of the downstream Party's Composite Factor and one-half of such day's incremental Treaty deviation (expressed in megawatt hours), or (ii) the summation of the product(s) of the downstream Party's percent allocation in each Mid-Columbia Project and such Project's Project Energy Allocation delivery as determined pursuant to Section 5, *Delivery and Scheduling of Project Energy Allocation*, of the Canadian Entitlement Allocation Extension Agreements.

b. By The End of The Operating Year

The downstream Party shall begin to return such energy when the first increment of restricted Treaty Storage is released, as specified in subpart 22(e)-1.C.2.a.; *provided* the downstream Party shall complete the return of such energy by the end of the Operating Year in which the energy was delivered by returning the energy before the restricted Treaty Storage is projected by the United States to be released. The downstream Party shall return any energy that otherwise would have been returned under subpart 22(e)-1.C.2.a. after the Operating Year, uniformly during all HLHs of the last three months of such Operating Year unless the downstream Party's total energy return obligation is 50 percent or less of the amount of energy calculated in article 22(e)-1.C.2.a.(ii) above for each day in the last two months of such Operating Year in which case the return shall be made uniformly during the HLHs of the last two months of the Operating Year; *provided* the rate of return shall be no less than one megawatt per HLH. If a delivery of one megawatt over two months exceeds the energy return obligation then the return shall be delayed until a one megawatt per HLH rate through the end of the Operating Year satisfies the return obligation.

3. Shape of Energy Exchanges

The delivery of energy under part 22(e)-1.C.1. and the return of energy under subpart 22(e)-1.C.2.a. is to be provided uniformly on all HLHs.

4. Determination of Unavailable Entitlement

At the end of the Drawdown Period, the electing downstream Party and the Administrator shall determine whether such Treaty deviation(s) restricted the downstream Party's access to Treaty Storage. The involved Parties shall make such determination by adding (i) Canadian Storage In Lieu Energy actually received by the downstream Party that Operating Year, (ii) rights (expressed in megawatt hours) to Canadian Storage In Lieu Energy that could have been exercised and actually received[5] by the downstream Party during that Operating Year, (iii) energy exchanges received by the downstream Party pursuant to part 22(e)-1.C.2 above, and (iv) energy exchanges available under part 22(e)-1.C.2 above but not accepted by the downstream Party. The involved Parties shall convert this sum to a water equivalent by dividing the megawatt-hour total by the downstream Party's Composite Factor. The unavailable portion of the downstream Party's Treaty Storage is then determined by subtracting such water equivalent from the water equivalent of Canadian Storage above ECC at the end of the Drawdown Period.

5. Offset Against Return Obligation

The involved Parties shall convert the unavailable portion of the downstream Party's Treaty Storage of the Federal Composite Reservoir to a quantity of energy using a storage to energy conversion factor to be determined by such Parties, that approximates the decrease in the downstream Project's Canadian Entitlement return obligation as if the deviation had been included in the calculation of the Canadian Entitlement. The product of this quantity of energy and the downstream Party's percent allocation in each Mid-Columbia Project shall be offset against any exchange energy that the downstream Party has not returned by the end of the Drawdown Period to the Administrator under part 22(e)-1.C.2. above.

6. Provisional Energy Transactions

If the Treaty Storage is Provisionally Drafted at a cost[6] to the Administrator, the downstream Party shall elect one of the following.

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[5] This is intended to capture the fact that even if the regulations show that a downstream party has an entitlement, some things (reservoir balancing, etc.) might restrict what that party actually receives. The restricted amount would not be part of the calculation.

[6] In determining whether there is a cost to Bonneville, the parties would consider whether there had been a prior adjustment of the downstream party's Canadian payment obligation as well as whether there was an outright payment by Bonneville.

a. Participate

The downstream Party shall participate in the Provisional Draft by paying to the Administrator a proportionate share of the cost as mutually agreed upon by such downstream Party and the United States, or

b. Not Participate

The downstream Party shall return all related Provisional Energy to the Administrator.

Section 23 Provisions Relating to Federal Reclamation Project Requirements

There shall be no long-term methods or procedures relating to this section.

Section 24 Re-negotiation

There shall be no long-term methods or procedures relating to this section.

Section 25 Notices

There are currently no long-term methods or procedures relating to this section.

Section 26 Additional Parties

There shall be no long-term methods or procedures relating to this section.

Section 27 Kerr Project

There shall be no long-term methods or procedures relating to this section.

Exhibit C

Annual Methods and Procedures

Table of Contents

Introduction

The Parties have agreed to these methods and procedures pursuant to section 5, *Implementation of Agreement*. This exhibit includes annual methods and procedures whose specific term is one year. Annual methods and procedures may be used to implement or revise sections 6, *Determination of Firm Load Carrying Capability*, 7, *Determination of Base and Variable Energy Content Curves*, 8, *Maintenance and Reserves*, and 9, *Operating Procedures, Obligations, and Rights*, and to implement any of the other sections of this Agreement.

References in this exhibit to the Agreement include mention of sections, subsections, paragraphs, subparagraphs, clauses, and subclauses, set off by parentheses.

The methods and procedures follow the order of the Agreement. Cross-references to methods include mention of methods, submethods, parts, subparts, articles, and subarticles, set off by periods. Cross-references to procedures include mention of procedures, subprocedures, parts, subparts, articles, and subarticles, set off by periods.

Section 2 Definitions

Annual Procedure 2-1. Definitions

In this Exhibit the Parties shall use the definitions contained in both the Agreement and the long-term methods and procedures.

Section 9. Operating Procedures, Obligations, and Rights

Subsection 9(b). Actual Energy Capability

Annual Procedure 9(b)-1. Timelines for Required Data

Parties shall supply required data to the Study Group in accordance with the attached schedule. Each Reservoir Party shall submit Variable Energy Content Curves ("VECC") and underlying data for each of its reservoirs as appropriate. Each Project owner shall submit Conservative Streamflow Estimates for the current and future Periods and actual observed streamflows for the previous Period. The Study Group shall prepare the final Controlling Actual Energy Regulation ("Controlling AER") when it runs the first Actual Energy Regulation after each Period.

A. Late-Month Actual Energy Regulation

To facilitate the timely release of a Controlling AER, the Study Group shall prepare and publish the Controlling AER at least three days prior to the end of each month. At least six business days prior to the next Period, each Party shall submit to the Study Group estimated Flexibility Adjustments and any desired Firm Energy Load Carrying Capability ("FELCC") reductions for current and future Periods, and each Project owner shall submit the following data:

1. Natural Streamflows

Conservative Streamflow Estimates.

2. Variable Energy Content Curves and Flood Control Curves

Estimated VECCs and variable flood control curves for the current and future Subperiods. If a basin forecast is not available, the VECCs and variable flood control curves shall be based on the streamflows reflected in the Load Determination Re-regulation ("LDR").

B. Early-Month Actual Energy Regulation

Within the first eleven days of each month the Study Group shall prepare a Controlling AER. Each Party shall submit to the Study Group actual FELCC for the preceding Period and estimated Flexibility Adjustments and any desired FELCC reductions for the current and future Periods. Each Project owner shall submit the following data within the first eight days of a month: *provided* unless specified otherwise in the AER calendar, if the seventh day falls on a non-business day such data shall be submitted on the closest business day.

1. Natural Streamflows

Actual streamflows for the previous Subperiod and Conservative Streamflow Estimates. If the previous Subperiod is the last Subperiod of a month and if the estimate for the first Subperiod of the month was inaccurate, all adjustments to correct such inaccuracy shall be made only to the previous Subperiod.

2. Variable Energy Content Curves

Actual VECCs for the current Subperiod and estimated VECCs for future Subperiods and variable flood control curves for the current and future Subperiods. If a basin forecast is not available, the VECCs and variable flood control curves shall be based on the streamflows reflected in the LDR.

C. Unscheduled Actual Energy Regulations

Any Party that demonstrates that conditions have or are expected to change materially may require the Study Group to update the Controlling AER. Except as provided below in 3(d), the Study Group shall not be required to run the Controlling AER more than once each calendar week. Upon the Study Group's notice to the Parties that the Controlling AER will be updated, the Parties shall revise their VECCs, variable flood control curves, and FELCC, as needed, and shall update their Conservative Streamflow Estimates by incorporating actual conditions to date and shall supply such information to the Study Group by 1600 hours of the second business day after receipt of such notice.

D. Estimated Data

If a Party fails to supply estimated data within the established schedule, the Study Group shall use the latest prior estimate of such data or, if not available, the appropriate data from the LDR for the current Operating Year. The submitting Party may provide such data in a format usable by the Study Group.

E. AER Calendar for the 1997-98 Operating Year

The AER calendar for 1997-98 is on the following three pages.

F. Emergency Actual Energy Regulation

A Party making a Flexibility Adjustment may require the Study Group to run an emergency AER pursuant to this procedure if such Flexibility Adjustment meets the requirements of subsection 9(k), *Adjustments in Firm Energy Load Carrying Capability During Contract Year,* and long-term procedure 9(b)-5., *AER for Purposes of a Flexibility Request*. The Study Group shall prepare on an accelerated basis a new Controlling AER in accordance with the following guidelines; *provided* the Study Group shall not prepare an emergency AER more than once in any 48-hour period.

1. Notification to the Parties

The Study Group shall notify each Party of a request for an emergency AER. Each Party may include in the emergency AER an adjustment to its FELCC for the current Period in accordance with the requirements of subsection 9(k), *Adjustments in Firm Energy Load Carrying Capability During Contract Year*. Each Party adjusting its FELCC shall supply the Study Group with all necessary data within four working hours following such notification. For the purpose of this paragraph, "working hour" means any hour between 0700 hours and 1600 hours of any business day.

2. Running of the AER

The Study Group shall revise the Controlling AER using long-term procedure 9(b)-5., *AER for Purposes of a Flexibility Request,* on an accelerated basis.

3. Communication of AER Results

If the request for the emergency AER was received before 0830 hours the Study Group shall use its best efforts to complete the study and communicate the AER results to the Parties within the same business day. If the request was received thereafter, the study results shall be communicated no later than the next business day.

Subsection 9(j). Release of Water from Storage and In Lieu Energy Deliveries

Annual Procedure 9(j)-1. Return Rate Limitation of 20,000 cubic feet per second

Except for voluntary returns after termination, an Owner or Participant shall return to the Administrator In Lieu Energy under paragraph 9(j)(3), *In Lieu Energy Return*, at a rate no greater than the equivalent of 20,000 cubic feet per second. If the Assigned Water release exceeds

20,000 cubic feet per second, the Owner or Participant shall deliver the corresponding energy at a rate equivalent to 20,000 cubic feet per second until the return obligation is satisfied.

Subsection 9(l). Provisional Energy

Annual Procedure 9(l)-1. When Reaching Special Limitations

For the purposes of this procedure the "daily ECC" means the daily interpolated values of the Energy Content Curve for a reservoir as defined in long-term subprocedure 9(g)-1.B., *Determination Of Energy Content Curve,* and computed under long-term subparts 9(j)-2.C.7.b., *Daily Interpolations of ECCs,* and 9(j)-2.C.7.c., *Doglegs.* For the purposes of this procedure the "limiting elevation" means the lowest elevation that a reservoir can be provisionally drafted to and is determined by the Reservoir Party in the same manner as VECCs are determined pursuant to paragraph 7(d)(4), *Refill Regulations*, of the Agreement, except that (i) different confidence levels are used for each month instead of the usual 95 percent confidence level, (ii) the calculated limiting elevation is not constrained by a lower limit elevation except those resulting from Project limitations, and (iii) the Reservoir Party shall use the final Volume Forecast and hedges for each month. The confidence levels to be used for the limiting elevations are: 75 percent for January, 80 percent for February, 85 percent for March, and 95 percent for April.

Between January 1 and April 30, when the volume (thousands of second-feet days) difference between the daily ECC and the daily interpolated limiting elevation for a Federal reservoir, is less than such reservoir's outstanding Reservoir Provisional Draft Account, the Administrator shall reduce the Reservoir Provisional Draft Account so that it equals the greater of the volume difference of (i) the daily ECC and the unadjusted actual elevation of the reservoir, or (ii) the daily ECC and the daily interpolated limiting elevation of the reservoir; *provided* for the 1997-98 Operating Year such reduction to the Reservoir Provisional Draft Account shall not exceed the rate of 10,000 cubic feet per second.

Attachment 1

This Attachment will include the modeling Procedures agreed upon by the Coordinating Group in the annual methods and procedures porcess, pursuant to subparagraph 5(a)(1)(E), *Annual Methods and Procedures.*

EXHIBIT D
COORDINATED SYSTEM'S FIRM RESOURCES AS OF JUNE 18, 1997
HYDRO PROJECTS

Project	Location River	Type [1]	Normal Full El.- Ft.	Normal Bottom El.- Ft.	Useable Storage Capacity KSFD	Peak Cap. Full Res. MW	Minimum Discharge CFS [2]	Remarks
THE MONTANA POWER COMPANY								
Kerr	Flathead	1	2893.0	2883.0	614.700	180.0		
Thompson Falls	Clark Fork	2	2396.0	2380.0		85.2		
PACIFICORP								
Swift #1	Lewis	1	1000.0	878.0	225.400	268.0	0	[3]
Yale	Lewis	1	490.0	430.0	95.600	133.0	0	
Merwin	Lewis	1	239.6	209.3	57.800	150.0	Variable	
East Side	Klamath	4				3.0		
West Side	Klamath	4				0.8		
John C. Boyle	Klamath	2				82.0		
Copco #1	Klamath	2				25.5		
Copco #2	Klamath	4				29.5		
Iron Gate	Klamath	2				19.5		
Fall Creek	Fall Creek	5				2.2		
Upp. Klamath Lake	---	1	4143.3	4137.0	233.300	4.1	Variable	
Prospect #1	Rogue	5				4.7		
Prospect #2	Rogue	3				36.0		
Prospect #3	So. Fk. Rogue	5				6.8		
Prospect #4	Rogue	5				1.0		
Eagle Point	So.Fk.Big Butte Cr.	5				3.0		
Lemolo #1	No. Umpqua	1	4148.5	4097.0	6.370	28.0		
Lemolo #2	No. Umpqua	2				35.0		
Clearwater #1	Clearwater	3				12.0		
Clearwater #2	Clearwater	3				26.0		
Toketee Falls	No. Umpqua	2				42.0		
Fish Creek	Fish Creek	3				12.0		
Slide Creek	No. Umpqua	4				17.0		
Soda Springs	No. Umpqua	2				11.5		
Minor Hydro	Oregon & Washington	5				19.0		Minor Hydro includes Albany, Bend, Naches Drop, Powerdale, Naches, Stayton, Cline Falls, Wallowa Falls, Big Fork.

(1) Type:
1 Seasonal Storage Project
2 Pondage Project Downstream from Seasonal Storage
3 Pondage Project
4 Run-of-river Project Downstream from Seasonal Storage
5 Run-of-river Project

(2) Cyclic Reservoirs

(3) Effective September 1, 1983: 74% of output to PacifiCorp
26% of output to Cowlitz Co. PUD

COORDINATED SYSTEM'S FIRM RESOURCES AS OF JUNE 18, 1997
HYDRO PROJECTS

Project	Location River	Type [1]	Normal Full El.- Ft.	Normal Bottom El.- Ft.	Useable Storage Capacity KSFD	Peak Cap. Full Res. MW	Minimum Discharge CFS [2]	Remarks
PORTLAND GENERAL ELECTRIC								
Round Butte	Deschutes	1	1945.0	1860.0	138.3	300.0		3,000 cfs (3,500 cfs March
Pelton	Deschutes	2	1580.0	1573.0		108.0		through June) minimum disc-
Timothy Lake	Oak Grove Fork	1	3190.0	3125.0	31.1		10	charge below Pelton, or
Oak Grove	Oak Grove Fork	2	1990.0	1958.0		49.5		Round Butte inflow,
North Fork	Clackamas	2	665.0	646.0		54.0		whichever is less.
Faraday	Clackamas	4				43.0		
River Mill	Clackamas	2	388.8	381.0		23.0		
Bull Run	Sandy	3	655.0	648.0		22.0		
T. W. Sullivan	Willamette	4				15.0		
PUGET SOUND ENERGY, INC.								
Upper Baker	Baker	1	724.0	655.0	111.2	103.2		
Lower Baker	Baker	1	438.6	355.0	71.8	71.4		
White River	White	1	543.0	515.0	23.5	63.8		
Snoqualmie Falls	Snoqualmie	3				44.0		
Nooksack	Nooksack	3				1.7		
Electron	Puyallup	3				26.4		
THE WASHINGTON WATER POWER COMPANY								
Post Falls	Spokane	1	2128.0	2120.5	112.500	18.0		
Upper Falls	Spokane	2	1870.5	1867.0		10.2		
Monroe St.	Spokane	4	1806.0	1806.0		15.0		
Nine Mile	Spokane	2	1606.6	1590.0		26.8		
Long Lake	Spokane	1	1536.0	1512.0	52.600	72.5		
Little Falls	Spokane	2	1362.0	1351.0		36.0		
Noxon	Clark Fork	1	2331.0	2295.0	116.300	554.0		
Cabinet Gorge	Clark Fork	2	2175.0	2160.0		236.0		
Meyers Falls	Colvillle	5	1520.6	1512.0		1.3		
Priest Lake Stor.	Priest Lake, ID	1	3.0*	0.0*	35.500			

(1) Type: 1 Seasonal Storage Project
2 Pondage Project Downstream from Seasonal Storage
3 Pondage Project
4 Run-of-river Project Downstream from Seasonal Storage
5 Run-of-river Project

(2) Cyclic Reservoirs

* Gage heights

COORDINATED SYSTEM'S FIRM RESOURCES AS OF JUNE 18, 1997
HYDRO PROJECTS

Project	Location River	Type [1]	Normal Full El.- Ft.	Normal Bottom El.- Ft.	Useable Storage Capacity KSFD	Peak Cap. Full Resv. MW	Minimum Discharge CFS [2]	Remarks
PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY								
Chelan[3]	Chelan Falls	1	1100.0	1079.0	341.500	53.8		Pre-encroached
Rocky Reach[4]	Columbia	2	707.0	703.0		1270.5		
Rock Island[4]	Columbia	4	613.0	609.0		591.4		Pre-encroached
PUBLIC UTILITY DISTRICT NO. 2 OF GRANT COUNTY								
Priest Rapids[4]	Columbia	2	488.0	481.5		912.0		
Wanapum[4]	Columbia	2	571.5	560.0		986.0		
PUBLIC UTILITY DISTRICT NO. 1 OF DOUGLAS COUNTY								
Wells[4]	Columbia	2	781.0	771.0		840.0		
PUBLIC UTILITY DISTRICT NO. 1 OF PEND OREILLE								
Box Canyon	Pend Oreille	2	2031.3	2012.5		73.8		3 Hr. peaking capability 77.2 MW under lowest flows & before Boundary encroachment
Calispel Creek	Near Dalkena	5	2425.0	2404.6		0.6		
Sullivan Lake	Nr. Metaline Falls	1	2588.7	2564.0	15.40	-		

(1) & (2) See Footnotes on any other Sheet of Exhibit 1.

(3) License Restrictions: Each year from April 1 to August 15, or the date the surface elevation reaches 1096.0 feet, whichever occurs earlier, the Project total discharge may not exceed a cumulative average of 1,000 Cfs. If elevation 1096.0 feet is not reached by August 15, the discharge is limited to an amount which will not cause a draft below elevation 1092.0 feet by September 15. There are no further license restrictions after September 15.

(4) Project outputs after encroachment presently allocated to other Systems on a percentage basis, as follows:

Participant	Wanapum	Priest Rapids	Wells*	Rocky Reach	Rock Island** Units 1-10	Rock Island** Units 11-18
Eugene Water & Electric Board	2.30	1.70				
PacifiCorp	18.70	13.90	7.20	5.30		
Portland General Electric Company	18.70	13.90	21.10	12.00		
Puget Sound Energy	10.80	8.00	32.30	38.90	57.1	100.00
The Washington Water Power Company	8.20	6.10	3.70	2.90		
Seattle City Light		8.00				
Tacoma City Light		8.00				
Colockum Transmission Company, Inc.				23.00		
PUD of Grant County	36.50	36.50				
PUD of Chelan County				15.13	42.9	
PUD of Cowlitz County	2.70	2.00				
PUD of Kittitas County		.40				
PUD of Douglas County			27.70	2.77		
PUD of Okanogan County			8.00			
City of Forest Grove	0.70	0.50				
City of McMinnville	0.70	0.50				
City of Milton-Freewater	0.70	0.50				
	100.00	100.00	100.00	100.00	100.00	100.00

* Effective September 1, 1996. ** Effective July 1, 1996.

COORDINATED SYSTEM'S FIRM RESOURCES AS OF JUNE 18, 1997
HYDRO PROJECTS

Project	Location River	Type [1]	Normal Full El.- Ft.	Normal Bottom El.- Ft.	Useable Storage Capacity KSFD	Peak Cap. Full Resv. MW	Minimum Discharge CFS [2]	Remarks
CITY OF SEATTLE								
Ross	Skagit	1	1602.5	1475.0	530.546	450.0		Amount required to maintain
Diablo	Skagit	2	1205.0	1195.0		171.6		1000 cfs average discharge
Gorge	Skagit	2	875.0	869.0		182.5		at Gorge.
Newhalem	Newhalem Creek	5				2.0		
Cedar Falls	Cedar	5				30.0		
Boundary	Pend Oreille	2	1990.0	1970.0		855.0		(3)
EUGENE WATER AND ELECTRIC BOARD								
Leaburg	McKenzie	4				13.0		
Walterville	McKenzie	4				9.5		
Carmen	McKenzie	3	2605.0	2578.0		49.1		
Trail Bridge	McKenzie	5	2092.0	2080.0		3.8		
Stone Creek	Oak Grove Fork	4				11.5		(4)

(1) Type:
- 1 Seasonal Storage Project
- 2 Pondage Project Downstream from Seasonal Storage
- 3 Pondage Project
- 4 Run-of-river Project Downstream from Seasonal Storage
- 5 Run-of-river Project

(2) Cyclic Reservoirs

(3) Higher peaks can be obtained with flows over 33,000 cfs.

(4) Portland General Electric receives 15% of peak.

COORDINATED SYSTEM'S FIRM RESOURCES AS OF JUNE 18, 1997
HYDRO PROJECTS

Project	Location River	Type [1]	Normal Full El.- Ft.	Normal Bottom El.- Ft.	Useable Storage Capacity KSFD	Peak Cap. Full Resv. MW	Minimum Discharge CFS [2]	Remarks
FEDERAL COLUMBIA RIVER POWER SYSTEM								
Hungry Horse	S. Fk. Flathead	1	3560.0	3336.0	1548.500	428.0	145	
Albeni Falls	Pend Oreille	1	2062.5	2049.7	582.400	49.0	4000	
Mica [3]	Columbia	1	2475.0	2400.65	3529.200		3000	
Duncan [3]	Duncan	1	1892.0	1794.2	705.800		100	
Arrow [3]	Columbia	1	1444.0	1377.9	3579.600		5000	
Libby	Kootenai	1	2459.0	2287.0	2487.300	600.0	3000	
Grand Coulee	Columbia	1	1290.0	1208.0	2614.600	6494.0	30000	
Chief Joseph	Columbia	2	956.0	930.0		2614.0		
McNary	Columbia	2	340.0	335.0		1127.0		
John Day	Columbia	1	268.0	257.0	269.700	2484.0		
The Dalles	Columbia	2	160.0	155.0		2074.0		
Bonneville	Columbia	2	77.0	70.0		1147.0		
Dworshak	No. Fork Clearwater	1	1600.0	1445.0	1016.000	460.0	2000	
Ice Harbor	Snake	2	440.0	437.0		693.0		
Lower Monumental	Snake	2	540.0	537.0		932.0		
Little Goose	Snake	2	638.0	633.0		932.0		
Lower Granite	Snake	2	738.0	733.0		932.0		
Hills Creek	M.Fk. Willamette	1	1541.0	1414.0	122.700	34.5	100-100	Willamette basin minimum
Lookout Point	M.Fk. Willamette	1	926.0	819.0	169.600	138.0	1000-1200	outflows vary seasonally.
Dexter	M.Fk. Willamette	2				17.0		The first figure applies
Cougar	S.Fk. Willamette	1	1690.0	1516.0	77.400	28.8	200-300	to July-Nov., the second Detroit
N. Santiam	1	1563.5	1425.0	161.900	115.0	750-1000	figure to Feb.-June.	
Big Cliff	N. Santiam	2				21.0		Minimum out-flow during
Green Peter	M. Santiam	1	1010.0	887.0	157.600	92.0	300-500	December and January is
Foster	S. Santiam	1	637.0	613.0	12.500	23.0	400-800	inflow.
Lost Creek	Rogue	1	1872.0	1751.0	158.813	56.4	700	
Roza	Yakima	4				12.9		Storage operated
Chandler	Yakima	4				13.0		primarily for irrigation.
Cowlitz Falls	Cowlitz	5				70.0		

(1) Type:
1 Seasonal Storage Project
2 Pondage Project Downstream from Seasonal Storage
3 Pondage Project
4 Run-of-river Project Downstream from Seasonal Storage
5 Run-of-river Project

(2) Cyclic Reservoirs

(3) Canadian Projects

COORDINATED SYSTEM'S FIRM RESOURCES AS OF JUNE 18, 1997
HYDRO PROJECTS

Project	Location River	Type [1]	Normal Full El.- Ft.	Normal Bottom El.- Ft.	Useable Storage Capacity KSFD	Peak Cap. Full Res. MW	Minimum Discharge CFS [2]	Remarks
UNITED STATES COLUMBIA RIVER SYSTEM (Cont.)								
Anderson Ranch	S. Fk. Boise	1	4196.0	4039.6	213.300	40.0		[3]
Black Canyon	Payette	2	2497.5	2496.5		10.0		[3]
Boise River Diversion	Boise	4				2.3		[3]
Minidoka	Snake	2	4245.0	4236.0		15.6		[3]
Palisades	Snake	1	5620.0	5497.0	605.000	176.6	1,000	
PUBLIC UTILITY DISTRICT NO. 1 OF COWLITZ COUNTY								
Swift #2	Lewis	4				77.0	0	[4]

(1) Type:
1 Seasonal Storage Project
2 Pondage Project Downstream from Seasonal Storage
3 Pondage Project
4 Run-of-river Project Downstream from Seasonal Storage
5 Run-of-river Project

(2) Cyclic Reservoirs

(3) Storage operated primarily for irrigation

(4) 26% of output to Cowlitz County PUD
74% of output to PacifiCorp

Coordinated System's Firm Resources as of June 18, 1997
Thermal and Miscellaneous Firm Resources

(This list of thermal and miscellaneous Firm Resources is provided for illustrative purposes only as the Parties have discretion under the definition of Firm Resources to change these. This Exhibit will be updated after the Parties submit their thermal and miscellaneous Firm Resources after the Effective Date.)

Plant or Source	Location	Type	Peak Capacity MW
MONTANA POWER COMPANY			
Corette	Billings, MT	Steam	160.0
Colstrip 1 (50% Ownership)	Colstrip, MT	Steam	159.0
Colstrip 2 (50% Ownership)	Colstrip, MT	Steam	160.0
Colstrip 3 (30% Ownership)	Colstrip, MT	Steam	218.0
Colstrip 4 (30% Ownership)	Colstrip, MT	Steam	216.0
PACIFICORP			
Wyoming Division	Wyoming	Transfer	Variable
Centralia [1]	Centralia	Steam	1343.0
Colstrip 3 (10% Ownership)	Colstrip, MT	Steam	70.0
Colstrip 4 (10% Ownership)	Colstrip, MT	Steam	70.0
Hermiston	Hermiston	Gas	470.0
Miscellaneous Resources			
U.S.B.R. Green Springs		Contract	18.3
James River		Contract	50.0

(1) Project Operated By PacifiCorp As Agent For The Following Joint Owners:

PacifiCorp	- 47.5%
Portland General Electric Co.	- 2.5%
Puget Sound Energy, Inc.	- 7.0%
The Washington Water Power Co.	- 15.0%
City of Seattle	- 8.0%
City of Tacoma	- 8.0%
Public Utility District #1 of Snohomish	- 8.0%
Public Utility District #1 of Grays Harbor	- 4.0%
	100.0%

Grays Harbor's and Snohomish's shares of Centralia are not Firm Resources of the Coordinated System.

COORDINATED SYSTEM'S FIRM RESOURCES AS OF JUNE 18, 1997
THERMAL AND MISCELLANEOUS FIRM RESOURCES

Plant or Source	Location	Type	Peak Capacity MW
PORTLAND GENERAL ELECTRIC COMPANY			
Beaver	Clatskanie	Gas Turbine	536.0
Bethel	Salem	Gas Turbine	116.0
Summit	Govt. Camp	Diesel	6.0
Boardman (1)	Boardman, OR	Steam	530.0
Colstrip 3 (20% Ownership)	Colstrip, MT	Steam	140.0
Colstrip 4 (20% Ownership)	Colstrip, MT	Steam	140.0
Coyote Springs	Boardman, OR	Gas Turbine	230.0
Miscellaneous Resources			
Lake Oswego Corp.		Contract	0.5

(1) Project operated by Portland General as agent for the following joint owners:

Portland General Electric Company(2)	- 65.0%
Pacific Northwest Generating Company	- 10.0%
Idaho Power Company	- 10.0%
General Electric Credit Corp.	- 15.0%
	100.0%

(2) Portland General Electric's share of Boardman is the only output that is a Firm Resource of the Coordinated System.

Coordinated System's Firm Resources as of June 18, 1997
Thermal and Miscellaneous Firm Resources

Plant or Source	Location	Type	Peak Capacity MW
PUGET SOUND ENERGY, INC.			
Colstrip 1 & 2 (50% Ownership)	Colstrip, MT	Steam	330.0
Colstrip 3 (25% Ownership)	Colstrip, MT	Steam	175.0
Colstrip 4 (25% Ownership)	Colstrip, MT	Steam	175.0
Spokane MSW	Spokane, WA	Waste	23.0
Sumas Energy Cogen.	Sumas, WA	Cogen.	123.0
March Pt. 1	Anacortes, WA	Cogen.	80.0
March Pt. 2	Anacortes, WA	Cogen.	60.0
Encogen	Bellingham, WA	Cogen.	160.0
Tenaska	Ferndale, WA	Cogen.	245.0
Whitehorn #1	Ferndale, WA	Gas Turbine	67.5
Whitehorn #2 & #3	Ferndale, WA	Gas Turbine	178.0
South Whidbey Island	Langley, WA	Gas Turbine	28.5
Crystal Mountain Enumclaw, WA	Diesel	2.8	
Fredrickson #1 & #2	Spanaway, WA	Gas Turbine	178.0
Fredonia #1 & #2 Mt. Vernon, WA	Gas Turbine	247.5	
THE WASHINGTON WATER POWER COMPANY			
Northeast	City of Spokane	Combustion Turbine	69.0
Kettle Falls	Kettle Falls, WA	Steam (wood waste)	48.0
Colstrip 3 (15% Ownership)	Colstrip, MT	Steam	108.0
Colstrip 4 (15% Ownership)	Colstrip, MT	Steam	108.0
Rathdrum CT	Rathdrum, ID	Gas Turbine	176.0
Miscellaneous Resources			
Miscellaneous Small Hydro	City of Spokane	Hydro	3.0
City of Spokane Upriver	City of Spokane	Hydro	13.0
WPI	Plummer, ID	Cogen.	5.0
Potlach	Lewiston, ID	Cogen.	59.0

COORDINATED SYSTEM'S FIRM RESOURCES AS OF JUNE 18, 1997
THERMAL AND MISCELLANEOUS FIRM RESOURCES

Plant or Source	Location	Type	Peak Capacity MW
UNITED STATES COLUMBIA RIVER SYSTEM			
Thermal Resources			
WNP-2	Richland, WA	Contract (Nuclear)	1162.0
Miscellaneous Resources			
Packwood	Packwood, WA	Contract (Hydro)	28.0
Idaho Falls	Idaho Falls, ID	Contract (Hydro)	27.0
Gem State	Idaho Falls, ID	Contract (Hydro)	22.0
Wauna	Wauna, OR	Contract (CT)	36.0
CARES Columbia Wind #1	Columbia Hills, WA	Contract (Wind)	25.0
CT(WNP3 Exch. w/WWP)		Contract	0.0
CT(WNP3 Exch. w/PGE)		Contract	0.0
CT(WNP3 Exch. w/PSE)		Contract	0.0
SCE Option Energy		Contract	350.0
SDG&E Option Energy		Contract	0.0
Supplemental - SCE		Contract	0.0
Exchange Energy - SCE		Contract	0.0
Exchange Energy - A&R		Contract	0.0
Exchange Energy - SDG&E		Contract	0.0
Exchange Storage - SCE		Contract	100.0
Exchange Storage - Vernon		Contract	80.0
Exchange Energy - PASA		Contract	0.0
Exchange Energy - ABC		Contract	7.0
Deferred Return - SDG&E		Contract	0.0
Purchase - Basin		Contract	96.0
Purchase - Enron		Contract	69.0

Exhibit E

Limits of Rights to Restoration as of June 18, 1997

PROJECT	RESTORATION LIMIT MEGAWATTS Coordinated System Critical Period 24 Months or less[1]	 more than 24 months[2]
United States of America		
Albeni Falls	2	0
Big Cliff	1	1
Chandler	3	2
Cougar	3	0
Detroit	1	0
Dexter	2	1
Foster	0	3
Green Peter	5	2
Hills Creek	1	0
Hungry Horse	103	29
Lookout Point	2	1
Chelan County PUD		
Chelan	10	11
Cowlitz County PUD		
Swift #2	5	4
Eugene, City of		
Leaburg	0	1
Pend Oreille County PUD		
Box Canyon	12	11
Sullivan Lake	2	1
Seattle, City of		
Skagit River	18	33

PROJECT	RESTORATION LIMIT MEGAWATTS Coordinated System Critical Period 24 Months or less[1]	 more than 24 months[2]
Montana Power Company		
(Columbia Basin)		
Kerr	50	6
Thompson Falls	6	0
Pacific Power & Light Company		
Merwin	11	10
Swift #1	7	10
Yale	9	11
Klamath River	10	2
Portland General Electric Company		
Oak Grove	10	0
Pelton	2	0
Sullivan	2	0
Puget Sound Power & Light		
Baker River	2	5
Washington Water Power Company		
Cabinet Gorge	19	11
Lewiston	1	1
Spokane River	4	0
Noxon Rapids	22	6

Any project or group of projects not listed on this Exhibit E at the date of Execution of this Agreement shall have a restoration limit of zero.

[1] Limits apply whenever the Critical Period of the Coordinated System including Canadian Storage is 24 consecutive months or less.

[2] Limits apply whenever the Critical Period of the Coordinated System including Canadian Storage is more then 24 consecutive months.

Exhibit F

Reserves

1. Probability Mathematics

(a) Capacity Loss Probabilities

(1) The capacity loss probability distribution will be determined considering all possible combinations of simultaneous generating unit Forced Outages. An example of such determination follows:

(A) System has two generating plants with a total of five units:

Plant	Unit	MW	Outage Rate
A	1	1	0.01
A	2	2	0.01
B	1	1	0.01
B	2	3	0.01
B	3	5	0.01

(B) For each possible outage magnitude, or state, all possible combinations are considered that will result in exactly such state. For example, the combinations of outages that will result in a loss of three megawatts for this System are the following:

(i) A1, A2 out; B1, B2, B3 not out
(ii) A2, B1 out; A1, B2, B3 not out
(iii) B2 out; A1, A2, B1, B3 not out

(C) The probability of any combination existing, such as shown in 1(a)(1)(B)(i) above, is the product of the probabilities of the various single events making up such combination. For 1(a)(1)(B)(i) above, then the probability is:

$$\Pr[A1,A2 \text{ out}; B1,B2,B3 \text{ not out}] = (0.01)^2(0.99)^3$$

(D) The probability of any state existing, or exactly such amount of capacity loss, is the sum of the probabilities of all the various combinations resulting in such state. Thus, for a capacity loss of three megawatts the probability is:

$$\Pr[3 \text{ mw}] = (0.01)^2(0.99)^3 + (0.01)^2(0.99)^3 + (0.01)(0.99)^4$$

(E) If all units are the same size and have the same outage rate, this procedure reduces to the binomial formula:

$$\Pr[\text{r-fold outage}] = (n! / r!(n-r)!)p^r(1.0 - p)^{n-r}$$

where,

n = number of units
r = number of units within such group on simultaneous Forced Outage
p = Forced Outage rate of the units

(F) The cumulative capacity loss probability distribution is generated from the capacity loss probability distribution as follows:

$$\Pr[\text{capacity loss} \geq m] = \Pr[m] + pr[m+1] + \ldots \Pr[n]$$

where,

m = any given magnitude of Forced Outage
n = total Peaking Capability of System

This results in:

$$\Pr[\text{capacity loss} \geq 0] = 1.0$$

(2) The effect on the capacity loss probability distribution of any resource described in clause 8(b)(3)(A)(iv), *Shared Resource,* shall be computed in accordance with the following:

(A) The probability of capacity loss for each of the participants shall be determined with all such resources excluded.

(B) The probability of capacity loss for the participants, as a group, shall be determined both with and without each such resource, and with the participants' shares of other such resources being included.

(C) For each such resource the difference in capacity loss calculated in 1(a)(2)(B) above for each given probability shall be divided among the participating Parties according to their share of the output of such resource, and such quantity of capacity loss for each given probability shall be added to the amount of capacity loss for the same probability as determined in 1(a)(2)(A) above. Such procedure shall be repeated for a sufficiently large number of probabilities to result in an accurate probability distribution.

(b) Peak Load Probabilities

The Peak Load probability distribution for the weekday Peak Loads in any Period shall be assumed to be a normal, or Gaussian, distribution. Weekend Peak Loads shall not be considered. The Peak Load for any Period shall be assumed to have been estimated on the basis that the probability of a higher (or lower) Peak Load is one-half; that is, it will be assumed that the Peak Loads for the various Periods are estimated such that the estimate will be too high in half the Periods and too low in half the Periods. With these assumptions, and given the standard deviation of such distribution, the characteristics of a System's Peak Load probability distribution for any quantity of forecasted Peak Load may be determined. The number, R, of standard deviations above the mean of a normal probability distribution at which the expected value of the highest observation of various likely sample sizes occurs is given as follows:

Observations in sample	R
8	1.42
9	1.49
10	1.54
11	1.58
12	1.63
13	1.67
14	1.70
15	1.74
16	1.76
17	1.79
18	1.82
19	1.84
20	1.87
21	1.89
22	1.91
23	1.93
24	1.95
25	1.97

Thus, if the standard deviation, σ, of the Peak Load probability distribution (expressed in per unit of the mean) and the number of weekdays, w, in a given Period are known, the mean, x, of the Peak Load probability distribution may be found from the forecasted Peak Load, P, of the Period by:

$$x = P / (1.0 + R_w\sigma)$$

and the standard deviation (expressed in terms of power) is obtained by multiplying x by σ. These two parameters describe fully the Peak Load probability distribution. With forecasted reserve defined as the difference between available Peaking Capability, C, and forecasted Peak Load, a Peak Load probability distribution may then be constructed; for any assumed value of forecasted reserve:

$x = (c - \text{forecasted reserve}) / (1.0 + R_w\sigma)$

(c) Load Loss Probabilities

The load loss probability distribution defines the probability of load loss for any value of forecasted reserve. The actual amount of reserve, or margin, at any time is:

$\underline{M} = C - \underline{L} - \underline{O}$

$\quad = C - (\underline{L + O})$

where,

$\underline{M}$ = margin (a probability distribution)

C = available Peaking Capability (a constant)

$\underline{O}$ = Forced Outage (a probability distribution)

$\underline{L}$ = Peak Load (a probability distribution)

The probability of load loss for any given forecasted reserve, which defines $\underline{L}$, is the probability of margin being less than zero; that is, it is the area of $\underline{M}$ to the left of zero. The method described herein for this determination is to find the probability of $(\underline{L + O})$ being greater than C by convolving the Capacity Loss distribution and the Peak Load distribution, as follows:

(1) The capacity loss probability distribution is determined and, from it, the cumulative capacity loss probability distribution.

(2) A Peak Load probability distribution is determined for each of the assumed values of forecasted reserve (selected at frequent intervals in the range likely to be significant; for example, one percent intervals in the range zero to fifty percent).

(3) Each such Peak Load probability distribution is divided into intervals (of, say, 0.1 standard deviations from -5.0 to + 5.0 standard deviations) defining assumed discrete Peak Loads such that the Peak Load representing each interval is assumed to have a value equal to the center of area of such that the Peak Load representing each interval is assumed to have a value equal to the center of area of such interval and a probability equal to the area of such interval.

(4) For each of the discrete Peak Loads, L_i, computed for each value of forecasted reserve, the amount of capacity loss, O_i, which would result in load loss is determined. The sum of the products of the probability associated with each L_i and the cumulative probability associated with the corresponding $O_{i,}$ then, is the probability of load loss for such value of forecasted reserve.

(5) By computing such a sum of cross products for each value of forecasted reserve, the load loss probability distribution is determined.

2. Allocation of Forced Outage Reserve

(a) The allocation of a given Coordinated System Forced Outage Reserve in a Period to the various Systems shall be as follows:

(1) A load loss probability distribution shall be determined for each System for such Period.

(2) The amount of forecasted reserve for each System shall be determined such that:

(A) The sum of such forecasted reserves for all Systems equals the given Coordinated System Forced Outage Reserve.

(B) The quantity of forecasted reserve selected for each System corresponds to the same probability of load loss (hence, the "isoprobability method") for all Systems.

(3) Such amount determined for each System shall be that System's Forced Outage Reserve for such Period, if such Period is within the Critical Peaking Period.

(b) Any Party whose System, although fully integrated, is not entirely within the Coordinated System shall be included as follows:

(1) The Coordinated System Forced Outage Reserve in any Period shall be initially determined as if the entire system of such Party were included therein.

(2) The load loss probability distribution for such Party, as described in 2(a) above, shall be computed as if the entire system of such Party were included.

(3) The Forced Outage Reserve for such Party in such Period shall bear the same proportion to the quantity of forecasted reserve allocated to such system in 2(a)(2)(B) above as the Peaking Capability of that part of such system included in the Coordinated System bears to the total Peaking Capability of such entire system. The remainder of such forecasted

reserve shall be assumed to be available on the portion of such system not included in the Coordinated System.

(4) The Forced Outage Reserve of the Coordinated System initially determined in 2(b)(1) above shall be reduced by such remainder.

If such Party elects, on notice to all other Parties hereto, to include such portion of its system not included in the Coordinated System for the sole purpose of contributing to and benefiting from the provisions of this agreement pertaining to Forced Outage Reserve, the remainder of forecasted reserve as determined in 2(b)(4) above shall be added to the Forced Outage Reserve of such Party and the Coordinated System. Notwithstanding the provisions of subsection 6(f), *Modified Load and Firm Resource Data,* and subparagraph 6(h)(6)(B), *Determination of Firm Peak Load Carrying Capability*, such Party may, at the time of such determination, increase an indicated import of firm capacity from the portion of its system outside the Coordinated System by the amount of such remainder, and such increase shall be considered a Firm Resource for the purpose of determining Firm Peak Load Carrying Capability. The provisions of subsection 9(n), *Transfers due to Forced Outage,* shall be extended, upon such election and subsequent adjustments, to include all of such Party's system.

Exhibit G

Forced Outage Rates

The first Exhibit G will be published to reflect Forced Outage Rates submitted by the Parties pursuant to paragraph 6(f)(5), *Forced Outage Rates*.

Exhibit H
Peak Load Characteristics

Summary of Estimated Sigmas in Percent of Mean Weekday Peak

Party	Jan.	Feb.	Mar.	Apr 1	Apr 2	May	June	July	Aug 1	Aug 2	Sept.	Oct.	Nov.	Dec.
Coordinated System	0.049	0.061	0.049	0.048	0.038	0.037	0.022	0.022	0.021	0.020	0.018	0.061	0.063	0.057
Montana	0.057	0.051	0.063	0.034	0.036	0.040	0.045	0.036	0.028	0.047	0.036	0.048	0.050	0.063
PacifiCorp	0.028	0.032	0.032	0.028	0.031	0.020	0.041	0.028	0.025	0.027	0.032	0.035	0.047	0.041
Portland	0.054	0.078	0.062	0.065	0.055	0.047	0.052	0.053	0.056	0.039	0.037	0.074	0.062	0.066
Puget	0.077	0.078	0.063	0.064	0.063	0.069	0.038	0.018	0.022	0.015	0.035	0.093	0.082	0.080
Washington	0.060	0.089	0.071	0.051	0.041	0.046	0.047	0.063	0.057	0.048	0.040	0.074	0.072	0.070
Chelan	0.055	0.066	0.058	0.049	0.045	0.044	0.045	0.040	0.037	0.035	0.036	0.065	0.062	0.064
Grant	0.058	0.077	0.065	0.055	0.058	0.077	0.061	0.065	0.043	0.052	0.069	0.056	0.088	0.089
Douglas	0.088	0.107	0.081	0.096	0.095	0.070	0.092	0.072	0.073	0.074	0.054	0.098	0.097	0.080
Seattle	0.054	0.060	0.051	0.053	0.039	0.043	0.026	0.023	0.022	0.019	0.016	0.070	0.065	0.066
Tacoma	0.071	0.078	0.055	0.066	0.047	0.067	0.042	0.023	0.025	0.020	0.037	0.069	0.081	0.078
Eugene	0.079	0.089	0.082	0.087	0.077	0.062	0.045	0.032	0.051	0.034	0.041	0.115	0.102	0.101
United States	0.070	0.082	0.067	0.072	0.063	0.064	0.053	0.043	0.043	0.040	0.043	0.081	0.087	0.083

Exhibit I

Scheduling Provisions

This Exhibit I contains scheduling procedures found in the Agreement, the long-term methods and procedures and the annual methods and procedures.

1. Provisions Involving the Actual Energy Regulation

Pursuant to long-term procedure part 9(b)-3.A.4., *Effectiveness,* the Study Group shall inform the Parties of updated Initial Actual Energy Capabilities ("Initial AEC") and Actual Energy Regulation Ending Elevations ("AER EE") in the most expeditious manner and in the shortest possible time. The Actual Energy Regulation ("AER") shall become effective as the Controlling Actual Energy Regulation for purposes of determining Actual Energy Capabilities ("AEC") and prescheduling energy transactions on the first business day following the day the Study Group communicates such Initial AECs and AER EEs to the Parties. The information shall be considered to be communicated the following day if communication is not initiated by 1600 hours.

Pursuant to long-term procedure part 9(b)-3.A.5., *Revisions,* within one business day after the Controlling AER becomes effective, any Party may require that the Study Group correct such AER if it contains computational or data-entry errors not caused by that Party. The Study Group shall correct such error and communicate the corrected results in the shortest possible time. The Controlling AER shall remain in effect until the corrected AER becomes effective pursuant to long-term procedure part 9(b)-3.A.4., *Effectiveness*; *provided* that if the communication of the corrected AER is initiated prior to 0600 hours the Parties shall consider the corrected AER to have been communicated on the previous business day for purposes of long-term procedure part 9(b)-3.A.4., *Effectiveness.*

2. Provisions Involving Requests for Storage Releases

Pursuant to long-term procedure subpart 9(j)-2.C.8.a., *Downstream Project Owners' Request,* during each normal business day, each downstream Project owner shall inform the Reservoir Party of the amount of storage releases it estimates it will request, if any, for the following Preschedule Day(s) by 1200 hours, and shall provide a final request by 1400 hours.

3. Provisions Involving the Federal Composite Reservoir

Pursuant to long-term procedure part 9(j)-3.J.1., *Chief Joseph Estimate,* by 0900 hours the United States shall provide the downstream Parties with an estimate of the Chief Joseph outflow.

Pursuant to long-term procedure part 9(j)-3.J.2., *Downstream Party's Request,* by 1200 hours any downstream Party intending to request Federal Composite Reservoir In Lieu shall inform the Administrator of its requested Federal Composite Reservoir total outflow, with the minimum and maximum amounts of In Lieu Energy it can accept. The Administrator shall limit such requested outflow to the downstream Party's Relative Maximum Discharge as determined in long-term procedure part 9(j)-3.C.4., *Downstream Party's Relative Maximum Discharge*.

Pursuant to long-term procedure part 9(j)-3.J.3., *The United States Response,* by 1300 hours the United States shall inform the downstream Party of the revised Chief Joseph outflow estimate and the downstream Party's Federal Composite Reservoir In Lieu Energy schedule.

4. Provisions Involving Cross-Border Flows

Pursuant to paragraph B.6.b.ii., *Preschedules,* of long-term procedure 9(p)-1., *Cross-Border Flows*, an Initiating Party shall notify affected downstream Parties and the Project owners of any Flow Deviation(s) during the preceding day(s) for which notification has not been provided. The Initiating Party shall use its best efforts to notify the Returning Parties and Project owners by 1000 hours of the amount of the Flow Deviation. By 1100 hours the Project owners and Returning Party shall establish preschedules based on such Flow Deviation information.