Non-Federal Participation in AC Intertie Final Environmental Impact Statement Volume2:Appendices

Bonneville DOE/eis-0145
POWER ADMINISTRATION January 1994

Non-Federal Participation in AC Intertie
Draft Environmental Impact Statement

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#Appendix A Life of Facilities Capacity Ownership Proposal

Attachment A

LIFE-OF-FACILITIES
CAPACITY. OWNERSHIP ALTERNATIVE 1/ 2/

1. Term. Capacity ownership agreements would be effective upon execution and would continue in effect for the life of any of the Northwest AC Intertie facilities.

2. New Owners' Share of Capacity Until 2016/2025. SPA would offer to the Pacific Northwest Scheduling Utilities 3/ 21 percent 4/ of SPA's total bidirectional AC Intertie transfer capability after installation and energization of the plan of service for the Third AC Intertie until termination of the Bonneville Power Administration (BPA)/Pacific Power and Light Company (PP&L) Intertie Agreement in either 2016 or 2025. New Owners would receive 21 percent of BPA's total AC Intertie rated transfer capability (RTC) and accordingly, on any hour, 21 percent of BPA's total AC Intertie operational transfer capability (OTC). New Owners would have the right to net their schedules.

1/ The reference to 21 percent is based on the assumption of full subscription (725 MN). If there is less than full subscription, then the percentage referred to in this document would change accordingly. The reference to New Owners is to the combined total responsibility/rights of New Owners. An individual owner's responsibility/rights would be based on a pro rata share of the total subscribed amount. The 21 percent also refers to the percentage of RTC immediately following energization of the Third AC Intertie. The percentage would vary according to the extent of participation by the New Owners in future upgrades and post 2016/2025 options.

2/ Whenever there are references to percentage of RTC available in this document, the same percentages apply to OTC available.

3/ Scheduling Utility means a Northwest non-Federal utility which serves a retail service area in the Northwest and which operates a generation control area within the Northwest, or any utility designated as a BPA "computed requirements customer," or âPNN utilities who become "computed requirements customers" consistent with section 13 of the BPA power sales contract. A Pacific Northwest utility would be required to become a "computed requirements customer" prior to executing a capacity ownership contract with BPA, but not before that time. BPA would also consider proposals from joint agencies or similar organizations made up of BPA PNW utility customers, which include either a PNW Scheduling Utility or a contract with a PNW Scheduling Utility for scheduling services.

4/ Twenty-one percent represents 725 MN. The formula to determine 21 percent is 725 MN divided by 3450 MN, with 3450 MN being BPA's share of the 4800 MN AC Intertie capacity after completion of the Third AC Intertie.

3. New Owners' Share of Capacity After 2016/2025. Prior to expiration of the BPA/PP&L Intertie Agreement, BPA would use its best efforts to execute replacement contracts with PP&L or its successors that provide transfer capability on term and conditions similar to that provided to BPA and New Owners prior to expiration of the BPA/PP&L Intertie Agreement. Subject to the following sentences, New Owners would have the right to own 2l percent of BPA's share of the post-2016/2025 AC Intertie transfer capability. If BPA must ,ncur additional costs properly attributable to AC Intertie transfer capability in connection with the replacement contracts, New Owners would have the option to either pay their share of 21 percent of the additional costs BPA must incur or choose to decline to pay such amount and obtain 21 percent of what transfer capability would have been in the absence of the new arrangements included in the new PP&L/BPA agreement. If BPA obtains additional benefits properly attributable to AC Intertie transfer capability in connection with the replacement contracts, New Owners would receive 21 percent of such benefits If they have not chosen to decline the replacement contracts and instead obtain 21 percent of what transfer capability would have been in the absence of the new arrangements Included in the new PP&L/BPA agreement.

If BPA and PP&L do not execute a new Intertie agreement, BPA may, in consultation with New Owners, decide to operate the AC intertie at whatever capacity would exist at that time and New Owners would have 2l percent of BPA's share of then-existing AC Intertie RTC. Subject to any necessary approval by other Intertie owners. New Owners would also have an option to construct interconnecting facilities to obtain additional transfer capability, paying the capital cost of such facilities and to otitain all such additional transfer capability; provided. that no such facilities shall adversely affect the transfer capability of then-existing AC Intertie facilities; and provided, further, that if the best plan of service requires addition of facilities that result in an RTC increase greater than that needed by owners to-maintain their pre-2016/2025 RTC, then, prior to construction, New owners shall offer BPA a first right of refusal to such increased RTC for a pro rata share of the cost of the new facilities. If BPA refuses such offer, New Owners have the right to proceed with the plan of service and retain such increased RTC.

If BPA and PP&L do not execute a new Intertie agreement, BPA may, in consultation with/New Owners, decide to construct new transmission facilities which would increase the then-existing AC-Intertie capacity. In that event, New Owners would have the right' to elect to pay 21 percent of BPA's share of the costs of construction and to receive 21 percent of BPA's share of AC Intertie transfer capability after the construction, or decline such option and obtain 2l percent of what transfer capability would have been in the absence of such new facilities.

In any event, other mutually agreeable arrangements could be worked out among Intertie owners and New Owners.

4. Management and Operation. To assist BPA and the New Owners In addressing, in an orderly way, matters arising under the capacity ownership

agreement, BPA would use its best efforts to obtain Portland General Electric's (PGE) consent to New Owners having representation and input at all meetings of the Management, Operation and Scheduling, and Engineering Committees, as established by the BPA/PGE Intertie Agreement, Contract No. DE-MS79-87SP92340, or any such committees that would be separately formed by BPA.

BPA would be the operator of the AC Intertie. As such, SPA would be responsible for the dispatch of the AC Intertie in accordance with Prudent Utility Practice and the principles for operation developed by the Operation and Scheduling Committee established under the PGE Intertie Agreement or the committees separately formed by BPA. The duties of the operator include, but are not limited to, determining: (1) the OTC of the AC -intertie; (2) emergency outages; and (3) switching orders. In making such determinations, BPA would give fair consideration to any interests of a New Owner to the extent they have been expressed in writing. BPA would operate, manage, and maintain the

AC Intertie in a good faith effort to avoid imposing inequitable costs on New Owners, consistent with contractual requirements and Prudent Utility Practice.

Except in the case of emergency or when otherwise impractical, BPA would give each of the New Owners written notice, a reasonable period in advance, of proposed actions which would significantly affect the amounts to be paid by New Owners. BPA would provide a forecast of expected annual operation and maintenance expenditures and capitalized replacements and would provide notice of any significant deviations from the forecast. Nothing in this section would obligate 8PA to provide written notice regarding plans proposed before the effective date of a capacity ownership agreement. Nothing in this section would give 8PA the right to take action inconsistent with a capacity ownership agreement. Notice of scheduled or planned maintenance and outages will be given in accordance with the accepted standards for notice on the AC Intertie. During planned outages, BPA will, to the extent possible, share available capacity with the New Owners for firm transactions that would otherwise be interrupted.

5.a. Annual O&M. New Owners would pay 21 percent through 2016/2025, and a percentage equal to their percentage of 8PA's AC Intertie capacity ownership after 2016/2025, of 8PA's annual operations, maintenance, and general plant expense (including applicable overheads> properly chargeable to the AC Intertie facilities.

5.b. Capitalized Replacements. New Owners would pay, up front, 2l percent through 2016/2025. and a percentage equal to their percentage of BPA's AC Intertie capacity ownership after 2016/2025, of BPA's share of capitalized replacements on the AC Intertie at the time such replacements are made. Or, alternatively, BPA may determine that these costs would be paid annually.

6. Remedial Actions. BPA would coordinate development of a plan for remedial actions with New Owners, including but not limited to generator dropping, required to support the RTC of BPA's share of the AC Intertie. Each party shall be financially responsible for or make arrangements for generator

dropping or other remedial actions required to maintain such RTC. New Owners would be responsible for a capability to arm 21 percent of BPA's share of the AC Intertie remedial actions. Regarding arming of that capability at any time, New Owners would be responsible to arm generation equal to a fraction, the numerator of which is such party's schedule of power under this agreement at such time and the denominator of which is the total schedule of power on the AC Intertie at sâuch time, multiplied by the total generation to be armed for the AC Intertie at such time.

7. Reinforcements of AC Intertie Facilities to Maintain Initial RTC. The parties would jointly study the RTC from time to time, and if the RTC prior to 2016/2025 becomes less than. 95 percent of the original RTC, reinforcements of the AC Intertie facilities would, unless otherwise agreed by the parties, be made, if and to the extent such reinforcements are feasible and are consistent with Prudent Utility Practice and with BPA's Intertie Agreements with PGE and PP&L and would raise the RTC to at least equal the original RTC. BPA's cost of these reinforcements would be equitably allocated among BPA and the New Owners, with such equitable cost allocation based on factors including but not limited to load responsibility, contractual responsibility and generation integration responsibility.

8. Interconnection Agreement. BPA would use its best efforts to obtain and maintain in effect an interconnection agreement with owners of AC Intertie capacity in California so as to maximize RTC and OTC, consistent with Prudent Utility Practice and with BPA's Intertie Agreements with PGE and PP&L.

9. Scheduling and Operation. Each of the New Owners would submit schedules to the Joint Intertie scheduling office. BPA would be the operator, and as such would use its best efforts to maximize RTC and OTC, consistent withâPrudent Utility Practice and with BPA's Intertie Agreements with PGE and PP&L, and would give fair consideration to each New Owner's interests to the extent they have been expressed to BPA in writing.

10. Upgrades. Any plans for upgrades of AC Intertie facilities would be developed by BPA consistent with its Intertie Agreements with PGE and PP&L, in consultation with the New Owners. New Owners would have an option to participate in BPA's AC Intertie capacity increa-ses resulting from upgrades of the AC Intertie facilities and pay 21 percent of BPA's share of the capital and O&M costs and get 21 percent of BPA's increased transfer capability.

11. Wheeling To and From AC Intertie for Initial RTC. To the extent that BPA has sufficient capacity in excess of its needs and obligations at the time capacity ownership agreements are executed, BPA would make available, through existing or new contracts to each New Owner, network wheeling between

AC Intertie and the New Owner's system in an amount equal to each new Owner's share of RTC exclusive of upgrades. Such network wheeling would be for 20 years and be of the same quality as, and on terms and conditions consistent with that being offered to other customers similarly situated. At the end of the 20 years, BPA will offer to extend wheeling of the same quality as, and on terms and conditions consistent with, that being offered at that time to other customers similarly situated.

12. Wheeling To and From AC Intertie for Upgrade Share. To the extent that BPA has capacity in excess of its needs and obligations at the time upgraded capacity is being offered, BPA would make available, through existing or new contracts to each New Owner, network wheeling between the AC Intertie and the `New Owner's system in an amount equal to each New Owner's share of any amount of RTC in excess of New Owner's share of RTC prior to the upgrade. Such network wheeling would be of the same quality as, and on terms and conditions consistent with, that being offered to other customers similarly situated.

13. Third-Party Wheeling

Alternate A. A New Owner would forego the right to use its OTC to transmit power for third parties (through direct wheeling or through arbitrage by simultaneously purchasing power and reselling such power) and allow any of its unused capacity to revert to BPA. In such case, BPA would pay the New Owner a pro rata share of all of the wheeling revenues which BPA receives from providing short-term transmission to other utilities on the AC Intertie. The prohibitions on transmitting power for third parties In this paragraph shall not be interpreted as a general prohibition against any New Owner purchasing power solely to serve its native load requirements and selling its own displaced power to other utilities.

New Owners who select this alternative retain rights to access BPA AC Intertie capacity under BPA's Long-Term Intertle Access Policy (LTIAP) or its successor.

Alternate B: A New Owner may use its oTC to transmit power for third parties. Either BPA or the New Owner, at its discretion, may make its unused OTC available to the other party.

New Owners who select this alternative must waive access to BPA AC Intertie capacity under BPA's LTIAP or-its successor.

14. Price and Payment for Capacity Ownership. The price to be paid for capacity ownership at contract execution is $2115/kW (in 1993 dollars), using mid-1989 estimates. This price would be adjusted after completion of the Third AC Intertie, to reflect (1) differences, in $/kW, between estimated and actual costs of facilities (including BPA's normal allocation of corporate overhead and Indirect expenses) shown in Table 1; (2) allowance for funds used during construction (AFUDC); and (3) the discount for early payment. This adjustment is expected to be calculated approximately 2 years after completion of the Third AC Intertie. New Owners would then either receive a refund from BPA or make an additional payment to BPA.

New Owners would make an initial lump sum payment of $215/kW, to be discounted as described in the next two sentences, at the time capacity ownership agreements are executed with BPA. This initial lump sum payment would reflect a discount for payment prior to the estimated completion date of

the Third AC Intertie. The discount would be computed for the time between the date of the lump sum payment and the expected energization date using BPA's weighted average interest rate on bonds outstanding with the U.S. Treasury.

15. Protected Areas. New Owners would not use RTC for transmission of power from new hydroelectric projects which are constructed in Columbia River Basin Protected Areas after designation thereof by BPA in the LTIAP or its successor. unless the New Owner is required by regulatory authority to purchase the output of such project or unless BPA receives sufficient demonstration that a particular project would provide benefits to existing or planned BPA fish and wildlife investments or the Pacific Northwest Electric Power and Conservation Planning Council's Fish and Wildlife Program as described in BPA's LTIAP. Remedies for violation of this commitment will be addressed in capacity ownership agreements.

Should BPA adopt a policy regarding protection of critical fish and wildlife habitat from new hydroelectric development both within and outside the Columbia River Basin prior to entering into capacity ownership agreements, that policy. as well as remedies for its violation, will be reflected in those agreements.

16. BPA's Firm Obligation to Serve. In making any determination, under any contract executed pursuant to Section 5 of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. . 839 (1982), of the electric

power requirements of any New Owner which is a non--Federal entity having its own generation, in addition to hydroelectric-generated energy excluded from such requirements pursuant to . 3(d) of `the Regional Preference Act, 16 U.S.C. . 837b(d), BPA would exclude any amount of energy disposed of by such customer outside the region if such energy Is included in the resources of such customer or other BPA customers for service to firm loads in the region and as a result of such disposition the firm energy requirements of such customer or other BPA customers placed on BPA are increased: provided, however, such amount of energy shall not' be excluded if the Administrator determines that through reasonable measures such amount of energy could not be conserved or otherwise retained for service to regional loads.

Further, BPA would exclude, in making any such determination, any amount of energy disposed of by such customer outside the region if such energy is not included in the resources of such customer or other BPA customers for service to their firm loads in the region, unless BPA is offered a first right of refusal to acquire such resource under similar terms and conditions (except terms relating to price). The price BPA would pay for any such resource would be based on the cost of the resource (including but not limited to the cost of capital, general plant, and applicable overheads) or system capability plus a reasonable rate of return.

17. Sale or Reassignment. The agreement or any interest therein shall not be transferred or assigned by either party to any party other than the

government or an agency thereof, except that BPA hereby consents to security assignment or other like financing arrangements.

18. Points of Interconnection. New Owners would be able to schedule power at either the Malin or Captain Jack substations consistent with BPA's rights under its Intertie Agreements with PGE and PP&L.

19. Losses. Average losses on net schedules on the Network and AC Intertie would be calculated according to BPA's standard practice.

20. Existing Intertie Agreements. BPA would use its best efforts to maintain New Owners' rights under their capacity ownership agreements by making no modification to BPA's Intertie Agreements with PGE and PP&L which would have a negative impact on New Owners without their prior written consent.

21. Prudent Utility Practice. Operations. maintenance, reinforcements, and upgrades of AC Intertie facilities shall be consistent with Prudent Utility Practice.

Facilities' Costs Subject to Adjustment Upon Completion of the Third AC Intertie in Determining Adjusted Final Price for Capacity Ownership ($ in thousands) Table A-1

		BPA's Costs (Est.)	BPA's Costs Actual
*/1			
Facilities whose costs will be adjusted using Change Between Estimate and Actual divided by 725 MN			
1.	Alvey (Marion-Alvey Caps)	$ 5,739	
2.	Slatt (Loop in - Breaker>	3,044	
3.	Grizzley (BPA Breakers)	11,044	
4.	Loop into Slatt	656	
5.	Halin-Meridian loop into Captain Jack	982	
6.	Alvey Substation - BPA	8,168	
7.	Dixonville - PP&L	8,635	
8.	Meridian - PP&L	6,548	
9.	Power System Control - BPA	3,575	
10.	Alvey-Spencer - BPA	1,346	
11.	Spencer-Dixonville - PP&L	20,388	
12.'	Dixonville-Meridian - PP&L	32,140	
	Subtotal	$102,265	
Facilities whose costs will be adjusted using Change Between Estimate and Actual, multiplied by 50 percent, and divided by 725 MW			
13.	Captain Jack (BPA Breakers)	$ 14,335	
14.	Captain Jack (Communication and Control)	5,100	
15.	Captain Jack (Series Capacitors)	722	
16.	Power System Control -	5,596	
17.	Captain Jack line to Oregon-California border	5,724	
	Subtotal	$ 31,477	
	Total	$133,742	

*/ Actual costs will not be available until approximately two years after completion of the Third AC Intertle.

ALTERNATIVE ALLOCATION METHODOLOGIES FOR NON-FEDERAL PARTICIPATION IN THE AC INTERTIE

Methods for Determining Negotiation Allocations for AC Intertie Capacity Ownership

BONNEVILLE POWER ADMINISTRATION
DRAFT: JUNE 5,1992

Revised based on the September 15, 1992; "Comment Summary and Response to Comments," and with the January 22, 1993, "Proposed Process for Allocations and Contract Negotiations" attached.

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A Special MOU Contingencies - (PNGC and Tacoma)
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Alternative Allocation Methodologies for Non-Federal Participation
in the AC Intertie

Section t. 8ACKGROUNO. Bonneville Power Administration (BPA) is in the process of developing a non-Federal Participation Draft Environmental Impact Statement (Draft eis), pursuant to the National Environmental Policy Act, which will address the environmental and economic effects of alternative methods of offering AC Intertie capacity rights to Northwest non-Federal utilities upon completion of the Third AC Intertie project. BPA's preferred alternative is to offer Pacific Northwest Scheduling Utilities life-of-facilities capacity ownership of 21 percent (or an expected 725 MN) of
BPA's share of the AC Intertie upon completion of the Third AC Intertie project. During September through November of 1991, BPA executed Memoranda of Understanding (MOU) with Il Northwest utilities and customer groups. The MOUs outline the parameters of the Life-of-Facilities Capacity Ownership Alternative (Capacity Ownership), describe BPA's process related to environmental analyses, and set forth understandings and intentions regarding potential contract development activities, rate case proceedings, and each utility's interest in Capacity Ownership.

After completing the Capacity Ownership MOUs with all interested parties, BPA determined the cumulative level of interest in Capacity Ownership to be between 1170 MN and 1542 MN. This interest significantly exceeds the 725 MN of Capacity Ownership BPA may offer, and BPA must devise a method to allocate the 725 MN among the interested utilities. BPA has identified four alternative allocation methodologies to be analyzed in BPA's preferred alternative in the `Draft eis. Only the preferred alternative may require the application of an allocation methodology.

BPA has designated its preferred allocation methodology in this paper. BPA proposes to apply the preferred allocation methodology selected after comment processes are completed as the basis for determining initial negotiation allocations for Capacity Ownership contract negotiations. Final allocated amounts will be determined in executed Capacity Ownership contracts after completion of the environmental review process and the Administrator's Record of Decision.

Section 2. EXECUTED AGREEMENT WITH A SOUTHWEST UTILITY. For a utility to qualify for an allocation of Capacity Ownership, BPA will require the utility,
by close of public comment on the Draft eis, to provide BPA a copy of the

utility's executed agreement with a Southwest utility (Attachment A discusses additional contingencies for PNGC and Tacoma). BPA will require a copy of such agreement regardless of whether the utility has a contingent or non-contingent MOU. or whether BPA will need to apply an allocation methodology.

A utility should submit an executed agreement for a long-term firm power sale, seasonal exchange, or other similar arrangement with a Southwest utility. Such an agreement should include all major terms and conditions including, but not limited to, term, price, and quantity. If the agreement provided to BPA does not constitute the final written agreement between the parties, the agreement must also include a commitment to execute such final agreement. An unexecuted or draft agreement, or an agreement which is not a power sale or a seasonal exchange or similar arrangement, will not constitute an executed agreement with a Southwest utility.

(The following underlined language is incorporated from the September 15, 1992, comment summary and response to comments:) BPA will require that executed agreements with Southwest utilities be final and legally enforceable, containing all major terms and conditions including, but not limited to, term, price (which does not need to be disclosed to BPA), and quantity. Such agreements should also provide for the delivery of power from a resource existing or under construction at the time agreements are submitted to BPA. Executed agreements contingent upon the delivery of power from a resource not existing or under construction at that time will also be accepted; however, for allocation purposes, such agreements will be considered as requests for capacity ownership for unspecified transactions, described in Section 3 of BPA's June 5 paper.

A utility may execute multiple agreements with a Southwest utility or utilities provided that the MW total of the utility's executed agreements is less than or equal to the utility's MW interest expressed in its MOU with BPA. If a utility does execute multiple agreements with a Southwest utility or utilities, the agreements may be submitted to BPA individually or collectively but must be submitted by close of public comment on the Draft eis.

Requiring utilities with contingent MOUs to provide executed agreements to BPA by close of public comment on the Draft eis is consistent with the understanding in all contingent Capacity Ownership MOUs. While utilities with non-contingent MOUs do not have such language in their MOUs, it is in BPA's interest to know, prior to committing significant time to Capacity Ownership contract negotiations, that such utilities have executed agreements with Southwest utilities.

Section 3. REQUEST FOR CAPACITY OWNERSHIP FOR UNSPECIFIED TRANSACTIONS. In the event' that, upon close of public comment on the Draft eis, BPA has received less than 725 MN of executed agreements with Southwest utilities, BPA would make the remainder of the Capacity Ownership available for unspecified transactions.

A utility desiring Capacity Ownership for unspecified transactions may request such Capacity Ownership by submitting to BPA a letter stating the utility's MN interest in such Capacity Ownership. BPA will require receipt of this letter by the close of public comment on the Draft eis. If a utility has not submitted to BPA an executed agreement with a Southwest utility, the utility may request Capacity Ownership for unspecified transactions for a MN amount up to the utility's MOU amount. If a utility has executed such an agreement, the utility may request Capacity Ownership for unspecified transactions if the MN amount of the sum of the utility's executed agreement with a Southwest utility and the request for Capacity Ownership for unspecified transactions is less than or equal to the utility's MOU amount. For example, if a utility with a 50 MN MOU amount does not submit to BPA an executed agreement with a Southwest utility, the utility may request Capacity Ownership for unspecified transactions for up to SO MN. If a utility with a 200 MN M0U interest in Capacity Ownership submits a 150 MN executed agreement with a Southwest utility or utilities, the utility may submit to BPA a letter requesting up to SO MN, of Capacity Ownership for unspecified transactions.

If, upon close of public comment on the Draft eis, BPA has received less than 725 MN of executed agreements with Southwest utilities, BPA would allocate the remainder of the 725 MW, on a pro rata basis if necessary, to those utilities that submitted requests for Capacity Ownership for unspecified transactions. Utilities receiving such allocations would still need to satisfy the requirements discussed in Section 6, "Requirements Prior to Negotiating Capacity Ownership Contracts with BPA."

Section 4. AC INTERTIE TRANSFER CAPABILITY RATINGS. BPA is proposing to offer non-Federal utilities Capacity Ownership of 21 percent of BPA's share of bidirectional Rated Transfer Capacity (RTC) of the AC Intertie upon completion of the Third AC Intertie project. It is expected that the north-to-south RTC of the AC Intertie will be 4800 MN upon completion of the Third AC Intertie project and that the south-to-north RTC will be 3600 MN. Studies currently underway among Northwest and Southwest owners of the AC Intertie are showing that it may be possible to achieve a higher south-to-north RTC than 3600 MN.

Final studies regarding the possibility of increased south-to-north RTC are not expected to be completed until March 1993. Depending on the status of south-to-north RTC studies at the time BPA would have to apply a Capacity Ownership allocation methodology. BPA would consider the effects of any increased south-to-north RTC prior to allocating. BPA is proceeding on the assumption that the south-to-north RTC of the AC Intertie will be 3600 MN upon completion of the Third AC Intertie project. If a utility were to receive a Capacity Ownership allocation, and because of a lower south-to-north RTC the utility's south-to-north allocation was insufficient to accommodate the symmetry of the utility's seasonal transaction, BPA would consider (two options] the following options: (1) offering the utility a limited south-to-north AC Intertie wheeling service; and/or (2) providing the utility a large enough north-to-south allocation such that the resulting south-to-north [allocation] capacity would be sufficient to accommodate the symmetry of the seasonal transaction.

Section 5. ALLOCATION METHODOLOGIES.

Objectives. The guiding objectives in developing the allocation methodologies and requirements were to create a mechanism which achieves fair and equitable allocations among the utilities, provides the greatest West Coast-wide benefits, and assures that Capacity Ownership is as similar to actual physical ownership as `possible. BPA's more specific objectives are to (1) increase transmission access for the greatest possible number of utilities in the Northwest and promote competition; (2) give reasonable consideration to the understandings set forth in the Capacity Ownership MOUs; (3) use staff time efficiently by negotiating only with utilities that demonstrate significant commitment to Capacity Ownership by executing agreements with Southwest utilities; and (4) develop allocation methodologies which are understandable to the utilities involved and administratively workable for BPA.

Criteria. In consideration of the above objectives, BPA has identified certain criteria which are applied in alternative methods within the allocation methodologies. Not all of the allocation methodologies apply the criteria. The criteria are defined as follows:

Intertie Owner Status "Intertie Owner Status" distinguishes between current Intertie owners and non-owners. This criterion promotes the objective of increasing transmission access for the greatest number of utilities and promoting competition. This criterion is applied in Allocation Methodologies 3A and 35.

MOU Type: "MOU Type" distinguishes between utilities that executed contingent MOUs and non-contingent MOUs. This criterion promotes the objective of giving reasonable consideration to the understandings set forth in Capacity Ownership MOUs. Specifically, this criterion would give priority to those utilities that signed non-contingent M0Us. Utilities that signed non-contingent M0Us demonstrated a high level of commitment, providing BPA additional reassurance to move forward with the non-Federal participation process. This criterion is applied in Allocation Methodologies 2, 3A, and 3B.

Intertie Use: "Intertie Use" considers the various possible uses of Capacity Ownership and identifies "preferred" uses. This criterion would give priority to interregional transactions that provide the most net benefits with the least costs. Such transactions would increase efficiency of power use in both regions. Examples of preferred uses are as follows: (1) long-term seasonal exchanges; and (2) long-term power sales of existing surplus with recall rights. This criterion is applied in Allocation Methodology 3A.

Application. An allocation methodology would be applied in the event that, by close of public comment on the Draft eis, BPA receives more than 725 MN of executed agreements with Southwest utilities. If BPA receives less than 725 MN of executed agreements, then application of an allocation methodology would not be necessary. As discussed in Section 3, "Request for Capacity Ownership for Unspecified Transactions," the remainder of the 725 MN would be allocated, on a pro rata basis if necessary, to the utilities that had expressed interest in receiving allocations for unspecified transactions.

Regardless of how or for what purpose a utility receives an allocation, prior to negotiating a Capacity Ownership contract with BPA the utility would be subject to the requirements discussed in Section 6, "Requirements Prior to Negotiating Capacity Ownership Contracts with BPA."

Allocation Methodology 1: Pro Rata

General Description. Methodology l would not apply any of the criteria described above. Utilities would not receive preference or priority based on Intertie Owner Status, MOU Type, or Intertie Use. Utilities would have until the close of public comment on the Draft eis to provide to BPA executed agreements with Southwest utilities. Section 2, "Executed Agreement with a Southwest Utility," describes requirements regarding agreements.

If, by close of public comment on the Draft eis, BPA receives more than 725 MN of executed agreements with Southwest utilities, BPA would allocate 725 MN on a pro rata basis. Utilities would receive pro rata allocations as follows: an individual utility's MN amount expressed in its agreement with a Southwest utility would be divided by the sum of the executed agreements with Southwest utilities, with the quotient being multiplied by 725 MN. Utilities would receive pro rata allocations in such a manner and would begin Capacity Ownership contract negotiations with BPA, contingent upon satisfying the requirements described in Section 6, "Requirements Prior to Negotiating Capacity Ownership Contracts with BPA." If SPA and the utility could not complete a Capacity Ownership contract on a timely basis, or if negotiations were terminated or suspended by either party, the amount of Capacity Ownership being negotiated would become available to the other utilities on a pro rata basis and the negotiation deposit (discussed in Section 6) would be refunded with interest.

Example. Assume that, by close of public comment on the Draft eis, the utilities below had submitted executed agreements to BPA for the amounts indicated. Table 1 shows how each utility would receive a pro rata allocation.

TABLE 1

UTILITY	CONTRACT AMOUNT	PRO RATA ALLOCATION
Utility 1	400 MN	400/1075 X 725 = 270 MN
Utility 2	300 MN	300/1075 X 725 = 202 MN
Utility 3	200 MN	200/1075 X 725 = 135 MN
Utility 4	100 MN	10011075 X 725 = 67 MN
Utility 5	50 MN	5011075 X 725 = 34 MN
Utility 6	25 MN	2511075 X 725 = 17 MN
TOTALS	1075 MN	725 MN

Allocation Methodology 2: Pro Rata with Non-Contingent MOO Priority

General Description. Methodology 2 would apply the MOO Type criterion. Utilities' would not receive preference for their Intertie Owner Status or Intertie Use. Utilities would have until the close of public comment on the Draft eis to provide to BPA executed agreements with Southwest utilities. Section 2, "Executed Agreement with a Southwest Utility," describes requirements regarding agreements.

Utilities with non-contingent MOUs would receive 100 percent allocations based on their agreements with Southwest utilities. The remaining unallocated Capacity Ownership would be allocated on a pro rata basis to those utilities that submitted executed agreements with Southwest utilities to BPA by close of public comment on the Draft eis.

Upon close of public comment on the Draft eis, BPA would then negotiate Capacity Ownership contracts with the utilities comprising the 725 MN of Capacity Ownership interest as allocated in Methodology 2, contingent upon completion of the requirements described in Section 6, "Requirements Prior to Negotiating Capacity Ownership Contracts with BPA." If SPA and a utility could not complete a Capacity Ownership contract on a timely basis, or if negotiations were terminated or suspended by either party, the -amount of Capacity Ownership being negotiated would become available to the other utilities on a pro rata basis and the negotiation deposit (discussed In Section 6) would be refunded with interest.

Example. Assume that, by close of public comment on the Draft eis, non-contingent MOU utilities had submitted 350 MN of executed agreements with Southwest utilities and six other utilities with contingent MOUs had submitted executed agreements with Southwest utilities in the amounts indicated. Table 2 shows how utilities would receive allocations pursuant to Methodology 2.

TABLE 2

UTILITY	CONTRACT AMOUNT	ALLOCATION
Non-Contingent MOU Utilities	350 MN	100% of 350 = 350 MN
Subtotal: Non-Contingent MOUs	350 MN	350 MN
Utility 1	50 MN	501465 X 375 = 40 MN
Utility 2	200 MN	2001465 X 375 = 162 MN
Utility 3	50 MN	501465 X 375 = 40 MW
Utility 4	40 MN	401465 X 375 = 32 MN
Utility 5	75 MN	751465 x 375 = 61 MN
Utility 6	50 MN	501465 x 375 = 40 MN

Subtotal: Contingent MOUs	465 MN	375 MN
TOTALS	815 MN	725 MN

Allocation Methodology 3A: Multi-Factored with Intertie Owner Status Priority

General Description. Methodology 3A would apply all identified criteria in series in order to determine four allocation groups. The group to which a utility is assigned would determine the likelihood of the utility receiving its MN interest in Capacity Ownership as identified in the utility's agreement
with a Soutâhwest utility. Methodology 3A prioritizes the criteria as follows: (1) Intertie Owner Status; (2) Intertie Use; and (3) MOU Type. For Intertie Owner Status, BPA would give preference to non-owners over Intertie owners. For Intertie Use, BPA would give preference to uses that fall within the scope of preferred uses. For MOU Type, BPA would give preference to non-contingent M0Us over contingent MOUs.

A utility having Intertie ownership would be assigned to Group 4. Intertie Use and MOU Type criteria would not be applied. Utilities in Group 4 would qualify for allocations, on a pro rata basis, after utilities in Group l, Group 2, and Group 3 had the opportunity to receive allocations. A utility not having Intertie ownership but executing a non-preferred transaction would be assigned to Group 3. The MOU Type criterion would not be applied. Utilities in Group â3 would qualify for allocations, on a pro rata basis, after utilities in Group l and Group 2 had the opportunity to receive

allocations. A utility not having]ntertie ownership, executing a preferred transaction, but having a contingent M0U would be assigned to Group 2. Utilities in Group 2 would qualify for allocations, on a pro rata basis. after
utilities in Group l had the opportunity to receive allocations. A utility not having Intertie ownership, executing a preferred transaction, and having a
non-contingent MOU would be assigned to Group l, and would receive a 100 percent allocation based on its agreement with a Southwest utility.

Utilities would have until the close of public comment on the Draft eis to
provide to BPA executed agreements with Southwest utilities. Section 2, "Executed Agreement with a Southwest Utility," describes requirements regarding agreements. Upon close of public comment on the Draft eis, BPA would then negotiate Capacity Ownership contracts with the utilities comprising the 725 MN of Capacity Ownership interest as allocated in Methodology 3A, contingent upon completion of the requirements described below
in Section 6, "Requirements Prior to Negotiating Capacity Ownership Contracts with BPA." If SPA and a utility could not complete a Capacity Ownership contract on a timely basis, or if negotiations were terminated or suspended by
either party, the amount of Capacity Ownership being negotiated would become available to the other utilities on a pro rata basis pursuant to the Group

priorities set forth in Methodology 3A and the negotiation deposit (discussed in Section 6) would be refunded.

Example. The following criteria, in the following order, would be applied and groups assigned (the same information is summarized in Table 3A):

1) Intertie Owner Status: non-owner or owner?
   If Intertie owner, utility is assigned to Group 4.
   If non-owner, "Intertie Use" criterion is applied:

2) Intertie Use: preferred or non-preferred use?
   If non-preferred, utility is assigned to Group 3.
   If preferred, "MOU Type" criterion is applied:

3) MOU Type: non-contingent MOU or contingent MOU?
   If contingent MOU, utility is assigned to Group 2.
   If non-contingent MOU, utility is assigned to Group 1.

TABLE 3A

Criteria	Group 1	Group 2	Group 3	Group 4
INTERTIE 0NNER STATUS	Non-Owner	Non-Owner	Non-Owner	Owner
INTERTIE USE	Preferred	Preferred	Non-Preferred	
M0U TYPE	Non-Cont.	Contingent		
ALLOC-ATION	100 %	Pro Rata After Group l	Pro Rata After Groups and 2	Pro Rata After Groups l, 2, and 3

Assume that, upon close of public comment on the Draft eis, total Group interest was 350 MN, total Group 2 interest was 200 MN, and total Group 3 interest was 300 MN. The utilities in Group l comprising the 350 MN would receive 350 MN. The utilities in Group 2 comprising the 200 MN would receive 200 MN, and the utilities in Group 3 comprising the 300 MN would receive 175 MN,
on a pro rata basis. The utilities in Group 4 would not receive allocations.

PREFERRED METHODOLOGY
Allocation Methodology 36: Intertie Owner Status and MOU Type Priority

General Description. Methodology 35 places the highest priority on Intertie Owner Status and also applies the M0U Type criterion. The sequential application is the same as in Methodology 3A, except that Intertie Owner Status
and MOU Type are the only criteria applied. Methodology 35 would assign utilities to one of three allocation groups. The group to which a utility is

assigned would determine the likelihood of the utility receiving its interest in Capacity Ownership. For Intertie 0~wner Status, BPA would give preference to non-owners over Intertie owners. For MOU Type, BPA would give preference to non-contingent MOUs over contingent MOUs.

A utility having Intertie ownership would be assigned to Group 3. MOU Type would not be applied. Utilities in Group 3 would qualify for allocations, on a pro rata basis, after utilities in Group l and Group 2 had the opportunity to receive allocations. A utility not having Intertie ownership but having a contingent MOU would be assigned to Group 2. Utilities in Group 2 would qualify for allocations, on a pro rata basis, after utilities in Group l had the opportunity to receive allocations. A utility not having Intertie ownership and

having a non-contingent M0U would be assigned to Group l and would receive a 100 percent allocation based on its executed agreement with a Southwest utility.

Utilities would have until the close of public comment on the Draft eis to provide to BPA executed agreements with Southwest utilities. Section 2, "Executed Agreement with a Southwest Utility," describes requirements regarding agreements. Upon close of public comment on the Draft eis, BPA would then negotiate Capacity Ownership contracts with the utilities comprising the 725 MN of Capacity Ownership interest as allocated in Methodology 35, contingent upon completion of the requirements described in Section 6, "Requirements Prior to Negotiating Capacity Ownership Contracts with BPA." If SPA and a utility could not complete a Capacity Ownership contract on a timely basis, or if negotiations were terminated or suspended by either party, the amount of Capacity Ownership being negotiated would become available to the other utilities on a pro rata basis pursuant to the Group priorities set forth in Methodology 3B and the negotiation deposit (discussed in Section 6) would be refunded with interest.

Example. The following criteria, in the following order, would be applied and groups assigned (the same information is su~arized in Table 35):

1) Intertie Owner Status: non-owner or owner?
   If Intertie owner, utility is assigned to Group 3.
   If non-owner, "MOU Type" criterion is applied:
2) MOU Type: non-contingent MOU or contingent MOU?

If contingent MOU, utility is assigned to Group 2.
If non-contingent MOU, utility is assigned to Group 1.

Example. Table 3B below summarizes the application of Methodology 35.

TABLE 3B

Criteria	Group 1	Group 2	Group 3
INTERTIE OWNER STATUS	Non-Owner	Non-Owner	Owner
MOU TYPE	Non-Cont.	Contingent	
ALLOC- ATION	100 Percent	Pro Rata After Group 1	Pro Rata After Groups 1 and 2

Assume that, upon close of public comment on the Draft eis, the total Group
interest was 350 MN, total Group 2 interest was 400 MN, and total Group 3

interest was 200 MN. The utilities in Group 1 comprising the 350 MN would receive 350 MN. The utilities in Group 2 comprising the 400 MN would receive 375 MN, on pro rata basis. The utilities in Group 3 would not receive allocations.

6asis for Selection of Preferred Methodology. Methodology 35 is the preferred allocation methodology because it accomplishes the greatest number of BPA's specific objectives while remaining consistent with SPA's broader, guiding objectives. Methodology 38 creates a mechanism for achieving fair and equitable allocations among the utilities interested in Capacity Ownership and, by not dictating a desired Intertie transaction such as in Methodology 3A, Methodology 38-is consistent with the objective of assuring that Capacity Ownership is as similar to actual physical ownership as possible. Methodology 38 addresses BPA's desire to increase transmission access in the Northwest, considers the understandings set forth in the Capacity Ownership MOUs, and is administratively workable.

Section 6. REQUIREMENTS PRIOR TO NEGOTIATING CAPACITY OWNERSHIP CONTRACTS WITH BPA. The utility would need to satisfy the requirements below before the utility could begin Capacity Ownership contract negotiations with BPA. If a utility did not satisfy the requirements, BPA would offer to negotiate with the next utility qualified to receive an allocation, or if an allocation methodology had not been applied, BPA would revise its allocation for unspecified transactions if all such requests had not been satisfied.

Negotiation Deposit. The utility would be required to pay BPA a refundable negotiation deposit of an amount equal to lO percent of the utility's expected

up-front payment for Capacity Ownership. The negotiation deposit would be applied to the up-front payment, with interest added from the time BPA receives the negotiation deposit until receipt of the full up-front payment, if the utility and BPA subsequently execute a Capacity Ownership contract. The negotiation deposit would be refunded, with interest, if the utility relinquished its allocation prior to Capacity Ownership contract negotiations or if Capacity Ownership contract negotiations were suspended or terminated by
the utility or BPA, unless SPA determined that the utility had made willful and material misrepresentations. The negotiation deposit is intended to serve the purpose of allowing a utility to confirm its commitment to Capacity Ownership and is not intended to be prohibitive.

(The following underlined language is incorporated from the September IS, 1992, comment summary and response to comments:) The negotiation deposit will only be required from those utilities receiving allocations. BPA will accept a letter of credit as the negotiation deposit, provided that the utility assumes all costs of obtaining the letter of credit and that BPA receives a copy of the letter of credit and finds the terms acceptable.

Summary of Financing Plan. The utility would be required to provide BPA a summary of the utility's plan for financing its interest in Capacity Ownership.

ATTACHMENT A

Special MOU Contingencies

Pacific Northwest Generating Cooperative (PNGC)

PNGC's Capacity Ownership MOU with BPA has three contingencies: (1) PNGC reaching subscription agreements with its members; (2) PNGC executing an agreement with a Southwest utility; and (3) BPA making a determination that PNGC is the appropriate contracting entity.

To qualify for an allocation of Capacity Ownership, PNGC must satisfy contingencies 1 and 2 above, and provide demonstration of such satisfied contingencies to BPA no later than close of public comment on the Draft eis. If PNGC satisfies contingencies 1 and 2 and receives an allocation under any circumstances, contingency 3 must be satisfied prior to BPA and PNGC entering into Capacity Ownership contract negotiations.

Tacoma City Light (Tacoma)

To qualify for an allocation of Capacity Ownership, Tacoma must satisfy its MOU contingency. Tacoma will need to provide BPA a written request for SPA to terminate or renegotiate Tacoma's Intertie Transmission Agreement, Contract No. DE-MS79-885P92490, contingent upon Tacoma and BPA executing a Capacity Ownership contract.

(VS10-PMTI-8OO6d)

A24

Department of Energy
Bonneville Power Administration
PO. Box 3621
Portland. Oregon 97208-3621

JAN 22 1993

In reply refer to: PMTI

Dear Capacity Ownership Memorandum of Understanding (MOU) Signatory:

Enclosed please find Bonneville Power Administration's (BPA) "Proposed Process for Allocations and Contract Negotiations" for AC Intertie Capacity Ownership (Capacity Ownership). The enclosed document supersedes all other communications on this issue, including my letter to you of October 14,1992.

At the meeting of January 6,1993, in which 8 of the 11 MOU signatories attended, the allocation and contract negotiation process was discussed in detail. Through discussion of a draft process proposed by BPA, it Was apparent that some parties had conflicting interests. BPA has considered the January 6,1993, discussion and has prepared the enclosed process. We believe the process balances interests fairly and reflects the understandings reached at the January 6,1993, meeting.

On page 1 of the enclosure, please note BPA's request that utilities submit required information as soon as possible. The deadline for submitting -such information remains March 16,1993. However, early submittal would allow BPA to provide earlier notice to utilities regarding the sufficiency of information. In particular, early submittal would allow more time for utilities and BPA to work together in the event that submitted information is insufficient

Although the enclosure does establish a process for maiang preliminary allocations for contract negotiations, no Capacity Ownership decisions will be made until completion of the Final Non-Federal Participation Environmental Impact Statement and Administrator's Record of Decision.

Also, at the January 6,1993, meeting, it was requested that BPA allow for more input from the MOU signatories in the development of the Capacity Ownership Agreement BPA is taking this recommendation under consideration. If you have any questions regarding these matters, please call me at (503)230-5852.

Sincerely,

Project Manager
Non-Federal Participation

Enclosure

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ACINTERTIE CAPACITY OWNERSHIP
PROPOSED PROCESS FOR ALLOCATIONS AND CONTRACT NEGOTIATIONS

Present - March 16, 1993

Utilities submit to BPA;

(l) Executed agreements with Southwest utilities. Utilities submit: (a) final, legally enforceable long-tertn agreements with Southwest utilities; or (b) countersigned letters of principles for long-terrn agreements with all major terms and conditions including, but not limited to, term, price, and quantity.

Tacoma City Light (Tacoma) should also submit a letter requesting BPA to negotiate an amendment to Tacoma's current assured delivery agreement to allow for Tacoma's current power sale to Western Area Power Administration to continue over a combination of reduced assured delivery and new Capacity Ownership.

(2) Anv requests for Capacity Ownership for unspecified transactions. A utility may submit a request for Capacity Ownership for unspecified transactions under either of the following conditions: (a) if the utility has not submitted an executed agreement pursuant to l above, the

utility may submit a letter requesting Capacity Ownership for unspecified transactions in an amount up to the upper bound of the utility's MOU amount; or (b) if the utility's agreement(s) submitted pursuant to l above is less than the upper bound of the MOU amount, the utility may submit a letter requesting Capacity Ownership. for unspecified transactions in an amount up to the difference between the agreement(s) and the upper bound of the utility's MOU.

(3) Resource under construction information. if applicable. If the resource proposed for export does not yet exist, the utility should submit any information available regarding the proposed resource which would assist BPA in assessing the development or construction status of the resource. Such information may include, but is not limited to, permits, licenses, financing documents, and construction schedules. Commencement of physical construction of the resource at the time information is submitted to BPA is not necessarily required. In such case, however, the information submitted must be sufficient for BPA to conclude that the resource will indeed be constructed.

BPA encourages utilities to submit information requested above as soon as possible. BPA will review submitted information and notify the utility by the earlier of 30 days from the submittal or March 30, 1993, if possible, regarding whether the information is sufficient for the utility to receive a preliminary allocation.

March 16 - April 16.1993

BPA determines whether submitted information is sufficient for mailing preliminary allocations. If, after reviewing submitted information, BPA determines that such information is insufficient for the utility to

receive a preliminary allocation, BPA will notify the utility by March 30, 1993, if possible, regarding the insufficiency, The utility would have until close of business, April 9, 1993, to submit additional information. BPA would then consider any additional information submitted before making a determination regarding sufficiency for a preliminary allocation.

Anril 16 - 21, 1993

BPA applies the preferred allocation methodology, if necessary, and sends letters notifying utilities of preliminary allocations. The letters will request that appropriate negotiation deposits and su[ninaries of financing plans be submitted to BPA, in accordance with the proposed allocation methodology, by May 7, 1993.

May 7 - 14.1993

BPA reviews preliminary allocations and may revise preliminary allocations based on whether utilities have submitted negotiation deposits and summaries of financing plans. BPA sends letters, with an attached draft Capacity Ownership Agreement, to utilities receiving preliminary allocations and submitting negotiation deposits and summaries of financing plans. The letters would include the following:

(1) Notice of preliminary allocation.
(2) Invitation to June l, 1993, negotiation meeting.
(3) Outline of proposed negotiation schedule, as follows:

Date	Process/Action
May 14-28, 1993	Utilities review draft Capacity Ownership Agreement
June 1, 1993	Initial negotiation meeting. Utilities bring lists of issues. Negotiation schedule and major issues are agreed upon.
June - September 1993	Capacity Ownership Agreement negotiations.
Record of Decision	BPA finali~s allocations and makes any adjustments necessary.
Published	BPA and utilities execute Capacity Ownership Agreements if that action is supported' by the Administrator's Record of Decision on the Final E[S.

Close of Public Comment. Draft eis (Date Uncertain)

All utilities must submit final, legally enforceable long-term agreements with Southwest utilities by this date in order to confirm preliminary allocations and proceed or continue with capacity Ownership Agreement negotiations. Public comment on the Draft eis will close approximately 45 days after its publication date.

Bonneville's Proposed
Northwest Power Act, Section 9(c)
Non-Federal Participation Policy

United States of
America

Department of Energy
Bonneville Power
Administration

Office of Power Sales
April 1993

A28

BONNEVILLE'S PROPOSED NORTHWEST POWER ACT, SECTION 9(c)
NON-FEDERAL PARTICIPATION POLICY

for Exports of Up to 725 MN of Pacific Northwest Resources
over the
Pacific Northwest-Pacific Southwest AC Intertie

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BONNEVILLE'S PROPOSED NORTHWEST POWER ACT, SECTION 9(c)
NON-FEDERAL PARTICIPATION POLICY

for Exports of up to 725 MW of Pacific Northwest Resources
over the
Pacific Northwest-Pacific Southwest AC Intertie

Introduction

In 1968, the Pacific Northwest-Pacific Southwest AC Intertie (Intertie) began operation. Among other purposes, the Intertie was constructed to provide additional markets for Bonneville Power Administration (BPA) surplus firm and nonfirm power. In addition, to the extent that there was transmission capacity In excess of Federal needs, Congress Intended that utilities in the Pacific Northwest and the Pacific Southwest take advantage of the seasonal diversity that exists between these regions by facilitating interregional exchanges.

Beginning in 1987, at the request of various parties, BPA began working with regional utilities, the Pacific Northwest Congressional delegation, the Department of Energy in Washington, DC, and the U.S. Office of Management and Budget (OMB) to create increased opportunity for regional utilities to participate in the Intertie, while helping BPA defray some of the major Federal investment in the Third AC Intertie upgrade.

In May 1988, BPA finalized its Long-Term Intertie Access Policy (LTIAP), which established various operating conditions under which both Federal and non-Federal utilities would have access to the Intertie.

In 1993, BPA's Non-Federal Participation policy goal is to ensure that the 11 Pacific Northwest public and private utilities (potential "Hew Owners") that signed a Memorandum of Understanding with BPA in 1991 have an equitable opportunity to acquire a share of 725 megawatts (MN) of transmission capacity in the Intertie, that is as close to full "ownership" as possible, which is referred to as Capacity Ownership.

In order to become a New Owner, a Pacific Northwest utility is first required to complete a contract for the sale or exchange of a regional resource with a Pacific Southwest utility and then must execute a Capacity Ownership Agreement with BPA for a share of Intertie. Whenever there is an export of a regional resource, BPA has a statutory duty under the Pacific Northwest Electric Power

Planning and Conservation Act (Northwest Power Act) Section 9(c) to determine whether the export of the New Owner's resource will result in an increase in the electric power requirements of BPA or of any of its customers and whether the resource could be conserved or otherwise retained to serve regional load in the Pacific Northwest.

If BPA finds that the export of a resource would result in an increase in the electric power requirements of any of its customers under BPA's Northwest Power Act, Section 5(b) utility power sales contracts and the resource could have been conserved or otherwise retained to serve regional loads, BPA is required to reduce its firm load obligation to deliver power and energy under the exporting utility's power sales contract effective on a date certain up to
the amount of the export sale and for the duration of such sale.

If, on the other hand, BPA finds that the export of the Pacific Northwest resource would not result in any increase in the electric power requirements of BPA for that customer or any other customer, or SPA further finds that the energy could not be reasonably conserved or otherwise retained for service to regional load by reasonable measures, then BPA will not decrease its obligation to the exporting utility under its power sales contract.

In implementing Northwest Power Act, Section 9(c), BPA must reasonably balance
the risk between BPA becoming obligated to acquire additional resources which it otherwise would not plan to serve additional load obligations, with the New Owners ability to make an export. In this proposed Section 9(c) policy, BPA will adhere to its prior case-by-case Section 9(c) policy and interpretations.

It is BPA's intent as part of its proposed Section 9(c) policy determination to address at one time any Section 9(c) issues raised by the proposed export by New Owners of up to 725 MN of regional resources, which is the maximum amount of Intertie capacity available. BPA will use its analytical tools to review the specific resources and categories of resources being exported to determine if such exports will cause load on BPA or its customers to increase and to determine whether the resource could be conserved or retained using reasonable means.

As a result of the determinations made under this proposed Section 9(c) policy, the public and New Owners will know how BPA will apply its Section 9(c) policy determinations under Public Law 96-SOl, the Northwest Power Act to those resources the New Owners initially intend to export.

1. BPA's Interests.
   BPA's Interests under the proposed policy include the following:

   - Ensuring an equitable risk-sharing of resource acquisition costs and supply between BPA,. its nonexporting customers and those utility customers who are exporting regional resources.

- Compliance with all of BPA's applicable statutory requirements.

- Compliance with all of BPA's public involvement and environmental responsibilities.

2. Prior Northwest Power Act Section 9(c) Determinations.

a. LTIAP Assured Delivery (Exhibit B).
LTIAP section 4(a)(4)(A) and (8) "Waiver of Service Obligation" requires a Pacific Northwest utility exporting under an Assured Delivery contract to agree as a condition of its Assured Delivery

contract to reduce BPA's firm load obligation to the utility engaged in the export, for a specified period, and in an energy amount equal to the amount of energy for which the Assured Delivery contract is provided. (The decrement for an export of a regional hydro resource begins immediately, while an export of a thermal resource is based on a notice from BPA that the exported resource is needed to meet requirements load in the Pacific Northwest.)

b. October 1983 - BPA/Montana Power Company.
In correspondence between BPA's Office of General Counsel and Montana Power Company (MPC), MPG asked, if in interpreting Northwest Power Act Section 5(c), BPA would reduce a customer's firm energy requirements by the amount of firm energy generated at a customer's hydroelectric project and exported outside the region, when that resource is not listed in a customer's firm resource exhibit.
BPA response was that such energy would be excluded (decremented) from BPA's firm load obligation in determining a customer's firm energy requirements. (BPA referred to the language in Section 9(c) of the Northwest Power Act, which incorporates the exclusion of hydroelectric energy from the energy requirements of Pacific Northwest customers, and the language stated in Section 3(d) of the Regional Preference Act, as authority for this policy.)

MPG then asked if energy from thermal resources would be similarly excluded (decremented) were it exported. BPA's Office of General Counsel responded that exported energy from theral proJects currently listed in a customer's firm resource exhibit similarly would be excluded. (BPA cited Section 9(c) of the Northwest Power Act as authority for this decision.)

c. BPA/Tacoma (SCBID Hydroelectric Resource).
In a March 19, 1984, letter from BPA to Tacoma City Light over the export of Tacoma's South Columbia Basin Irrigation District (SCBID)

hydroelectric resource BPA found Tacoma's SCSID resource was

conservable and could be used to meet Tacoma's energy loads in the Pacific Northwest. Tacoma was able to export its SCBID hydro resource, but Tacoma's firm power requirements on BPA were reduced in the amount of the export sale, under Tacoma's 1981 power sales contract with BPA.

BPA said the following in its letter to Tacoma:

> "* * * While BPA agrees with the City of Tacoma * * * that [S]ections 5(b) and 9(d) of the [Northwest Power Act) allow a utility the flexibility to determine whether resources will be used to serve a utility's firm load, these sections do not permit âa BPA customer to circumvent BPA's obligations under the Regional Preference Act for the reasons described below.
> "Section 3(d) of the Regional Preference Act restricts BPA's ability to sell firm power to a utility to replace hydroelectric energy generated in the Pacific Northwest and disposed of outside the region which a utility could have kept available for its own needs in the region. Section 3(d) allows BPA to sell as replacement for such energy only surplus energy subject to cut-off on 60 days' notice.
>
> "BPA hasâ determined that Tacoma could have kept for its own use the hydroelecfric energy generated from Tacoma's share of the .proJects on the South Columbia Basin Irrigation District (SCBID) canals. * * *
>
> "A customer's ability to determine which resources would be used to serve its firm load pursuant to [S]ection 5(b) of the [Northwest Power Act] is limited by the requirements of [S]ection 3(d) of the Regional Preference Act as incorporated in [S]ection 9(c) of the [Northwest Power Act). Section 9(c) directs BPA, in making any determination of the amount of firm power BPA would sell Tacoma under its power sales contract, to exclude from a customer's entitlement to purchase firm power (1) hydroelectric generated energy excluded from a utility's firm power requirements pursuant to [S]ection 3(d) of the Regional Preference Act and (2) electric energy from other resources a utility determines will be used to serve its firm load pursuant to [S)ection 5(b) which is sold by the

utility outside the region and which increases a utility's firm energy requirements as a result of such sale. * * *

"BPA's obligations under [S]ection 9(d) of the Regional Preference Act and [S]ection 9(c) of the (Northwest Power Act] to exclude from a customer's entitlement to purchase firm power hydroelectric energy sold outside the Pacific Northwest are triggered irrespective of whether a sale of hydroelectric generated energy outside the region increases a utility's firm energy requirements on BPA as a result of the sale. Sales by BPA of firm power to replace hydroelectric generated energy sold outside the Pacific Northwest are precluded even if a utility had not elected to use such hydroelectric generated energy to serve its own firm loads."

3. Section 9(c) Policy Background.
The proposed Section 9(c) policy is intended to facilitate the export by New Owners of the following: (l) newer regional resources which have never been dedicated in any firm resource exhibit and (2) existing nonhydro regional resources which are not in any fir: resource exhibit and which have been offered for sale to BPA and the region but have not been acquired. The proposed Section 9(c) policy is not intended to encourage the export of regional resources' which are currently dedicated to serving firm loads in any utility's firm resource exhibit, particularty when BPA and some of BPA's utility customers are in load resource balance or deficit.

In order to be responsive to the New Owners' need for a Section 9(c) policy determination by Spring 1993, BPA intends to limit the application of this proposed Section 9(c) policy determination (based on BPA's supporting factual analysis) to those proposed exports by New Owners who have obtained or may obtain a share of the Intertie. These Section 9(c) determinations need to be made so that New Owners will know whether BPA intends to decrement their Section 5(b) utility power sales contract.

The following are the major components of the proposed Section 9(c) policy:

(a) BPA will complete its analysis regarding the probability of any increase in BPA's or its customers' energy obligations as a result of an export by a New Owner. BPA's analysis will review the following information: BPA's Whitebook data; customer load/resource information; customer resource stacks, and the least-cost plans of utilities who have stated in the past that they are not planning to place load on BPA;

(b) New Owners will be able to export up to a maximum of 725 MN of regional resources;

(c) The proposed 9(c) policy will be consistent with BPA's prior Northwest Power Act Section 9(c) determinations, e.g., letter to Tacoma City Light (SCBID) and letter to MPC;

(d> BPA will apply Its proposed Section 9(c) pol-Icy to the specific resources of New Owners based on the information provided of specific resources and on categories of resources for export;

(e) Newly developed thermal resources not in any firm resource exhibit will generally be allowed to be exported by a New Owner without any decrement of their Section 5(b) utility power sales contract;

(f) Exports of regional hydro resources and thermal resources in firm resource exhibits will result in a decrement of the New Owner's Section 5(b) utility power sales contract:

(g) Seasonal exchanges between the Pacific Northwest and Pacific Southwest which result in no net energy loss to the region on an annual basis will not result in a decrement by BPA of a New Owner's power sales contract because there should be no need to acquire replacement energy resources or make additional energy purchases in the Pacific Northwest to support an exchange;

(h) System sales will result in a reduction in BPA's firm load obligation to the exporting utility under its requirements contract with BPA. Such sales may involve the export of hydro resources,. conservable thermal resources in a firm resource exhibit, or the indirect resale of Federal power and energy (inconsistent with the utility power sales contract Exhibit A, General Contract Provisions; Section 9(c) of the Northwest Power Act; and Sections 2 and 3 of the Regional Preference Act);

(i) A New Owner that does not want BPA to decrement its export if SPA would otherwise do so will have the option to include recall terms in its export sale which provide that the utility would discontinue its export sale, on notice from BPA that the resource will be needed by a certain date to serve load in the Pacific Northwest; and

(J) A New Owner may decide to offer its resource to BPA and other Pacific

Northwest generating customers at the New Owner's cost plus a reasonable rate of return. If the resource is not purchased it generally may be exported without a decrement of the New Owner's Section 5(b) utility power sales contract.

4. Proposed Section 9(c) Policy.
Depending upon BPA's analysis of loads resources and proposed exports, the proposed Section 9(c) policy may be as follows:

Section 1.

As required by the Northwest Power Act, BPA will make its Section 9(c) determinations for the exports of New Owners using their share of Pacific Northwest-Pacific Southwest AC Intertie (Intertie).

Section 2. Finding Required

In examining the export of up to 725 MN of Northwest resources, BPA will make its finding based on the following requirements of Section 9(c):

(a) BPA will analyze whether the New Owners' exports would result in an increase in the electric power requirements of any of its customers in the region. BPA will do this by examining its load/resource forecasting and planning documents to determine the impact the exports will have on BPA's ability to meet Pacific Northwest load presently and in the future. BPA will also analyze the information available from other sources including least-cost plans and load/resource information of utilities which are not placing any loads on BPA currently, like investor-owned utilities.

(b) BPA will review the specific resources and categories of resources being exported to determine if such exports will result in additional firm load obligations on BPA and if so, determine whether the resource could be conserved or otherwise retained for service to regional loads by using reasonable means. To do this BPA will compare the resource a New Owner is proposing to export with those resources BPA finds in its analysis can be exported without having to decrement the New Owners' Section 5(b) utility power sales contract.

Section 3. Scope of Proposed Section 9(c) Policy

This proposed Section 9(c) policy addresses only the amount of anticipated exports (up to 725 MN) of Pacific Northwest resources by New Owners who obtain a share of the Intertie. As noted in section 2, BPA will make its Section 9(c) determinations based on a factual determination using information about the specific resource the New Owner intends to export. This proposed policy does not automatically decrement New Owners for any resource when they wheel for others and in which the New Owner has no ownership or contractual interest.

Section 4. Data on Specific Resources

BPA will base its Section 9(c) determination on specific âinformation SPA has obtained from New Owners on the resources they intend to export. This includes the following information:

(a) name of the resource to be exported,

(b) location of the resource,
(c) type of resource,
(d) whether the resource is currently in any Pacific Northwest utility's firm resource exhibit,
(e) whether the resource is planned or existing,
(f) type of transaction or sale, and if it is a seasonal exchange, the terms of the exchange.

BPA wilâl also consider any prior history of the resource Including prior efforts to market it to BPA or other Pacific Northwest utilities.

Section 5.

BPA does not propose to modify its existing determinations on Pacific Northwest utility exports and will apply its prior case-by-case interpretations of Section 9(c), and Section 3(d) of the Regional Preference Act without modification.

Section 6. Categories of Resources

(a) Exports That Will Not be Determined by BPA. Under this proposed Section 9(c) policy determination, BPA would determine that the export of certain resources are not likely to result in an increase in the electric power requirements of any of its customers under its Section 5(b) contracts and thus may be exported without a reduction in BPA's firm load obligation

under the New Owner's Section 5(b) power sales contract. Those resources which are of a similar type will be treated the same for purposes of this determination, i .e., all new cogeneration resources proposed for export will be treated the same. Those resources which, based on BPA's present information, may not result in any increase in electric power requirements include the export of:

Existing or planned cogeneration, renewable (nonhydro) or thermal resources exported by a New Owner, that are currently not dedicated in any Pacific Northwest utility's firm resource exhibit.

(b) Exports That Will be Decremented by BPA. BPA has determined based on its prior policy interpretations of Northwest Power Act Section 9(c) that the following categories of resources are conservable and if they are exported BPA will decrement the New Owner's Section 5(b) power sales contract:

(1) all Section 5(b)(1)(A) and 5(b)(1)(B) Pacific Northwest hydroelectric resources owned or purchased by a Pacific Northwest utility, whether or not dedicated in any Pacific Northwest utility's firm resource exhibit;

(2) all Section 5(b)(1)(A) and 5(b)(1)(B) thermal resources that are currently dedicated by a utility in any firm resource exhibit.

Section 7. System Sales

BPA will decrement the Section 5(b) power sales contract of any New Owner engaged in a system sale from the effective date of the export, in the energy amount and for the duration of the system sale. Any New Owner that is a Contracted Requirements customer of BPA and which is currently purchasing power and energy from BPA under its power sales contract will have SPA's firm energy obligation under its power sales contract reduced in the amount of energy of the export sale. If the New Owner is not currently placing load on

BPA under ts Section 5(b) utility power sales contract, then at such time as the New Owner requests to place a firm load obligation on BPA, SPA will make an appropriate determination and may reduce its energy sales to such New Owner in the amount of the export sale and for any remaining duration of the export sale.

Section 8. Seasonal Exchange

Any seasonal exchange between a New Owner and a Pacific Southwest utility which results in no net regional energy deficit during any Operating Year, will not result in a decrement by BPA of the New Owner's Section 5(b) utility power sales contract.

Section 9. Recall

Any New Owner that does not want its Northwest Power Act, Section 5(b) power sales contract decremented by BPA may agree to include terms for the recall of its export sale upon notice from BPA that the energy from such New Owner's resource is needed to meet requirements load in the Pacific Northwest.

Section 10. Resource Offer

This proposed Section 9(c) policy gives a New Owner an option to offer a resource to BPA or to all other Pacific Northwest generating utilities. If offered for sale to BPA, the resource will be treated as an unsolicited proposal. If it is over SO MN it will be subject to the Northwest Power Act Section 6(c) process, which can take up to 12 months or more. If neither BPA nor any Pacific Northwest utility purchases the offered resource (offered at the New Owner's cost plus a reasonable rate of return) the resource may then be exported without a decrement of the New Owner's Northwest Power Act Section 5(b) power sales contract.

Section 11. Consumer-Owned and Independent Power Producer-Owned Resources

If a New Owner contracts to purchase and then export any consumer-owned resource or any resource developed by an independent power producer, BPA will decrement the New Owner's Section 5(b) power sales contract if the resource being exported is a hydroelectric resource or is dedicated to any Pacific Northwest utility load in any utility's firm resource exhibit.

Section 12.

From the date BPA's Section 9(c) policy determination is final, SPA will notify in writing each New Owner with an allocated share of Intertie of the outcome of BPA's Section 9(c) determination: The SPA notification will be made within 3O working days from the -date the New Owner notifies BPA that It will be exporting a regional resource over its allocation share of Inâtertie.

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Appendix B Long-Term Intertle Access Policy

EXECUTIVE SUMMARY

LONG-TERM INTERTIE ACCESS POLICY

U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
MAY 17, 1988

INTRODUCTION

The Pacific Northwest-Pacific Southwest Intertie began operation in 1968. Congress authorized the construction of the Intertie to provide an additional market for surplus BPA power, thereby providing greater assurance that we would repay the U.S. Treasury for the Federal investments in the Northwest's power system. To the extent there was capacity excess to Federal needs, Congress also intended that the Intertie allow nonfederal utilities in the Northwest and California to take advantage of the diverse load patterns and resource types between the two regions.

The present capability of the Intertie is about 5,200 megawatts (NM). 3,200 NM on the two alternating-current (AC) lines and 2,000 NM on the direct-current (DC) line. Ownership of the Intertie in the Northwest is shared by BPA, Portland General œlectriâc Company (PGE) and Pacific Power & Light Company (PP&L). Me provide access to all Northwest generating utilities. Ownership in California is shared by four investor-owned and municipal utilities.

In the early 1980s demand for sales over the Intertie increased dramatically: Nearly every utility in the Northwest had excess power to sell and forecasted a surplus into the next decade and beyond. Northwest utilities frequently filled the Intertie with nonfirm energy and sought to negotiate long-term transactions with California. Prior to 1984 and the implementation of the Interim Intertie Access Policy (IAP), BPA lost significant revenue opportunities by allowing other utilities unfettered access to the Intertie.

Combined effects of (l) the Northwest Preference Act, 16 U.S.C. .837, et seq.,
which gives Northwest utilities a special competitive advantage over us; (2) oversupply conditions in the Northwest; and (3) a restricted market in California due to limited ownership of the Intertie in California caused us to
lose sales. We were unable to make our payments to the U.S. Treasury.

In 1984 we implemented the Interim lAP. followed by the Near-Term lAP in 1985. These policies governed access to the Intertie while we developed a Long-Term Intertie Access Policy (LTIAP).

The LTIAP, issued by the Administrator on Nay 17, 1988, accomplishes the following objectives which have guided us throughout the process:

1. The LTIAP assures 8PA of reasonable access to the Intertie to sell both firm and nonfirm energy, thereby enhancing our ability to repay, with interest, $8 billion in Treasury investments.
2. The policy is a reasonable and effective means of safeguarding our $120 million investment in fish and wildlife protection.
3. It balances the competing demands of nonfederal utilities for Intertie access to sell, exchange, or purchase both firm power (through long-term contracts) and nonfirm energy (through the short-term, spot-market).
4. It provides a basis for greater planning certainty to utilities.
5. It allows for efficient use of generating resources in the Northwest and California.
6. It specifically addresses competitive concerns between California and the Northwest.
7. In doing all of the above, it strikes a balance between the Northwest and California, among generating and nongenerating utilities, other BPA customers, environmental interests and Federal taxpayers.

Issuance of this policy culminates our review of comments submitted by over 150 different utilities, regulatory agencies and interest groups. Through a combination of formal, transcribed meetings and informal discussions, we have increased our knowledge of their positions -- and they of
ours. Me have twice appeared before the U.S. House Subcommittee on Mater and Power Resources to answer questions regarding the IAP. Though often cumbersome and lengthy, the process has produced a policy which addresses the demands of all parties.

balancing Interests. Me have been put in the difficult position of balancing the competing interests for use of the Intertie. The sum of the demands placed on the Intertie far exceeds the facility's ability to meet them.

Our total-requirements customers insist that BPA should protect its revenues in order to maintain stable power rates and to repay the U.S. Treasury in a timely manner. They suggest that BPA should allocate firm and nonfirm Intertie access to itself first, always assuring that BPA would be able to sell its surplus power. Northwest generating utilities seek a policy which allows sufficient and assured access for their own firm and nonfirm sales. California parties generally argue for a policy which allows them unconstrained access to inexpensive Northwest and Canadian resources. Environmental organizations support a policy that would prevent the Intertie from encouraging development that would harm fish and wildlife resources.

Our main concern in reaching this balanced policy has been reconciling BPA's need to meet its fiscal obligations with these other competing demands for use of the Intertie. While BPA has the discretion to implement the "Federal-first" policy supported by our full requirements customers, the LTIAP instead provides significant access to nonfederal utilities for a variety of transactions while protecting BPA from revenue shortfalls.

It is not reasonable to suggest, as California commenters did in the public process, that BPA incur revenue losses to be recovered through rate increases to its total-requirements customers. These customers have a strong statutory argument explained in the decision -- that we should adopt a Federal-first policy to maximize Federal sales over the Intertie. By rejecting Federal-first, we incur an obligation to provide these customers with rate stability through alternative means- First among these alternative protections is the reservation of Intertie capacity for BPA sales.

If the revenue-protective measures adopted in the LTIAP prove unworkable or unduly controversial, the obvious remedy is not more access for nonfederal utilities. Instead, it is Federal-first.

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FORMULA ALLOCATION

The Intertie accomodates transactions in two distinct markets. Sellers oF power to California sell in two distinct markets, - one for long-term transactions and one for short-term sales. Formula Allocation in the LTIAP refers to Intertie capacity made available for short-term sales of energy. Ne have taken a hard look at Formula Allocations as it has been one of the most hotly debated issues throughout the LTIAP's development.

The LTIAP continues the basic Formula Allocation method used in the Near Term Intertie Access Policy (NTIAP) of allocating access to the Intertie based on three possible conditions. Me have changed the specifics of each Condition to reflect criticisms and suggestions made on the two LTIAP drafts. Provisions for Conditions 2 and 3 address directly the contentious anti-competitive concerns between California and the Northwest.

Condition 1. Condition 1 under the NTIAP incorporated the pre-existing Exportable Agreement, which expires on December 31, 1988. Parties to the agreement declare amounts of surplus energy available for export at the applicable BPA rate. If total declarations of exportable energy exceed the available Intertie Capacity or the size of the Pacific Southwest market, whichever is smaller, each party to the agreement is allocated access to the smaller amount based on its share of total declarations.

The 1986 draft LTIAP proposed -that upon expiration of the Exportable Agreement a condition of spill or likelihood of spill on the Federal Columbia River Power System (FCRPS) would trigger Condition l. BPA and Northwest Scheduling Utilities could declare surplus energy available for export and BPA would allocate access to the Intertie based on the ratio of each declaration to the sum of all declarations multiplied by the available Intertie Capacity. Each Scheduling Utility's allocation would be limited by the ratio of its regional hydroelectric capacity to the total regional hydroelectric capacity

of the Scheduling Utilities multiplied by the total of all declarations (the "Hydro Cap").

We received comments on the 1986 draft which led us to revise Condition 1 to mirror the Exportable Agreement more closely. Under the 1987 draft a condition of spill or likelihood of spill on the FCRPS determined Condi-tion 1. BPA and Scheduling Utilities could declare surplus energy available for export at the applicable BPA rate and receive a share of available Intertie Capacity based on the- Hydro Cap. To the extent that the market for Northwest energy at BPA's price was less than the available Intertie Capacity, we allocated access to the Intertie to equal that market.

Generally, commenters on the 1987 draft did not argue against Condition per se. They focused instead on its specific provisions. The bulk of the comments were directed at the Hydro Cap and at allocating Intertie capacity based on the size of the California market rather than the size of the âIntertie capacity. In response to concerns heard at the public meetings in January 1988, we proposed an alternative Condition l allocation method. The LTIAP adopts this recent proposal.

The True-Up. The market for power in California is often less than the available Intertie capacity because of minimum generation requirements in California. As the Intertie is expanded and Southwest utilities bring on new generation that cannot be displaced with spot-market purchases, the frequency of this situation is likely to grow.

The 1987 draft allocated Intertie capacity based on the size of the California market as a protection against revenue shortfalls. Analyses indicated that we would lose approximately $16.4 million in 1989 by allocating to the Intertie rather than the market. This loss would decrease to $10.7 million in fiscal year 1992. Seyond 1992 the difference would increase, mainly due to projected fuel price increases.

The heart of the revenue problem is the Northwest Regional Preference Act, 16 U.S.C. 837, et seq.â which requires 8PA to quote an energy price to Northwest utilities before making any sale to the Southwest. This creates a problem in which Northwest utilities, which are BPA's competitors know our price -- but we do not know their prices. In Condition 1, where the size of the Southwest market is less than available Intertie Capacity, Northwest utilities are able to use this information to undercut the BPA price and use their allocations to reduce BPA's hourly sales to a small Southwest market. If a "real-time" BPA pricing iteration were even possible, we would still be required to announce our new price to the Northwest. Regional preference makes BPA a "sitting duck" for its competitors.

Allocating according to the California market size would reduce BPA's vulnerability by reducing the size of Scheduling Utility allocations. This provision came under attack, however, from both California and Northwest parties. The alternative discussed at the January 27 public meeting seemed to allay concerns regarding 8PA's market control. No one disputes that the Regional Preference Act causes BPA a revenue dilemma, especially at times when we face spill on the hydro system. The true-up alternative is the least Intrusive remedy.

The Hydro Cap. Both the 1986 and 1987 LTIAP drafts allocated Intertie capacity based on a utility's hydroelectric capability. The logic for the Hydro Cap was that when the Federal system is spilling or likely to spill, the maximum allocation to utilities with greater hydroelectric resources would increase, thus decreasing the probability of wasting the resources by spilling. Under this provision, BPA's share of allocations would tend to increase due to its large hydroelectric capacity.

Much of the debate over the Hydro Cap focused on two issues. First, removing the Hydro Cap could cause hydro-based utilities to spill. Second,

without the Nydro Cap. utilities could "overdeclare" by including uneconomic combustion turbines in their declarations with no intent of ever operating them.

Discussion at the January meetings helped resolve these concerns. Nhen the Federal hydro system faces spill. other systems might not always be in the same condition. The Hydro Cap could give disproportionately large shares of Intertie Capacity to hydro-based utilities when they may not face a threat of spill. while frustrating the marketing activities of utilities with hydro and thermal resources. Furthermore. several utilities and 8PA indicated that if a utility is facing spill with insufficient access to market the available energy on the Intertie. such energy could generally displace Northwest thermal generation.

Several factors would help deter overdeclarations. First, the take-or-pay feature of our 15-87 transmission rate requires a utility to pay for its allocation whether or not it is used. Second. 8PA monitors declarations and is aware of each utility's resources and capabilities. Me have not observed significant overdeclarations under past policies. Third, from time to time we can request documentation on each utility's declaration as a further insurance against abuse.

Condition 2 and 3. Allegations of anti-competitive practices on both the northern and southern portions of the Intertie were made during the debate over Formula Allocations. California commenters argue that pro-rata allocations to nonfederal utilities under the LTIAP would tend to stabilize prices at levels higher -than those at which sellers might increase their total sales by reducing prices. The Northwest just as logically concludes that pro-rata allocations of California Intertie capacity suppress prices below levels that would prevail in a market where more buyers independently bid for Northwest energy.

We recognized that in implementing a long-term policy we must try to resolve this issue to meet the goals outlined for the LTIAP. We therefore proposed in section 5(d) of the 1987 draft LTIAP to ceaseâpro-rata allocations
to non-Federal utilities under Conditions 2 and 3 after completion of the third AC Intertie, provided anti-competitive problems in the Southwest were cured by that time. This proposal was discussed extensively during the public meetings in January 1988 and again in comment letters, mainly from California parties. The final LTIAP takes this proposal a step further. Section 5(d) now ceases pro-rata allocations under Conditions 2 and 3 for an 18-month experimental period.

Me will analyze the success or failure of the experiment throughout its term. We will be particularly concerned about the removal of restrictions on California's portion of the Intertie. Utilities, regulators, and other interested parties will be encouraged to express their views in writing and through -informal discussions. At least 30 days before the experiment ends, we
will issue a written report on whether to continue the experiment.

The experiment will work as follows. Under Condition 2, when the declarations of BPA and Northwest utilities exceed Intertie capacity, we will make a pro-rata allocation to BPA and leave the remaining block of Intertie capacity available to Northwest utilities as a whole. Each Northwest utility could then compete to make sales to Southwest utilities, with no assurance of any individual allocation. Under Condition 3, when the declarations of BPA and Northwest utilities are less than Intertie capacity, we will again make a pro-rata allocation to BPA and a block allocation to Northwest utilities. After regional utilities, U.S. extraregional utilities and then Canada have access to remaining Intertie capacity. During Condition 3, we expect significant competition whenever the size of the California market is less than Intertle capacity.

Until the experiment is in effect, Conditions 2 and 3 are similar to those
in the NTIAP and the two LTIAP drafts.

The LTIAP retains pro-rata allocations under Condition 1. Allocation under Condition l appears to be of less concern to California commenters than allocation during other conditions. Alternative Formula Allocation proposals recognized the importance of pro-rata allocations when the Northwest faces spill conditions. Retention of Condition 1 allocations will (1) help assure nonfederal utilities of Intertie access when hydrological conditions might otherwise force them to spill, and (2) provide an enforcement mechanism for the Protected Area provisions described below.

Some commenters have suggested that we allow access to Canadian utilities equal to that of Northwest utilities. The courts, however, have upheld our policy that capacity excess to our needs must be provided on a fair and nondiscriminatory basis first to Northwest utilities. If the Free Trade Agreement between Canada and the United States now being considered in Congress and the Canadian parliament is implemented, the distinction between U.S. extraregional utilities and Canadian utilities will no longer be made.

ASSURED DELIVERY

Utilities seek firm access to the Intertie for long-term transactions. The LTIAP refers to this kind of access as Assured Delivery. The earlier NTIAP did not provide for Assured Delivery service.

Amount. The final LTIAP reserves 800 MN for Assured Delivery transactions. This is an increase from the 420 MN reserved in the 1986 draft. BPA lost $213 million in fiscal year 1987; we do not want to exacerbate this problem with the final LTIAP. Given these uncertainties, we are cautious about committing major portions of the Intertie for long-term nonfederal use.

Yet. the 800 NM upper limit in itself is a fairly dramatic departure from the past. It will facilitate a greater number and variety of firm transactions than before. Our studies indicate an annual revenue loss of approximately $9 million in lost nonfirm revenue and displaced firm power sales to our public agency customers. The revenue effects on 8PA have been quantified further in a study by the PNUCC. These adverse revenue effects, offset by mitigation measures discussed below, have been found acceptable by a fairly broad cross-section of commenters.

In the public meeting and comment letters. most parties seemed satisfied with the 800 NM if we were to consider increasing it upon completion of the third AC project. 8PA will reassess the 800 NM limit upon commercial operation or termination of the project.

Exhibit B Allocations. As for the limits on types of transactions, BPA is convinced of the wisdom of imposing limitations on firm power sales. These limits are shown in Exhibit 8 of the LTIAP. From the standpoints of environmental quality and financial risks, it seems appropriate to limit Assured Delivery capacity to the amount of firm surplus presently available in the Northwest for export sales. In a change from the 1987 draft policy, the

LTIAP provides that Scheduling Utilities may use their Individual Exhibit B amounts for sales or exchanges.

The final LTIAP does not allocate the remaining 356 MN of Assured Delivery capacity among Scheduling Utilities. That amount will be available for exchange transactions of Scheduling Utilities on a first-come, first-served basis.

We have reached agreement (or agreement in principle) covering 341 NM of

Assured Delivery service. Agreements include a 20-year 105 MN firm power sale from Montana Power Company to Los Angeles Department of Water and Power; a 41 NM firm power sale from Tacoma City Light to Western Area Power Administration (MAPA); a 45 NM firm power sale from Longview Fibre/Cowlitz County Public Utility District to MAPA; and a 20-year 150 NM seasonal exchange between The Washington Mater Power Company and Pacific Gas and Electric Company. âœach of these agreements accommodates our lost revenue concerns differently.

To allow for maximum use of the Intertie, a utility granted Assured Delivery may shape its firm power sale into the months of September through December by delivering up to 1.8 times its Exhibit 8 amount. During those fall months, spot market energy sales to the Southwest tend to be less than in the spring when the region's hydroelectric dams are more often near or in a spilling condition. If a utility shapes Assured Delivery energy into the fall, less fir: energy may be shaped into remaining months of the operating year so that the total energy delivered does not exceed its annual Exhibit 8 energy maximum for firm sales.

BPA will also continue to work with Nonscheduling Utilities to provide the opportunity to sell the output of their generating resources over BPA's Intertie capacity.

Mitigation. Mitigation refers to conditions Imposed on a utility for an Assured Delivery contract. Intertie Capacity not available to BPA because of Assured Delivery contracts executed between a Northwest utility and a Southwest utility can reduce 8PA revenues and inhibit BPA's ability to make its Treasury payments. During the operating year BPA often has power available to fully load the Intertie. Assured Delivery granted under these circumstances would reduce 8PA's revenues, thereby putting at risk our ability to meet our obligations to the Treasury.

This fiscal concern is in potential conflict with the policy objective underlying the 800 KM of Assured Delivery -- assisting Northwest utilities in disposing of their surpluses by means of long-term firm power sales to the Southwest. Strong objection was received from our Priority Firm Power customers to our absorbing the entire cost (lost revenues) of these transactions and the subsequent passiâng of the costs to them in increased rates. California and Northwest generating utilities generally tend to agree that some form of mitigation is due BPA. They question the level of compensation and what provisions for mitigation should be included in the LTIAP.

The 1986 draft of the LTIAP allowed Assured Delivery without regard to the adverse impacts on BPA's ability to sell firm power or nonfirm energy. Both the 1987 draft and the LTIAP impose mitigation upon utilities with Assured Delivery contracts. The mitigation provisions in the LTIAP provide only partial compensation for the revenue impacts resulting from transactions, but provide sufficient assurance that these transactions over the Intertie will not harm our revenue recovery.

It would be a false precision to claim that we could develop mitigation measures that offset dollar-for-dollar the losses projected in any 20-year study. Assumptions about annual rainfall, gas prices, aluminum prices, and

load growth make this exercise judgmental. With this limitation In mind, the LTIAP incorporates the following mitigation provisions.

One mitigation measure requires that during any hour in which prescheduled energy sales are made under Condition 1 and Condition 2 Formula Allocation procedures, a utility must deduct its Assured Delivery amount from its Formula Allocation amount. The total amount of Intertie access granted to each utility is equal to its Formula Allocation. If a utility's Assured Delivery amount is greater than its Formula Allocation, then that utility must purchase enough energy from BPA or, during Condition 1, other Northwest utilities to make' up the difference. This mitigation measure will - partially offset the spot-market revenues 0PA will lose by granting Assured Delivery.

Under the other mitigation measure, if 8PA has invoked Condition l or Condition 2 Formula Allocations: cash out provisions of exchange contracts become inoperative. Cash outs allow a Northwest utility to accept dollar payments from a Southwest utility in lieu of actual energy returns. Prohibiting these during Conditions l and 2 has the effect of increasing the north-to-south capability of the Intertie when energy is being returned and increasing the size of the market for BPA and Scheduling Utility sales.

The draft LTIAP required energy returns under seasonal exchanges to the California/Oregon border (COB) or the Nevada/Oregon border (NOB). This was initially included in the mitigation provisions for seasonal exchanges. However, BPA needs the certainty of available capacity resulting from return requirements at COB/NOB. For this reason, the final LTIAP includes this provision as a standard requirement for all exchanges rather than considering it a mitigation measure.

The LTIAP also allows utilities the opportunity to negotiate individual packages of mitigation in addition to the LTIAP's stated mitigation provisions. Such case-by-case mitigation packages could be a combination of

the above mitigation provisions or could include beneficial arrangements for 8PA that have not been addressed in this policy. Our main concern in any mitigation package is recovery of any spot-market revenue losses, but we will also be looking at the operational impacts of any proposal.

Extraregional Access, Provisions in the 1987 draft for firm transactions by extraregional utilities required that the utility must provide some benefit to BPA, such as increased storage, improved system coordination or operation, or other consideration of value. In addition, the utility must agree to the mitigation provisions of the policy. Canadian utilities were required to wait for access until after the Intertie was rated at 7900 NM.

In reconsidering this provision we saw no reason for denying Canadian utilities access for firm transactions until after the Intertie is upgraded to

7900 MW if Canadian utilities are willing to provide increased coordination or
other items of value. This provision of limiting Canadian access to after an upgrade of the Intertie has been deleted from the LTIAP.

âAs with Formula Allocation, BPA anticipates that if the Free Trade Agreement is passed the distinction between U.S. extraregional utilities and Canadian utilities will no longer exist.

FISH AND WILDLIFE PROTECTION

Protected Areas. The LTIAP prohibits Intertie access for new hydro projects licensed within "protected areas" -- river reaches withdrawn from hydro development due to the presence of wildlife or anadromous and high-value
resident fish. BPA also has designated areas where we have determined that investments in habitat, hatchery, passage, or other projects may result in the
presence of anadromous fish. The Northwest Power Planning Council (Council) has proposed a protected area program that covers the entire Northwest. BPA's designations, however, cover only the Columbia River basin.

Our focus Is on hydro developments which will frustrate our investments made In the region to achieve the goals of the Council's Fish and Wildlife Program. The LTIAP ensures that those expenditures and existing productive habitat will not be harmed by future hydro developments. BPA has designated protected areas by using Information collected through the Council's Nydro Assessment Study.

Under the LTIAP, we will consider the Council's final protected area program or any revisions the Council may Include In the future. We will also consider appropriate state comprehensive river plans. The policy should effectively eliminate utilities' fears that they never know with certainty whether a hydro resource will qualify, or continue to qualify, for access to the Intertie.

The LTIAP does not necessarily prevent hydro development in protected areas. However, the protected area provisions will send an unambiguous, self-enforcing message to FERC, other regulators, and hydro developers that no
Intertie access will be provided for projects constructed in areas of greatest
concern to BPA and the Council.

Enforcement. If a Scheduling Utility proceeds to acquire a license or purchase power from a hydro project developed In a protected area, BPA will

reduce the amount of that uti Ii ty's power transmitted over the Intertie during
Condition 1. Depending upon the size of the project, the reduction may affect both Assured Delivery and Formula Allocations. These reductions will take

place regardless of whether power from the protected area project is actually transmitted on the Intertie. There is no need to trace power flows from a protected area resource.

Projects at affected by the Policy. For all hydro projects not affected by - BPA's protected area designations, 8PA will intervene in FERC -proceedings if we determine that projects -- new or existing, inside or outside the Columbia Basin -- pose significant threats to our fish and wildlife responsibilities.

The provisions do not affect hydro projects licensed before the effective date of the policy. While we recognize a potential for existing projects to harm 8PA fish and wildlife investments, we do not believe there is sufficient evidence to indicate that those projects are presently operating contrary to the Council's Fish and Wildlife Program or that the Council has been unable or
unwilling to implement Program measures through the FERC process. Keasures affecting existing projects in the Council's Program are explicitly directed to FERC and state agencies for implementation.

We have provided a limited procedure to provide access to the Intertie in the case of a project a developer believes will contribute to the Council's Fish and Wildlife Program and 8PA investments. However, our decision to provide access relies on a clear demonstration of the benefits and a regional consensus.

Finally, the LTIAP creates a limited exception for Protected Area projects
that an investor-owned utility might be forced to acquire under PURPA. To qualify, however, the affected utility must pursue all legal remedies available to avoid purchasing the Protected Area project output.

#LONG-TERM INTERTIE ACCESS POLICY

GOVERNING TRANSACTIONS OVER FEDERALLY OWNED
PORTIONS OF THE
PACIFIC NORTHWEST-PACIFIC SOUTHWEST INTERTIE

U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
MAY 17, 1988

FINAL LONG-TERM INTERTIE ACCESS POLICY

Section 1. Definitions

1. "Administrator" means the Administrator of Bonneville Power Administration (8PA) and is used interchangeably with BPA.

2. "Administrator's Power Marketing Program" refers to all marketing actions taken and policies developed to fulfill 8PA's statutory obligations. These actions and policies are based on exercises of authority to act, consistent with sound business principles, to recover revenue adequate to amortize investments in the Federal Columbia River power and transmission systems, while encouraging diversified use of electric power at the lowest practical rates. In the Northwest, the Administrator's Power Marketing Program covers BPA's obligations to provide an adequate, reliable, economical,
efficient. and environmentally acceptable power supply, while preserving public preference to Federal power. In the Southwest, the Administrator's Power Marketing Program covers activities to market surplus Federal power at equitable prices. while preserving regional and public preference to Federal power. and to assist in marketing Northwest nonfederal power.

3. "Allocation" means the share of the Intertie Capacity made available
for short-term sales of energy.

4. "Assured Delivery" means.firm transmission service provided by BPA under a transmission contract to wheel power covered by a contract between a Scheduling Utility and -a Southwest utility. Assured Delivery contracts may not exceed 20 years in duration. The service is interruptible only in the event of an uncontrollable force or a determination made pursuant to sections 7 or & of this policy.

5. "Available Intertie Capacity" is defined as the physically available
capacity controlled by BPA, reduced by the capacity reserved under Section 2 of this policy, and the capacity necessary to satisfy Assured Delivery contracts not subject to operational mitigation requirements under this policy.

6. "BPA Resources" means Federal Columbia River Power System hydroelectric projects; resources acquired by BPA under long-term contracts: and resources acquired pursuant to section 11(b)(6)(i) of the Federal Columbia
River Transmission System Act.

7. "Exchange" refers to various types of transactions that take advantage of diversity between Northwest and Southwest loads through deliveries of firm power, at prespecified delivery rates. from North to South during the Southwest's peak demands and returns of capacity and/or energy from
South to North during other times. Transactions vary depending-on the lag between deliveries and returns. A "naked capacity' transaction might require off-peak energy returns within 24 hours, whereas a seasonal exchange might call for firm power returns within 6 months.

8. "Extraregional Utilities" are generating utilities. or divisions thereof, that do not provide retail electric service and do not own or operate

significant amounts of generating capacity in the Northwest.

9. "Formula Allocation" means the process by which Intertie Capacity made available For short-term sales of energy.

10. "Intertie" means the two 5OO-kv alternating current (AC) transmission lines and one 1000 kv direct current (DC) line, which extend From Oregon into California or Nevada, and any additions thereto identified by 8PA as Pacific Northwest-Pacific Southwest Intertie facilities.

11. "Intertie Capacity" means the North to South transmission capacity of the Intertie controlled by BPA through ownership or contract: increased by power scheduled South to North, decreased by loop flow, outages, and other factors that reduce transmission capacity: and further decreased by Pacific Power & Light Company's schedules, under its scheduling rights at the Malin substation (BPA Contract Nos. DE-MS79-868P92299 and DE-M579-798P90091).

12. "Mitigation" refers to the requirements imposed by BPA on a utility in return for an Assured Delivery contract. Mitigation helps offset operational and economic problems, attributable to a Scheduling Utility's firm power transaction that inhibit BPA's ability to generate revenues. The Mitigation measures specified in this policy must be included in all Assured Delivery contracts, unless a scheduling utility either agrees to a specially designed charge or negotiates substitute measures with BPA on a case-by-case basis.

13. "Nonscheduling Utility" means a nonfederal Northwest utility that owns a Qualified Northwest Resource9 but does not operate a generation control area within the Pacific Northwest. A Nonscheduling Utility requesting Intertie access for Its resource must do so through the Scheduling Utility (or -BPA) in whose control area the resource is located.

14, "Pacific Northwest" (or "Northwest") is defined in the Northwest Power Act. 16 U.S.C. .839e, as the states of Oregon, Washington, and Idaho: the portion of Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming within the Columbia River drainage basin: and any contiguous service territories of rural electric cooperatives serving inside and outside the Pacific Northwest, not more than 75 air miles from the areas referred to above, that were served by BPA as of December 1, 1980.

15. "Protected Area" means a stream reach within the Columbia River drainage basin specially protected from hydroelectric development because of the presence of anadromous or high value resident fish, or wildlife. Protected areas may a-I so include stream reaches which could support anadromous fish if investments were made in habitat, hatcheries, passage, or other projects.

16. "Qualified Extraregional Resource" means:

(a) a generating unit located outside the Northwest that was in commercial operation on the effective date of this policy. However, the term excludes portions of units covered as Qualified Northwest Resources.

(b) after BPA has determined that the capacity of the Intertie is rated at approximately 7,900 KM, all resources located outside of me Northwest, other than the portions of extraregional resources covered as Qualified Northwest Resources.

17 "Qualified Northwest Resource" excludes BPA Resources, but includes:

(a) Resources located inside the Northwest that are in commercial operation as of the effective date of this policy.

(b) Scheduling Utility extraregional generating resources dedicated to Northwest loads on the effective date of this policy. This term includes pro rata portions of Montana Power Company's and Pacific Power and Light Company's shares of the Colstrip No. 4 generating station, based on the ratio of thei-r respective regional loads to their respective total loads: and Idaho Power Company's share of Valmy No. 2.

(c) New regional resources of Scheduling Utilities, except for hydroelectric resources located in Protected Areas.

18. "Resource" means an electric generating unit or stack of particular electric generating units identified to supply power or capacity for sale over the Intertie.

19. "Scheduling Utility" means the Northwest portion of a nonfederal utility that operates a generation control area within the Northwest, or any utility designated as a BPA "computed requirements customer." The term excludes Utah Power & Light Company, either as a separately owned company or as a division of another corporation. which has sufficient transmission capacity to the Southwest without access to the Federal Intertie.

20. "Seasonal Exchange" means a transaction that takes advantage of seasonal diversity between Northwest and Southwest loads through transfers of firm power, at a prespecified delivery rate, from North to South during the Southwest's summer load season and from South to North during the Northwest's winter load season. Seasonal Exchanges may involve payments of additional consideration to reflect the relative seasonal values of power throughout the western United States. Seasonal Exchange schedules of Northwest utilities will be referred to as `deliveries,' and schedules of Southwest utilities will be referenced as "returns.14 A Scheduling Utility must be able to support its summertime firm power deliveries with generating resources that are surplus to its Northwest requirements. The sum of a Scheduling Utility's energy

resources for each month in which deliveries are made (with special concern for August) must exceed its corresponding Northwest loads by an amount sufficient to support the Seasonal Exchange.

21. "Section 9(i)(3) resource" means a Scheduling Utility resource that 8PA has granted priority in receiving BPA transmission. storage and load factoring services as defined in .9(i)(3) of the Northwest Power Act.

Section 2. Intertie Capacity Reserved for BPA

The Administrator reserves for BPA's use Intertie Capacity sufficient to:

(a) transmit all of 8PA's surplus firm power and to serve other obligations.

(b) perform obligations, including, but not limited to, the existing transmission contracts listed in Exhibit C, to the extent such obligations differ from the conditions specified in this policy,

(c) provide Assured Delivery service for transactions not subject to limits under Exhibit S to this policy, and

(d) satisfy BPA firm obligations, that have not been prescheduled, by using unutilized portions of Formula Allocation amounts.

Section 3. Conditions For Intertie Access

(a) All Inrertie access will be granted pursuant to the conditions and procedures of this policy, unless otherwise specified in the three existing BPA transmission contracts listed in Exhibit A.

(b) BPA will provide Intertie access only for SPA Resources and the Qualified Northwest Resources of Scheduling Utilities, except to the extent that Qualified Extraregional Resources are permitted access under this policy.

(c) BPA will provide Assured Delivery and allocate remaining Intertie Capacity when providing such access will not substantially interfere with operating limitations of the Federal system. Examples of these limitations, which reflect BPA's obligation to operate in an economical and reliable manner
consistent with prudent utility practices, include:

(1) The BPA Reliability Criteria and Standards,
(2) Western Systems Coordinating Council minimum operating reliability criteria,
(3) North American Electric Reliability Council Operating Committee minimum criteria for operating reliability, and
(4) coordination agreements among BPA, scheduling utilities and - other Federal agencies regarding resource and river operations.

(d) Any utility tâhat has contractual or ownership rights to Pacific Northwest-Pacific Southwest Intertie capacity or to other transmission lines to California or the Southwest market must fully utilize such capacity prior to receiving any access to BPA's Intertie Capacity. If a Scheduling Utility with Intertie rights needs BPA Intertie Capacity to reach a particular Southwest utility, BPA will consider negotiated swaps of capacity to accommodate such requests.

Section 4. Assured Delivery for Intertle Access

Subject to the limitations and other conditions in this section and in other sections of this policy, BPA has determined that it can provide limited Assured Delivery to Scheduling Utilities without causing substantial interference with the Administrator's Power Marketing Program.

(a) General Provisions

(1) Disting Transmission contracts. BPA will provide Assured Delivery for the remaining terms of the firm power sale and Seasonal Exchange contracts identified in Exhibit A, to this policy.

(2) Utilities Owning Or Controlling southwest Interconnections. Assured Delivery is intended primarily for Scheduling Utilities which lack interconnections with the Southwest. Except for transactions covered by section 4(b) of this policy. a utility with capacity on an intertie, through contract or ownership. must utilize all such capacity on a firm basis before receiving any Assured Delivery.

(3) iture Of Transactions. BPA will not provide Assured Delivery for transactions which a Scheduling Utility cannot demonstrate to be other than an advance arrangement to sell nonfirm energy.

(4) Waiver Of BPA Service Obligation.

(A) Hydroelectric Resources. Assured Delivery contracts that facilitate the export disposition of Northwest hydroelectric energy shall provide. under 16 U.S.C. .837b(d). for a reduction of BPA's power sale contract obligation the Northwest utility. for the period of the disposition, equal to the amount of energy for which Assured Delivery is provided

(B) Yhermml Resources. Assured Delivery contracts that facilitate the export disposition of Northwest thermal energy -shall provide. under 16 U.S.C. .B39f(c). for a reduction of BPAâs power sale contract obligation the Northwest utility. for the period of the disposition. equal to the amount of energy for which Assured Delivery is provided. Such reduction shall become effective at the time BPA determines that it has reached energy load/resource balance: or at a date as specified in the Assured Delivery contract.

(5) Exchange Contracts. Exchange contracts must specify that all return energy be scheduled to either the AC Intertie point of interconnection at the California-Oregon border ("COB") or the DC Intertie point of interconnection at the Nevada-Oregon border ("MOB"). Exchange contracts must also specify prescheduled determinations of hourly energy returns.

(6) Satisfying Requests For Assured Delivery. All relevant power contracts must be presented for review no later than the date on which a request for Assured Delivery is made.

(b) New Transactions~Not-Subject To Capacity Limits

(1) Joint Ventures. Joint ventures between BPA and utilities. such as firm displacement contracts, which allow BPA to increase its sales of surplus power qualify for Assured Delivery.

(2) Sales In Lieu of Exchanges. BPA may offer to satisfy Scheduling Utility demands for Seasonal Exchanges by selling them incremental amounts of surplus firm power during winter months. Upon committing to purchase such incremental firm power at negotiated prices that reflect BPA's

lost opportunities for summer sales, a Scheduling Utility will qualify for Assured De-livery (with mitigation) to wheel an equal amount of firm capacity and energy over the Intertie during summer months.

(3) Conditions. A Scheduling Utility may request at any time the Assured Delivery of transactions identified in sections 4(b)(l) and 4(b><2). Relevant contracts must be presented for review when Assured Delivery is requested. BPA will satisfy a request within 60 days after a Scheduling Utility has demonstrated satisfaction of the requirements of this policy.

(c) Transactions Subject To Capacity Limits Under This Policy

(1) Maximum Amounts Of Assured Delivery. BPA will provide 800 MW of Assured Delivery for firm power sales and Exchanges identified in this policy. BPA will reassess the amount of Assured Delivery capacity when the 3d AC Intertie project is either completed or abandoned. Moreover, the 800 MW amount may be subject to some reduction if the DC Terminal Expansion project is not completed on schedule.

(2) Exibit 8 amounts.

(A) Current maximum. Each Scheduling Utility's maximum Assured Delivery amount for firm sales equals its average firm energy surplus, shown âin Exhibit B to this policy. BPA will reserve capacity equal to each Scheduling Utility's Exhibit B allocation subject to section 4(c)(2)(D) below. Except for Kontana Power Company (MPC), Tacoma City Light, and Cowlitz

County Public Utility District, Exhibits represents projected Scheduling Utility surpluses for the 1988-89 operating year. In satisfaction of all obligations to KPC under Northwest Power Act section 9(i)(3), MPC's Exhibit B amount is set at 105 MW to facilitate long-term sales of firm power from its share of the Golstrip No. 4 coal-fired generating station. Exhibit B amounts for Tacoma and Cowlitz are increased to accommodate existing firm power transactions.

(B) Shaping. Firm power sales eligible for Assured Delivery may be shaped within the following ranges. During the months of September through December, a Scheduling Utility may deliver firm energy at a rate up to 1.8 times its Exhibit B average firm surplus amount. During the months of January through August, a Scheduling Utility may deliver firm energy at a rate no greater than 1.0 times its Exhibit B amount. However, total delivered energy may not exceed the Exhibit B annual firm energy maximum.

(C) Other uses of inhibit 8 amounts. BPA will not entertain Assured Delivery requests for fir: power sales in excess of a utility's Exhibit B maximum. However, a Scheduling Utility may use any portion of its Exhibit B maximum, not used for firm power sales, for exchange transactions supported by Qualified Northwest Resources.

(D) Future Changes. BPA may, at its discretion, revise Exhibit B to reflect changes in the firm power surpluses of individual utilities; however, the Exhibit B average firm surplus total is not subject to increase. Any unutilized Assured Delivery amount will be revoked if, upon revision, a utility's individual Exhibit B amount has declined or if a utility has sold firm power `to another utility seeking to increase its Exhibit B

average firm surplus amount. A Scheduling Utility may increase its Individual Exhibit B amount by purchasing surplus firm power from BPA or any Scheduling Utility with an Exhibit B amount.

(3) Other Capacity. The remaining capacity available for Assured Delivery under this policy is offered to Scheduling Utilities, on a first-come, first-served basis, for Exchange transactions supported by Qualified Northwest Resources. When section 4(c)(2)(D) of this policy is implemented to reduce the Exhibit 8 maximum of any Scheduling Utility, the reduction will be added to the capacity made available under this provision. Any utility wi th an Exhibit 8 amount must exhaust such capacity before requesting Assured Delivery under this provision.

(d) Mitigation

(1) Operational Mitigation

(A) Southbound deliveries. During any hour in which BPA has invoked Condition 1 or Condition 2 allocation procedures to preschedule energy deliveries, each utility's Assured Delivery amount shall be deducted from its formula allocation to determine its share of energy scheduled on the

Intertie. If the remainder is negative for a given utility, then that utility must make up the difference by purchasing sufficient energy as follows

(i) during Condition 1 from BPA or any scheduling Utility with a Formula Allocation during that hour:

(ii) during Condition 2 from BPA, however, if BPA is not in the market the utility may purchase sufficient energy from any other utility.

(B) Northbound returns. During any hour in which BPA has invoked Condition l or Condition 2 allocation procedures, a utility may utilize the cash-out provisions of an Exchange contract only by reducing one-for-one the amount of North-to-South Intertie capacity other*ise available to it under this policy. The rate of cash out during any condition shall not exceed the rate at which the exchange return could have been scheduled.

(2) Negotiated Mitigation. A Scheduling Utility may also elect to negotiate with BPA on a case-by-case basis a package of mitigation measures involving mutually agreeable consideration of value commensurate with the service provided.

Section 5. Formula Allocation

(a) Limits On Intertie Capacity Available For Formula Allocation. Generally, BPA will determine Intertie Capacity available for Formula Allocations after first taking into account the amount of Intertie Capacity necessary to satisfy requirements of the Administrator's Power Marketing Program, existing transmission contracts listed in Exhibit C, and Assured Delivery contracts executed by BPA pursuant to this policy. However, In determining Available Intertie Capacity during Condition 1, BPA will not consider the Assured Delivery contracts to the extent they are subject to operational mitigation requirements. BPA may reduce any allocation. If additional Intertie Capacity is required to minimize revenue losses associated with actions taken to protect fish in the Columbia River drainage basin.

(b) Protected Area Decrements. Except as provided in section 4(d)(2)(A) of this policy, BPA will reduce each Scheduling Utility's allocation by any Protected Area decrement imposed pursuant to section 7(d).

(c) Allocation Methods.

(1) Condition 1

(A) Until December 31, 1988. Intertie Capacity will be allocated pursuant to the Exportable Agreement (BPA Contract No. 14-03-73155), when applicable.

(8) After December 31, 1988. Condition 1 will be in effect when the Federal hydro system is in spill or there is a likelihood of spill,

as determined by BPA. Available Intertie capacity will be allocated pursuant to the following procedure:

(i) Each hour, the maximum Condition 1 allocations for BPA and each Scheduling Utility will be based on the ratio of their respective declarations to total declarations, multiplied by the Available Intertie Capacity.

(ii) During Condition lâ whenever BPA is unable to utilize its full pro rata share of inter-tie usage BPA will take larger allocations on ensuing days until the difference in pro rata intertie usage is eliminated.

(2) Condition 2

(A) When Condition 1 is not in effect, but BPA and Scheduling Utilities declare amounts of energy that exceed available Intertie capacity, Formula Allocations for BPA and each Scheduling Utility will approximate, by hour, the ratio of each declaration to the sum of all declarations, multiplied by the available Intertie capacity.

(B) If BPA sales drop below 75 percent of its allocation during Condition 2, BPA may take larger allocations on ensuing days until the difference is eliminated.

(3) Condition 3

When Condition 1 is not in effect and when the total surplus energy declared available by BPA and Scheduling Utilities is less than the total available Intertie Capacity, BPA and Scheduling Utilities' allocations will equal their declarations. The remaining Intertie capacity will be made available first to U.S. Extraregional Utilities and then to other œxtraregional Utilities. Section 3(d) of this policy shall not apply to Scheduling Utilities during Condition 3.

(d) Formula Allocation Experiment. BPA is interested in exploring the proposal that it cease making individual Formula Allocations to Scheduling Utilities under Conditions 2 and 3. However, BPA must work with Northwest and Southwest utilities to develop the information capability to accommodate a new scheduling system for nonfederal access. As soon as this can be accomplished BPA will substitute the following provisions for section 5(c) on an 18-month experimental basis:

(1) Condition 1

Same as section 5(c)(l).

f

(2) Condition 2

(A) When Condition 1 is not in effect, but BPA and Scheduling Utilities declare amounts of energy that exceed available Intertie capacity, the Formula Allocation for BPA will approximate, by hour, the ratio of BPA's declaration to the sum of all declarations, multiplied by the Available Intertie Capacity. The remaining capacity will be made available as a block to Scheduling Utilities. Section 5(c)(2)(B) of this policy shall apply.

(3) Condition 3

When Condition 1 is not in effect and when the total surplus energy declared available by BPA and Scheduling Utilities is less than the total available Intertie Capacity, BPA's allocation will equal its declaration. The remaining Intertie capacity will be made available, first, as a block to satisfy the declarations of Scheduling Utilities, second, to U.S. Extraregional Utilities, and third to other œxtraregional Utilities. Section 3(d) of this policy shall not apply during Condition 3.

(e) Data Collection and Evaluation. Commencing when this policy goes into effect and continuing during the course of the experiment described in section 5(d), BPA will collect information on the following topics relevant to future allocation procedures:

(1) effect on BPA revenue of allocating to nonfederal utilities as a group rather than individually.

(2) impairment of Intertie access for California utilities presently lacking ownership in the southern portion of the Intertie,

(3) any loss of sales to BPA due to a failure to share unused capacity among California entities with ownership or contractual interests in the Intertie,

(4) effects of the experiment on small Scheduling Utilities.

During the course of the experiment, interested parties may submit written comments and recommendations on these issues.

(f) Findings and conclusions. At least 30 days before the end of the experiment described in section 5(d), BPA shall publish a report of its findings on the experiment and its decision on whether section 5(d), with possible modification, should be continued as the permanent method of Formula Allocation.

Section 6. Access for Qualified Extraregional Resources

(a) Assured delivery. Any request for Assured Delivery of power from a Qualified Extraregional Resource would be granted only by contract which, in addition to the Mitigation measures specified in section 4(d), must Include

benefits to BPA such as increased storage, improved system coordination or operation, or other consideration of value commensurate with the services provided. Proposed contracts would be evaluated by BPA and reviewed publicly to determine whether they would cause substantial interference with the Administrator's Power Marketing Program. An environmental review would also be conducted.

(b) Formula Allocation. Under Condition 3, energy from Qualified Extraregional Resources has access to the Intertie. In addition, BPA may provide Extraregional Utilities with Formula Allocation under other conditions, if the utility agrees by contract either to increased participation in the Pacific Northwest's coordinated planning and operation, or to provide other consideration of value, apart from the standard BPA wheeling rate, commensurate with the services provided.

Section 7. Fish and Wildlife Protection

(a) Purpose. New hydroelectric projects constructed in Protected Areas may substantially decrease the effectiveness of, or substantially increase the
need for, expenditures and other actions by 8PA, under Northwest Power Act section 4(h), to protect, mitigateâ or enhance fish and wildlife resources. Intertie access will not be provided to facilitate the transmission of power generated by any new hydroelectric projects located in Protected Areas and licensed after the effective date of this policy. This provision does not apply to added capacity at existing projects.

(b) Effect. This section imposes automatic operational limitations on a utility by reducing the amount of energy that can be scheduled over the Intertie, thereby increasing costs or reducing revenues for any utility owning
or acquiring the output of a Protected Area hydroelectric resource.

(c) implementation. Protected Area designations for stream reaches in the Columbia River 8asin are shown in Exhibit C to this policy. Exhibit C uses Environmental Protection Agency stream reach codes. Subject to review and possible modification, 8PA will consider the adoption of comprehensive state watershed management plans and a comprehensive protected area program developed by the Pacific Northwest Electric Power and Conservation Planning Council subsequent to implementation of this policy. 8PA will also consider revisions to Protected Area designations if the Council's Program is amended.

(d) Enforcement. If a Scheduling Utility or Nonscheduling Utility owns, or acquires the output from, a hydroelectric project covered under the restrictions of section 7(a), 8PA will reduce that utility's Formula Allocation by either the nameplate rating of the project (in the case of ownership>, or the amount of capacity acquired by contract.

(e) Exceptions.

(1) PURPA Projects. BPA will entertain requests that it not enforce the provisions of section 7 in situations where an Investor-owned utility has been compelled to acquire the output oF a Protected Area hydroelectric resource under section 210 of the Public Utilities Regulatory Policies Act (PURPA). To qualify for this exception, the investor-owned utility must demonstrate:

(A) that It has exercised all opportunities available under federal and state laws and regulations to decline to acquire the output of the

Protected Area resource in question:

(B) that it has petitioned its state :gulatory authority(ies) to reduce the rate(s) established under PURPA for purchases from Protected Area resources In recognition of the increased costs or reduced revenues caused by operation of section 7(c) of this policy:

(C) that BPA was provided reasonable notice of all relevant regulatory and judicial proceedings to allow for timely intervention in such proceedings; and

(D) after taking all of the foregoing steps and exhausting all reasonable opportunities for judicial review, that It was compelled to acquire the output of a Protected Area hydroelectric resource by final order of FERC or a state regulatory authority issued under PURPA.

(2) Proiects Contributing to Council's Fish and wildlife Program or 8PA investrints. Access will be automatically denied for projects developed in protected areas unless 8PA receives sufficient demonstration that a particular project will provide benefits to existing or planned 8PA fish and wildlife investments or the Council's Program. 8PA's determination will be based on:

(A) information provided by the project developer Federal and state fish and wildlife agencies, and tribes: or

(B) action by the Pacific Northwest Power Planning Council.

Section 8. Other Enforcement Provisions

(a) Whenever the terms of this policy are not being met, 8PA will Inform the appropriate utility of the nature of the noncompliance and actions that may be taken to achieve compliance. If noncompliance is not corrected within a reasonable period, 8PA may deny access for a resource and refuse to accept schedules.

(b) Upon approval of the proposed U.S.-Canada Free Trade Agreement by the Canadian Parliament and the United States Congress, any and all distinctions made in this policy between Canadian and United States Extraregional Utilities shall terminate on the effective date of the Agreement.

EXHIBIT A
EXISTING AGREEMENTS FOR INTERTiE CAPACITY

This is a list of existing BPA transmission contracts that were signed before the implementation of the NTIAP and will continue to receive Intertie access under the LTIAP.

Utility	BPA Contract No.	Expiration Date

Washington Water Power Company	DE-MS79-81BP90185	07/01/91
Washington Water Power Company	14-03-791101	09/01/88
Western Area Power Administration	DE-MS79-84BP91627	10/31/90

EXHIBIT B

INTERTIE CAPACITY AVAILABLE FOR ASSURED DELIVERY

BPA has reserved 800 MW of Intertie capacity to be available for nonfederal firm transactions. This capacity is allocated as follows:

A. Average Firm Surnius Allocations:

UTILITY	AVERAGE MW FIRM SURPLUS
Chelan County PUD #1	10
Cowlitz County PUD #1	45 1/
Douglas County PUD #1	0 2/
Eugene Water and Electric Board	14
Grant County PUD #1	26
Seattle City Light	23
Snohomish County PUD #1	0
Tacoma City Light	41 3/
Idaho Power Company	87
Montana Power Company	105 4/
Puget Sound Power and Light	0
Washâington Water Power	93
	444

NOTE: The Average Firs Surplus (AFS> is directly from the PNUCC Northwest Regional Forecast of March 1987 for the period. 1988-89 except as noted below. It Includes resources operational on- the effective date of this policy. Export contracts are included as loads. Utilities may use their AFS allocations for long term firm sales or for exchanges. Portland General Electric Company and Pacific Power & Light Company are not eligible for an AFS allocation because of their existing interconnections with the Southwest.

1/ Cowlitz Co. PUD's AFS is the amount of their existing export of the Longview Fibre resource. Longview Fibre is considered to be a Federal resource in the Northwest Regional Forecast and Is not included under Cowlitz.

2/ Douglas County PUD's AFS is 2: but Douglas has previously requested to show zero.

3/ The amount displayed for Tacoma Is the amount of their existing exports displayed in the Northwest Regional Forecast.

4/ Montana Power Company's AFS was increased from 80 MW to 105 MW in settlement of obligations under Northwest Power Act section 9(i)(3).

B. Intertie Capacity Available for Seasonal Exchanqes: The above allocations for sales of firm surplus may be used for exchanges. The remaining 356 MW of capacity is available on a first come-first serve basis for exchanges only under the terms of the LTIAP. If there is a decrease in a utility's firm surplus and the utility does not have a contract for that amount, BPA will allocate the difference to capacity available for exchanges by revising this Exhibit B.

EXHIBITT C
PROTECTED AREAS

Exhibit C corresponds to the Northwest Power Planning Council protected area
designations within the Columbia Basin, as, specified in the Columbia River
Basin Fish and Wildlife Program. Stream reaches designated as protected areas
are identified by Environmental Protection Agency streak reach codes.
Information about designations are contained on hard copy computer printouts
or computer diskette copies which are available to the public upon request:

Appendix C Glossary (same 82 ch 8)

Glossary

Alternating current (AC): electric current that reverses its direction of flow at regular
intervals and has alternately positive ad negative values; see Intertie.

Assured Delivery: firm transmission service provided by BPA under terms of the
Long-Term Intertie Access Policy under a transmission contract to wheel power
between a scheduling utility and a PSW utility.

California-Oregon Transmission Project (COTP): a consortium of California utilities ad other entities participating in the construction of the Third AC Intertie south of the Oregon-California border; also the 500-Kilovolt transmission line proposed by the COTP.

Capacity: the amount of power that can be produced by a generator or carried by a transmission facility at any instant. Also, the service whereby one utility delivers firm energy during another utility's period of peak usage with return made during the second utility's offpeak periods; compensation for this service may be with money, energy, or other services.

Demand Side Management: Strategies for reducing, redistributing, shifting, or shaping electrical loads, with a emphasis toward reducing or leveling load peak. These strategies can be accomplished by influencing when and how customers use electricity. Examples include conservation measures, rate incentives for shifting loads, more effective controls, and energy storage schemes.

Direct current (DC): electric current that may have pulsating characteristics but does not reverse direction at regular intervals, unlike alternating current; see Intertie.

Endangered Species Act (ESA): a act passed by Congress in 1973 and subsequently amended, which provides for the conservation of endangered and threatened species of fish, wildlife, and plants and their ecosystems.

Energy: in this document, energy refers generally to megawatthours and is different from "capacity" and "power".

Energy Policy Act of 1992: a act passed by Congress in 1992 that provides; among other things, for FERC authority to order transmission access.

Environmental Impact Statement (eis): a document prepared to assist Federal agencies in complying with the National Environmental Policy Act; a discussion and analysis of potential significant environmental impacts of the proposed action and alternatives.

Federal Energy Regulatory Commission (FERC): a Federal agency that reviews

BPA's rates, regulates transmission practices, and is responsible for enforcing provisions of the National Energy Policy Act.

Formula Allocation: the process by which Intertie capacity is made available for short-term sales of energy under the terms of BPA's Long-Term Intertie Access Policy.

Independent power producer (IPP): Non-utility producers or electricity who operate generation plants under the 1978 Public Utilities Regulatory Policy Act of 1978 (PURPA). May independent power producers are cogenerators who produce power as well as steam or heat for their own use and sell the extra power to their local utilities.

Inland Southwest (ISW): the States of Nevada, Arizona, Colorado, Utah, and New Mexico.

Intertie: relevant to this eis, the system of high-voltage transmission lines between the Pacific Northwest (Oregon) ad the Southwest (California), currently two 500-kilovolt alternating current lines and one 1000-kilovolt direct current line.

Intertie Development and Use (IDU) eis: BPA's eis completed in 1988 in aid of several BPA decisions reading expansion of Intertie capacity, adoption of the ~ng-Term Intertie Access Policy, ad design of long-term firm power contracts for marketing power over the Intertie.

Investor-owned utilities (IOUs): providers of electric power and other services whose programs are financed by private (nongovernment) investors in the company's stock and bonds.

Joint venture: used here generally to refer to a agreement in which BPA and another PNW party provide portions of the delivery to a PSW party.

Long-Term Intertie Access Policy (LTIAP): BPA's policy, developed in 1988, for allocating use of the Federal portion of the Intertie for a petiod of at least 20 years.

Megawatt (MW): a measure of electrical power or generating capacity; one million watts.

Memorandum of Understanding (MOU): an agreement entered into by BPA ad PNW parties interested in capacity ownership. The MOUs establish principles for the decision process on capacity ownership.

Million acre-feet (MAF): the measure of storage for fish flows; a acre-foot is the volume of water that will cover a area of one acre to a depth of one foot (326,000 gallons or 0.5 second foot days).

C2

National Marine Fisheries Service: a Federal agency of the U.S. Fish and Wildlife Service.

Non-attainment area: an area that has air pollution concentrations that do not comply with a portion of the National Ambient Air Quality Standards. See Chapter 2.

Non-Federal Participation (NFP): participation in some form, ranging up to full facilities ownership, by non-Federal utilities/entities in BPA's share of the Third AC Intertie.

Non-scheduling utilities: BPA customer utilities that do not operate a generation control area or that do not schedule power deliveries with BPA.

Northwest Power Planning Council: an eight-member body, with two members each from Oregon, Washington, Idaho, and Montana, authorized by the Northwest Power Act of 1980 for the purpose of coordinated fish and wildlife - resource planing.

Pacific Northwest (PNW): the States of Washington, Oregon, and Idaho, plus portions of Montana, Nevada, Utah, and Wyoming.

Pacific Power & Light Company (PP&L): a investor-owned utility that shares ownership of the existing Intertie and related facilities and the Third AC line with BPA and Portland General Electric.

Pacific Southwest (PSW): generally, the State of California.

Portland General Electric Company (PGE): a investor-owned utility that shares ownership of the existing Intertie and related facilities and the Third AC line with BPA and Pacific Power & Light.

Power: in this eis, refers generally to energy delivered during peak load hours at a specified capacity level.

Protected Areas: as developed by the Northwest Power Planing Council and enforced by the Long-Term Intertie Access Policy, areas protected from hydro project development due to the presence of wildlife, high-value resident fish, and anadromous fish, or areas that could support anadromous fish if investments were made in habitat, hatcheries, passage, or other projects.

Qualifying facility (QF): a renewable or cogeneration resource developed under the Public Utilities Regulatory Policy Act of 1978.

Resource Program: BPA's Resource Program develops a strategy and budget plan for development of conservation and other resources needed to meet BPA' s loads.

System Operation Review (SOR): a process of analysis and public review being conducted by the Bonneville Power Administration, the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, and cooperating agencies; the environmental analysis required to consider major changes in Columbia River system operations, including development of a mulitpl-use operating strategy for the river system âand renegotiation and renewal of the Pacific Northwest Coordination Agreement and other agreements related to the Columbia River Treaty between the United States and Canada.

Third AC: a construction project curreniny underway to expand the bidirectional capability of the Intertie transmission system; modifications to existing facilities and transmission additions in the Pacific Northwest will upgrade the portion of the AC Intertie north of the Oregon-California border to meet the planned increase for the southern portion (see COTP).

Transmission Agency of Northern California (TANC): a joint power agency consisting of 15 municipalities, public utility districts, and irrigation districts.

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PAGE TOC PAGE

Appendix D. Biological Assessment and Supporting Materials

OCT 21 1992

PGA

Mr. Doug Smithey
Fish and Wildlife Enhancement
U.S> Fish and Wildlife Service
911 NE. 11th Avenue
Portland, OR 97232-4181

Dear Mr. Swanson:

Subject: Request for List of Endangered and Threatened Species in the Bonneville Power Administration (BPA) Service Area, for Inclusion in the Non-Federal Participation (NFP) Environmental Impact Statement (eis)

The NFP eis considers alternatives for use of BPA's share of the Pacific Northwest-Pacific Southwest Intertie. This includes BPA powerâmarketing and non-Federal utility access to recently-added capacity. It addresses needs which have developed since BPA's Intertie Development and Use eis of 1988.

These alternatives may involve entities located throughout BPA's service area, which covers the States of Washington, Oregon, and Idaho: the portion of Montana west of the Continental Divide; and small portions of Wyoming, Utah, Nevada, and northern' California. Our study area also includes areas in Montana, Nevada, and Wyoming surrounding coal plants that serve the Pacific Northwest.

In compliance with section 7(c) of the amended Endangered Species Act, BPA is requesting a list of endangered and threatened species that may occur in the area of any of these facilities: and any information on these species that might be available, such as locations and' how they might be affected. If no alternatives, please notify BPA of this finding as well.

Our understanding is that Regions 2 and 6 will each take the lead to consult and coordinate the species list with their respective field offices and that each region will provide a single response to this request. We would, however, appreciate a list of contact at the appropriate field offices, should the need arise in the future for more detailed followup during the consultation process.

If possible, we would appreciate having any information you may obtain by December 18, 1992, so that we can include it in our draft eis. If you need additional information, or further assistance, please contact Yvonne Johnson at (503) 230-3596 or FTS 429-3596.

Sincerely,

Maureen R. Flynn
NFP eis Project Manager
Coordination and Review

D2

OCT 21 1992

PGA

Mr. Galen Buterbaugh
Regional Director
U.S. Fish and Wildlife Service
P.O. Box 25468
âDenver Federal Center
Denver, CO 80225

Dear Mr. Buterbaugh:

Subject: Request for list of Endangered and Threatened Species in the Bonneville Power Administration (BPA) Service Area, for Inclusion in the Non-Federal Participation (NFP) Environmental Impact Statement (eis)

The NFP eis considers alternatives for use of BPA's share of the Pacific Northwest-Pacific Southwest Intertie. This includes BPA power marketing and non-Federal utility access to recently-added capacity. It addresses needs which have developed since BPA's Intertie Development and Use eis of 1988.

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If possible, we would appreciate having any information you may obtain by December 18, 1992, so that we can include it in our draft eis. If you need additional information, or if you need further assistance, please contact Yvonne Johnson at (503) 230-3596 or FTS 429-3596.

Sincerely,

Maureen R. Flynn
NFP eis Project Manager
Coordination and Review

D4

Nov 4 1992

PG

Mr. Doug Smithey
Fish and Wildlife Enhancement
U.S. Fish and Wildlife Service
911 NE. 11th Avenue
Portland, OR 97232-4181

Dear Mr. Smithey:

Subject: Request for list of Endangered and Threatened Species in the Bonneville Power Administration (BPA) Service Area, for Inclusion in the Non-federal Participation (NFP) Environmental Impact Statement (eis)

In reference to our previous letter dated October 21, 1992, we are enclosing tables that show all major electric power plants in the Affected Environment for the NFP eis. Alternatives may influence expected operation of these plants.

If you need additional information, or futher assistance, please contact me at (503) 230-3596 or FTS 429-3596.

Sincerely,

Yvonne E. Johnson
Public Utilities Assistant

Enclosures

D5

NOV-4 1992

PG

Mr. John Rogers Jr. â â
Regional Director
U.S. Fish and Wildlife Service
Region 2
500 Gold Avenue SW, Room 3018
Albuquerque, NM 87103

Dear Mr. Rogers:

Subject: Request for list of Endangered and Threatened Species in the Bonneville Power Administration (BPA) -Service Area, for Inclusion in the Non-Federal Participation (NFP) Environmental Impact Statement (eis)

The NFP eis considers alternatives for use of BPAâs share of the Pacific Northwest-Pacific Southwest Intertie. This includes 8PA power marketing and non-Federal utility access to recently-added capacity. It addresses needs which have developed since 8PA's Intertie Development and Use eis of 1988.

These alternatives may involve entities located throughout 8PAâs service area, which covers the States of Washington, Oregon, and Idaho; the portion of Montana west of the Continental Divide; and small portions of Wyoming, Utah, Nevada, and northern California. Our study area also includes areas in Montana, Nevada, and Nyoming surrounding coal plants that serve the Pacific Northwest.

In compliance with section 7(c) of the amended Endangered Species Act, 8PA is requesting a list of endangered and threatened species that may occur in the area of any of these facilities; and any information on these species that might be available, such as locations and how they might be affected. If no species or their critical habitat are being or will be affected by these alternatives, please notify BPA of this finding as well.

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âThe enclosed tables show all major electric power plants in the Affected Environment for the NFP eis. Alternatives may influence expected operation of these plants.

If possible, we would appreciate having any information you may obtain by December 18, 1992, so that we can include it in our draft eis. If you need additional information, or if you need further assistance, please contact âYvonne Johnson at (503) 230-3596 or FTS 429-3596.

Sincerely,

Maureen R. Flynn
NFP eis Project Manager

Enclosures

D7

Nov -4 1992

PGA

Mr. Galen Buterbaugh
Regional Director
U.S. Fish and Wildlife Service
P.O. Box 25468
Denver Federal Center
Denver, CO 80225

Dear Mr. Buterbaugh:

Subject: Request for list of Endangered and Threatened Species in the Bonneville Power Administration (BPA) Service Area, for Inclusion in the Non-Federal Participation (NFP) Environmental Impact Statementâ (eis)

In reference to our previous letter dated October 21, 1992, we are enclosing tables that show all major electric power plants in the Affected Environment for the NFP eis. Alternatives riy influence expected operation of these plants. â â

If you need additional information, or if you need further assistance, please contact meat (503) 230-3596 or FTS 429-3596.

Sincerely,

Yvonne E. Johnson
Public Utilities Assistant

Enclosures

D8

Table D-1 FEDERAL COLUMBIA RIVER POWER SYSTEM GENERAL SPECIFICATIONS OF PROJECTS EXISTING, AUTHORIZED OR LICENSED, AND POTENTIAL NANEPLATE RATING OF INSTALLATIONS September 24, 1985

	Oper- ating		Initial	Number
Number	Number	Number		

Project	Type	Agen- cy	State	Stream (if H) City (if Fuel)1	Date in Service	of 2/ Units	Nornoplote Rating-kW	of Units	Nameplate Rating-kW	of Units	Nameplate Rating-kW	of Units	Nornoplote Rating-kW
Minidoka	HH	BR	ID	Snake	05/07/09	7		13				7	13,400
Boise Rvr Div	H	BR	ID	Boise	05/00/12	3	1,500	3	1,500				
Black Canyon	H	BR	ID	Payette	12/00/25	2	8,000	2	8,000				
Bonneville	H	CE	OR-WA	Columbia	06/06/38	18-2	1,076,600	18-2	1,076,600				
Grand Coulee	H	BR	WA	Columbia	09/28/41	24-3	6,163,000	6	4,200,000	30-3	10,363.000		
Anderson Rnch	H	BR	ID	S Fk Boise	12/15/50	2	40,000	1	13,500	3	53,500		
Hungry Horse	H	BR	MT	S Fk Flathead	10/29/52	4	285,000	4	285,000				
Detroit	H	CE	OR	N Santiam	07/01/53	2	100,000	2	100,000				
McNary	H	CE	OR-WA	Columbia	11/06/53	14	980,000	6	747,000 3/			20	1,727,000
Big Cliff	H	CE	OR	N Santiam	06/12/54	1	18,000	1	18,000				
Lookout Point	H	CE	OR	M Fk Willamette	12/16/54	3	120,000	3	120,000				
Albeni Falls	H	CE	ID	Pend Oreille	03/25/55	3	42,600	3	42,600				
Dexter	H	CE	OR	M Fk Willamette	05/19/55	1	15,000	1	15,000				
Chief Joseph	H	CEE	WA	Columbia	08/28/55	27	2,069.000	13	1,573,000	40	3,642,000		
Chandler	H	BR	WA	Yakima	02/13/56	2	12,000	2	12,000				
Palisades	H	BR	ID	Snake	02/25/57	4	118,750	2	135,000	6	253,750		
the Dalles	H	CE	OR-WA	Columbia	05/13/57	22-2	1,807,000	22-2	1,807,000				
Roza	H	BR	WA	Yakima	08/31/58	1	11,250	1	11,250				
Ice Harbor	H	CE	WA	Snake	12/18/61	6	602,880	6	602,880				
Hills Creek	H	CE	OR	M Fk Willamette	05/02/62	2	30,000	2	30,000				
Cougar	H	CE	OR	S Fk Mckenzie	02/04/64	2	25,000	1	35,000			3	60,000
Green Peter	H	CE	OR	Middle Santiam	06/09/67	2	80,000	2	80,000				
John Day	H	CE	OR-WA	Columbia	07/17/68	16	2,160,000	4	540,000			20	2,700,000
Foster	H	CE	OR	South Santiam	08/22/68	2	20,000	2	20,000				
Lower Monumental	H	CE	WA	Snake	05/28169	6	810,000	6	810,000				

Little Goose   H CE WA   Snake   05/19/70   6   810,000
6   810,0000
Dworshak   H CE ID   N Fk Cleanwater 09/18/74   3   400,000
3   660,000   6   1,060,000
Grand
 Coulee PG   PG BR WA   Columbia   12/30/74   6   300,000
6   300,000
Lower Granite H CE WA   5nake   04/15/75   6   810,000
6   810,000
Libby   H CE MT   Kootenai   08/29/75   5   525,000
3   315,000 4/   8   840,000
Lost Creek   H CE OR   Rogue   12/01/77   2   49,000
2   49,000
Libby
Reregulating   H CE MT   Kootenai
3   76,400   3   76,400
Strube   H CE OR   S Fk Mckenzie
1   4,500   1   45,000
Teton   H BR ID   Teton
3   30,000   3   30,000

Total Number of Units and Nameplate Rating   204-7   19,502,980
24   2,407,900   22   5,921,500 250-7   27,832,380

Total Number of Projects   31
3   0   33

1/ CE - Corps of Engineers Br - Bureau of Reclamation, BPA - Branch of Generation Planning
2/ Numbers after dashes indicate auxillary units.
3/ McNary Second Powerhouse estimates includes six unites at 124.500 kW each.
4/ Libby Unties 6. 7, 8 at 105,000 kW each have been deferred.

Table D-2 MAJOR THERMAL GENERATING RESOURCES IN THE PACIFIC NORTHWEST

Plant	Location	Net Capability (MW)
Nuclear		
Trojan	Rainier, OR	1,080
WPPSS No. 2	Hanford, WA	1,100
WPPSS No. 1 & 3 (suspended)	Hanœord/Satsop, WA	2,490
Coal		
Colstrip No. 1	Colstrip, MT	330

No. 2	Colstrip, âMT	330
No. 3	Colstrip, MT	700
No. 4	Colstrip, MT -	700
Jim Bridger No. 1	Rock Springs, WY	500
No. 2	Rock Springs, WY	500
No. 3	Rock Springs, WY	500
No. 4	Rock Springs, WY	500
Centralia No. 1	Centralia, WA	640
No. 2	Centralia, WA	640
Boardman	Boardman, OR	530
Valmy No. 1 â& 2	Valmy NV	522

Source: Western Systems Coordinating Council, "Summary of Estimated Loads and Resources" issued April 1986.

Table D-3 CALIFORNIA POWER PLANT OPERATION DATA: FUEL USE CHARACTERISTICS FOR PLANTS INDICATING CHANGE IN GENERATION

Power Plant/ Unit Number	Location County State	Util- ity	Net Cap. MW	Primary Fuel	Secondary Fuel	Primary Fuel Trans Meth.	Secondary Fuel Trans Meth.
Contra Costa 6	Contra Costa. CA	PG&E	340	Natural Gas	Fuel Oil No.6	Pipeline	Pipeline
Contra Costa 7	Contra Costa. CA	PG&E	340	Natural Gas	Fuel Oil No.6	Pipeline	Pipeline
Etiwanda 3	Sin Bern., CA	SCE	320	Fuel Oil No.4	Natural Gas	Pipeline	Pipeline
Etiwanda 4	San Bern.. CA	SCE	320	Fuel Oil No.4	Natural Gas	Pipeline	Pipeline
Naynes 1	Los Angeles. CA	LDWP	222	Fuel Oil No.6	Natural Gas	Pipeline	Pipeline
Haynes 3	Los Angeles. CA	LDWP	222	Fuel Oil No.6	Natural Gas	Tr/Pl/Shipâ	Pipeline
Haynes 4	Los Angeles. CA	LDWP	222	Fuel Oil No.6	Natural Gas	Tr/Pl/Ship	Pipeline
Haynes 5	Los Angeles. CA	LDWP	341	Fuel Oil No.6	Natural Gas	Tr/Pl/Ship	Pipeline
Haynes 6	Los Angeles. CA	LDWP	341	Fuel Oil No.6	Natural Gas	Tr/Pl/Ship	Pipeline
Hunt. B. 3	Orange. CA	SCE	215	Fuel Oil No.6	Natural Gas	Pl/Ship	Pipeline
Hunt. B. 4	Orange. CA	SCE	225	Fuel Oil No.4	Natural Gas	Pl/Snip	Pipeline
Morro Bay 1	San Lu. Ob.. CA	PG&E	163	Natural Gas	Fuel Oil No.6	Pipeline	Ship
Morro Bay 2	San Lu. Ob.. CA	PG&E	163	Natural Gas	Fuel Oil No.6	Pipeline	Ship

Morro Bay 3	San Lu. Ob.. CA	PG&E	331	Natural Gas	Fuel Oil No.6	Pipeline	Ship
Morro bay 4	San Lu. Ob.. CA	PG&E	331	Natural Gas	Fuel Oil No.6	Pipeline	Ship
Moss Land. 4	Monterey. CA	PG&E	117	Natural Gas	Fuel Oil No.6	Pipeline	Ship
Moss Land. 5	Monterey, CA	PG&E	117	Natural Gas	Fuel Oil No.6	Pipeline	Ship
Moss Land. 7	Monterey. CA	PG&E	739	Natural Gas	Fuel Oil No.6	Pipeline	Ship
Pittsburg 1	Contra Costa. CA	PG&E	163	Natural Gas	Fuel Oil No.6	Pipeline	Pipeline
Pittsburg 4	Contra Costa. CA	PG&E	163	Natural Gas	Fuel Oil No.6	Pipeline	Pipeline
Pittsburg 5	Contra Costa. CA	PG&E	325	Natural Gas	Fuel Oil No.6	Pipeline	Pipeline
Pittsburg 6	Contra Costa, CA	PG&E	325	Natural Gas	Fuel Oil No.6	Pipeline	Pipeline
Pittsburg 7	Contra Costa. CA	PG&E	720	Natural Gas	Fuel Oil No.6	Pipeline	Pipeline
Scattergood 1	Los Angeles. CA	LDWP	179	Fuel Oil No.6	Natural Gas	Truck-Rail	Pipeline
Scattergood 2	Los Angeles. CA	LDWP	179	Fuel Oil 10.6	Natural Gas	Truck-Rail	Pipeline
Scattergood 3	Los Angeles. CA	LDWP	284	Natural Gas	None	Pipeline	-----
Valley 1	Los Angeles. CA	LDWP	101	Fuel Oil No.6	Natural Gas	Truck-Rail	Pipeline
Valley 2	Los Angeles. CA	LDWP	101	Fuel Oil No.6	Natural Gas	Truck-Rail	Pipeline
Valley 3	Los Angeles, CA	LDWP	164	Fuel 011 No.6	Natural Gas	Truck-Rail	Pipeline
Valley 4	Los Angeles. CA	LDWP	160	Fuel Oil No.6	Natural Gas	Truck-Rail	Pineline

SOURCE: Western Systems Coordinating Council. "Coordinated Bulk Power Supply Prograa. 1984-1994." WSCC. April, 1985.

Table D-4 LOCATIONS OF SELECTED COAL-FIRED POWER PLAATS AND LOCAL POPULATIONS

Plant	Utility	location Co., State	County Pop.	Plant Site Community Population	Nearby* Communities >1000
PACIFIC N0RTRWSST					
Boardman	PGE	Morrow, OR	7,519	Boardman	Umatilla, 3199

1,261 Hermiston,
9,408
Stanfield,
1,568

Centralia 1-2 PPL, Lewis, WA 56,025 Centralia Chehalis,
6,100
11,555 Tumwater,
6,705
Olympia,
27,447
Fords
Prarie, 2,582
Raymond,
2,991

Colstrip 1-3 MPC Rosebud, MT 9,899 Colstrip
1,476

Jim Bridger 1-4 PPL Sweetwater, WY 41,723 Rock Springs Green
River, 12,807
19,458

Valmy 1-2 SSP Humbolt, NV 9,434 V&1my Kattle
Mt., 2,749
<1,000
Winnemucca, 4,140

INAND SOUTHWEST

Cholla 1-4. APS Navaho, AZ 67,629 Joseph City Holbrook,
5,785
<1,000 Snow Flake,
3,510
Taylor,
1,915
Winslow,
7,921

Coronado 1-2 SRP Apache, AZ 52,108 St. Johns Eager,
2,797
3,368
Springerville, 1,452

Concho,
Hunt,

					Nutrioso, <1,000 Vernon:
Hunter 1-2	UPLC	Emery, UT	11,451	Castle Dale 1,910	Orangeville, 1,309 Huntington, 2,316 Wellington, 1,406 Price, 9,086

Table D-5

Plant	Utility	Location Co., State	County Pop.	Plant Site Cornunity Population	Nearby* Communities >1OOO
Mohave 1-2	SCE	Clark, NV	463,087	Laughlin <1,000	Las Vegas, 164,674 Henderson, 24,363 Boulder City, 9,590 Winchester, 19,728
San Juan 1-4	PNW	San Juan, NM	81,433	Waterflow <1,000	Kirtland, 2,358 Shiprock, 7,237 Farmington, 31,222 Aztec, 5,512 Bloomfield, 4,881
Springerville	TEPC	Apache, AZ	52,108	Springerville	Eager, 2,791

1,452 St. Johns, 3,368

McNary, 1,320

Pinetop, 1,527

Source: U.S. - Department of Commerce, Bureau of the Census, General Social and Economic Characteristics, (states indicated) (Washington, D.C., USGP0, 1983) -

*â Nearby communities within approximately 40 miles of the plant site.

D13

United State Department of the Interior
FISH AND WILD LIFE SERVICE
911 NE. 11th Avenue
Portland, Oregon 97232-4181

JAN 19 1993

Ms. Yvonne E. Johnson
Public Utilities Assistant
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

Dear Ms. Johnson:

This is in reference to the Bonneville Power Administration's (BPA) preparation of the Non-Federal Participation Draft Environmental Impact Statement, and your request of October 21, 1992, for a list of endangered and threatened species that may occur in the BPA service area.

Our letter dated November 20, 1992, provided you with a list of federally listed endangered and threatened species that may occur in the states of California, Idaho, Nevada, Oregon, and Washington. However, we also stated that any additional information you could send us concerning the Non-Federal Participation Intertie Project would be helpful in delineating which species might occur in the vicinity of project actions. Your reply by letter' dated November 4, 1992, gave general specifications on all major electric power generating facilities in the BPA service area.

Our Field Office's have reviewed the new information and have compiled species

lists relative to the location of the power plants and appurtenant facilities.
Please take note of the comments that our Field Office's have made in the memorandum accompanying the enclosed species lists. The lists and comments are submitted for your review as follows:

Species List Enclosure No.	BPA Service Area (by state)	FWS Field Office responsible for list
1	California	Carlsbad, CA
2	California	Sacramento, CA
3	California	Ventura, CA
4	Idaho	Boise, ID
5	Nevada	Reno, NV
6	Oregon	Portland, OR

Ms. Yvonne E. Johnson

The species information compiled for projects in the State of Washington is being revised and will be sent under separate cover as soon as possible. If you have any questions about the enclosed material, please contact John Nuss of our staff at 503-231-6241.

Sincerely,

H. Dale Hall
Assistant Regional Director
Ecological Services

Enclosures

ENCLOSURE No. 1

United States Department of the Interior

FISH AND WILDLIFE SERVICE

FISH AND WILDLIFE ENHANCEMENT
Carlsbad Office
2730 Loker Ave. West
Carlsbad, California 92008

December 30, 1992

Memorandum

To: Assistant Regional Director - Fish and wildlife Enhancement Portland, Oregon (atten: John Nuss)

From: Field Supervisor

Subject: BPA' s Request for List of Endangered and Threatened Species and Other Information for Inclusion in BPA Service Area Non-Federal Participation Draft Environmental Statement

Attached is a response to your request dated November 27, 1992. Included are species lists for Etiwanda - San Bernardino County, Huntington Beach - Orange County, and Los Angeles County. LA County covers all of the projects identified as occurring in Los Angeles.

If you have any questions, please contact Susan Wynn of my staff at (619) 431-9440.

Attachment

D17

Listed Proposed, Endangered, Threatened,
and Candidate Species
That may occur in the Area of
Bonneville Power Administration Service Area
(1-6-93-SP-74)

Itiwanda, San Bernardino - California

Listed Species
Birds

Least Bell's vireo Vireo bellii nusillus	(E)
Bald eagle Haliaeetus leucocephalus	
American peregrine falcon Falco peregrinus anatum	(E)
Peregrine falcon Falco peregrinus	(E)

Fish

Unarmored threespine stickleback Gasterosteus aculeatus williamsoni (E)

Plants

Slender-horned spineflower Dodecahema lentoceras (E)
Santa Ana River wooly-star Eriastrum densifolium sanctorum (E)

Proposed Species

Birds

California gnatcatcher Polioptila californica californica (PE)

Candidate Species

Mammals

San Bernardino kangaroo rat Dipodomys merriami parvus (2)
Spotted bat Euderma maculatum (2)
Greater western mastiff-bat Eumops perotis californicus (2)
San Diego black-tailed jackrabbit Lepus californicus bennettii (2)
California leaf-nosed bat Macrotis californicus (2)
Occult little brown bat Myotis lucifugus occultus (2)
Southwestern cave myotis Myotis velifer brevis (2)
San Diego desert woodrat Neotoma lepida intermedia (2)
Northwestern San Diego pocket mouse Perognathus fallax fallax (2)
Pallid San Diego pocket mouse Perognathus fallax pallidus (2)
Los Angeles pocket mouse Perognathus longimembris brevinasus (2)
Pacific western big-eared bat Plecotus townsendii townsendii (2)
Brush rabbit Sylvilagus bachmani (R1)

Birds

Tricolored blackbird Agelaius tricolor (2)
Southern California rufous-crowned sparrow Aimophila ruficeps canescens (2)
Bell's sage sparrow Amphispiza bellii bellii (2)
Ferruginous hawk Buteo regalis (2)
San Diego cactus wren Campylorhynchus buirneicappilus couesi (2)

Mountain plover Charadrius montanus (2)
Southwestern willow flycatcher Emnidonax trailii extimus (2)
California horned lark Eromophila alpestris actia (2)
Loggerhead shrike Lanius ludovicianus (2)

Santa Ana sucker Catastomus santaanae (2)

Reptiles

Southwestern pond turtle Clemmys marmorata pallida (2)
orange-throated whiptail Cnemidorphorus hyperythurs (2)
Coastal western whiptail Cnemidorphorus tigris

multiscutatus	(2)
Northern red diamond rattlesnake Crotalus ruber ruber	(2)
San Bernardino ringneck snake Diadophis punctatus modestus	(2)
San Diego ringneck snake Diadonhis nunctatus similis	(2)
Coastal rosy boa Lichanura trivirgata rosafusca	(2)
San Diego horned lizard Phrynosoma coronatum blainvillei	(2)
Coast patch-nosed snake Salvadora hexalepis viroultea	(2)
Two-striped garter snake Thamnophis hammondii	(2)

Amphibians

Arroyo southwestern toad Bufo microscaphus californicus	(2)
California red-legged frog Rana aurora draytoni	(2)
Foothill yellow-legged frog Rana boylii	(1)
Western spade foot Scaphipus hammondii	(R)

L

Plants

Thread-leaved brodiaea Brodiaea fillifolia	(1)
Orcutt' s brodiaea Brodiaea orcuttii	(2)
Many-stemmed live forever Dudleya multicaulis	(2)
Pringle's monardella Monardella pringlei	(1)
Little mousetail Myosurus minimus ssp. apus	(2)
Nevin's barberry Berberis nevinii	(1)
Parry's spineflower Chorizanthe parrvii var. parrvi	(2)
Parish's bush-mallow Malacothamnus parishii	(2)

Huntington Beach, Orange county California

Listed Species

Birds

Bald eagle Haliaeetus leucocephalus	(E)
Brown pelican pelecanus occidentalis	(E)
California least tern Sterna antillarum browni	(E)
Least Bell's vireo ~ bellii pusillus	(E)
American peregrine falcon Falco neregrinus anatum	(E)
Artic peregrine falcon Falco neregrinus tundrius	(T)
Peregrine falcon Falco peregrinus	(E)
Light-footed clapper rail Rallus longirostris levipes	(E)

Plants

Salt marsh bird's beak Cordylanthus maritimus ssp. maritimus	(E)

Proposed Species

Birds

Western snowy plover Charadrius alexandrinus nivosus	(PT)
California gnatcatcher Polioptila californica californica	(PE)

Fish

Tidewater goby Eucyclogobius newberryi	(PE)

Plants

Gambel's bittercress Rorippa gambellii	(PE)

Candidate Species

Spotted - bat Euderma maculatum (2)
Greater western mastiff-bat Eumops perotis californicus (2)
San Diego black-tailed jackrabbit Lenus californicus bennettii (2)
California leaf-nosed bat Macrotis californicus (2)
Stephens' California vole Microtus californicus stephensi (2)
San Diego desert woodrat Neotoma lepida intermedia (2)
Southern grasshopper mouse Onychomys torridus ramona (2)
Pacific little pocket mouse Perognathus longimembris pacificus (2)
Southern marsh harvest mouse Reithrodontomys megalotis limicola (2)
Brush rabbit Sylvilagus bachmani (R)

Birds
Tricolored blackbird Agelaius tricolor (2)
Southern California rufous-crowned sparrow Aimophila ruficeps canescens (2)
Bell's sage sparrow Amphispiza bellii bellii (2)
Ferruginous hawk Buteo regalis (2)
San Diego cactus wren Campylorhynchus burneicanppilus couesi (2)
Reddish egret Egretta rufescens (2)
California horned lark Eromophila alpestris actia (2)
Harlequin duck Histrionicus histrionicus (2)
Western least bittern Ixobrychus exilis hesperis (2)
Loggerhead shrike Lanius ludovicianus (2)
Black rail Laterallus Jamaicensis. coturniculus (2)
Belding's savannah sparrow Passerculus sandwichetisis belding (2)
Large-billed savannah sparrow Passerculus sandwichensis rostratus (2)
White-faced ibis Plegadis chihi (2)
Elegant tern Sterna elegans (2)
California spotted owl Strix occidentalis occidentalis (2)

Reptiles
Southwestern pond turtle Clemmys marmorata pallida (1)
San Diego banded gecko Coleonyx variegatus abbotti (2)
orange-throated whiptail Cnemidorphorus hyperythrus (2)
Coastal western whiptail Cnemidorphorus tiaris

multiscutatus (2)
Northern red diamond rattlesnake Crotalus ruber ruber (2)
San Bernardino ringneck snake Diadophis punctatus modestus (2)
San Diego ringneck snake Diadophis punctatus similis (2)
Coastal rosy boa Lichanura trivirgata rosafusca (2)
San Diego horned lizard phrynosoma coronatum blainvillei (2)
Coast patch-nosed snake Salvadora hexalepis virgultea (2)
Two-striped garter snake Thamnophis hammondii (2)

Amphibians

Western spade foot Scaphionus hammondii (R)

Invertebrates

Ca. brackish water snail Tyronia imitator (2)
Oblivious tiger beetle Cicindela latesignata obliviosa (2)
Globose dune beetle Coelus globosus (2)
Hermes copper butterfly Lycaena hermes (2)
Wright's checkerspot butterfly Eunhvdryas editha guino (2)
Salt marsh skipper Panoquina errans (2)
Wandering skipper Pseudocopaeodes eunus eunus (2)

Plants

Aphanisma Aphanisma blitoides (2)
Marsh locoweed Astragalus pycnostachys var. lanosissimus (1)
San Fernando Valley spineflower Chorizanthe narrvi var. fernandina (1)
Los Angeles sunflower Helianthus nuttalli ssp. elongata (1)
Southern spikeweed Hemizonia australis (2)
Coulter's saltmarsh daisy Lathenia glabrata ssp. coulteri (2)

Los Angeles County - California

Listed Species

Mammals

San Joaguin kit fox Vulpes macrotis mutica (E)

Birds

Bald eagle Haliaeetus leucocephalus (E)
Brown pelican Pelecanus occidentalis (E)
California least tern Sterna antillarum browni (E)
Least Bell's vireo Vireo bellii pusillus (E)
American peregrine falcon Falco peregrinus anatum (E)
Artic peregrine falcon Falco peregrinus tundrius (T)
Peregrine falcon Falcon peregrinus (E)

Fish

Unarmored threespine stickleback Gasterosteus aculeatus williamsoni (E)

Invertebrates

El Segundo blue butterfly Euphilotes auretorum fumosum (E)
Palos Verdes blue butterfly Glaucopsyche lygdamus (E)

Plants

Salt marsh bird's beak Cordylanthus maritimus ssp. maritimus (E)

Proposed Species

Birds

Western snowy plover Charadrius alexandrinus nivosus (PT)
California gnatcatcher Polioptila californica californica (PE)

Fish

Tidewater goby Eucyclogobius newberryi (PE)

Plants
Proposed Species
Braunton's milkvetch Astragalus brauntonii (PI)
Marcescent dudleya Dudleya cymosa ssp. marcescens (PT)
Santa Monica Mtns. dudleya Dudleya cymosa ssp. ovatifolia (PT)
California orcutt's grass Orcuttia californica (PI)
Lyon's pentachaeta Pentachaeta lyonii (PI)
Gambel's bittercress Rorippa gambellii (PI)

Candidate Species
Mammals
San Diego black-tailed jackrabbit Lepus californicus bennettii (2)
California leaf-nosed bat Macrotis californicus (2)
Spotted bat Euderma maculatum (2)
Stephens' California vole Microtus californicus stephensi (2)
Greater western mastiff-bat Eumops perotis californicus (2)
San Diego desert woodrat Neotoma lepida intermedia (2)
Southern grasshopper mouse Onychomys torridus ramona (2)
San Diego pocket mouse Perognathus fallax fallax (2)
Los Angeles pocket mouse Perognathus longimembris brevinasus (2)
Pacific little pocket mouse Perognathus longimembris pacificus (2)
Southern marsh harvest mouse Reithrodontomys megalotis limicola (2)
Ornate salt marsh shrew Sorex ornatus saliconicus (2)
Brush rabbit Sylvilagus bachmani (R)

Birds
Tricolored blackbird - Agelaius tricolor (2)
Southern California rufous-crowned sparrow Aimophila ruficeps canescens (2)
Bell's sage sparrow Amphispiza bellii bellii (2)
Ferruginous hawk Buteo regal is (2)
San Diego cactus wren Campylorhynchus bruneicanpilus couesi (2)
Southwestern willow flycatcher Emnidonax trailii extimus (1)
California horned lark Eromophila alpestris actia (2)
Harlequin duck Histrionicus histrionicus (2)
Western least bittern Ixobrychus exilis hesperis (2)
Loggerhead shrike Lanius ludovicianus (2)
Belding's savannah sparrow Passerculus sandwichensis

belding (2)
White-faced ibis Plegadis chihi (2)
Elegant tern Sterna elegans (2)
California spotted owl Strix occidentalis occidentalis (2)

Rentiles
Southwestern pond turtle Clemmys marmorata pallida (1)

San Diego banded gecko Coleonyx variegatus abbotti (2)
Coastal western whiptail Cnemidornhorus multiscutatus (2)
San Bernardino ringneck snake Diadonhis punctatus modestus (2)
San Diego ringneck snake Diadonhis nunctatus similis (2)
Coastal rosy boa Lichanura trivirgata rosafusca (2)
San Diego horned lizard Phrynosoma coronatum blainvillei (2)
Coast patch-nosed snake Salvadora hexalepis virgultea (2)
Two-striped garter snake Thamnophis hammondii (2)

Amphibians
Western spade foot Scaphipus hammondii (R)
Foothill yellow-legged frog - Rana boylii (1)

Fish
Santa Ana sucker Catastomus santaanae (2)

Invertebrates
Ca. brackish water snail Tyronia imitator (2)
Santa Monica shieldback katydid Neduba longinennis (2)
Oblivious tiger beetle Cicindela latesignata obliviosa (2)
Globose dune beetle Coelus globosus (2)
Lange's El Segundo dune weevil Onychobaris langei (2)
Dorothy's El Segundo dune weevil Trigonscuta dorothea dorothea (2)
Hermes copper butterfly Lycaena hermes (2)
Wright's checkerspot butterfly Euphydrayas editha quino (2)
Salt marsh skipper Panoouina errans (2)
Wandering skipper Pseudocopaeodes eunus eunus (2)

Plants
Aphanisma Anhanisma blitoides (2)
Bear Valley woollypod Astraaalus leucolobus (2)
Marsh locoweed Astragalus pycnostachys var. lanosissimus (1)
Coastal dunes milk vetch Astragalus tener var. titi (2)
Nevin' s barberry Berberis nevinii (1)
Scalloped moonwort Botrvchium crenulatum (2)
Thread-leaved brodiaea Brodiaea filifolia (1)
Peirson's morning-glory Calystegia peirsonii (2)
Mt. Gleason indian paintbrush Castilleja gleasonii (2)
San Fernando Valley spineflower Chorizanthe parrvi var. fernandina (1)
Beach spectaclepod Dithyrea maritima (2)
Blochmann's dudleya Dudleva blochmannae ssp. blochmannae (2)
San Gabriel River dudleya Dudleya cvmosa ssp. crebrifolia (2)
San Gabriel Mtns. dudleya Dudleya densiflora (1)

Many-stemmed dudleya Dudleya multicaulis (2)
Bright green dudleya Dudleya virens (2)
San Gabriel bedstraw Galium grande (2)
Palmer's grappling-hook Harpagonella palmeri (2)
Los Angeles sunflower Helianthus nuttalli ssp. parishii (1)
Southern spikeweed Hemizonia australis (2)

Smooth spikeweed Hemizonia laevis (2)
Santa Susana tarplant Hemizonia minthornii (2)
Coulter's saltmarsh daisy Lasthenia glabrata ssp. coulteri (2)
Humboldt's tiger lily Lilium humboldtiiâ var. ocellatum (2)
Lemon lily Lilium parryi (2)
Orcutt's linanthus Linanthus orcuttii (2)
Davidson's bush mallow Malacothamnus davidsonii (2)
Chaparral beargrass Nolina cismontana (2)
Rock Creek broomrape Orobanche valida ssp. valida (2)
Gairdner's yampah Perideridia gairdneri ssp. gairdneri (2)
Ballona cinquefoil Potentilla multijuga (1)
Parish's gooseberry Ribes divaricatum var. parishii (2)

1 R = Species which is rare but is not listed as a candidate species at this time.

D24

ENCLOSURE No. 2

D25

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Fish and Wildlife Enhancement
Sacramento Field Office
2800 Cottage Way, Room E-1803
Sacramento, California 95825-1846

In Reply Refer To:
1-1-93-SP-235 December 17, 1992

Memomdum

To: Assistant Regional Director, Fish and Wildlife Enhancement
Portland, Oregon (AFWE) (Attn: John Nuss)

From: Assistant Field Supervisor, Sacramento Field Office
Sacramento, California (SFO)

Subject: Bonneville Power Administration Request for List of Threatened and Endangered Species in Their Service Area by December 18, 1992.

In accordance with your memorandum dated November 27, 1992. the above subject species'âlist is submitted for inclusion in the Regional office response.

If you or the Bonneville Power Administration have any questions or need additional information, please contact Laurie Stuart Simons of this office at (916) 978-4866. For questions concerning the threatened winter-run chinook salmon, please contact Jim Lecky, Endangered Species Coordinator, at the National Marine Fisheries Service, Southwest Region, 501 West Ocean Boulevard,
Suite 4200, Long Beach California 90802-4213, or call him at (310) 980-4015.

Wayne S. White

Attachment

D26

ATTACHMENT A

LISTED AND PROPOSED ENDANGERED AND THReaTENED SPECIES AND CANDIDATE SPECIES THAT HAY OCCUR IN THE SERIVE ARea OF THE BONNEVILLE POWER ADMINISTRATION IN CONTRA COSTA COUNTY, CALIFORNIA (1-1-93-SP-235, DECEMBER 17, 1992)

Listed Species

Fish
winter-run chinook salmon, 0ncorh~chus tshawytscha (T)

Birds
bald eagle, Haliaieetus leucocephalus (E)
American peregrine falcon, Falco peregrinus anatum (E)..
Aleutian Canada goose, Bran Ca canadensis lerncopareia (T)
California brown pelican, Pelecanus occidentalis californicus (E)
California clapper rail, Rallus longirostris obsoletus (E)

Mammals
salt marsh harvest mouse, Reithrodontomys raviventris (E)
San Joaquin kit fox, Vulpes macrotis mutica (E)

Invertebrates
bay checkerspot butterfly, Euphydryas editha bayensis (T)
Lange's metalmark butterfly, Apodemia mormo langei (E)

PLants
large-flowered fiddleneck, Amsinckia grandiflora (E)
Contra Costa wallflower, Erysimum capitatum var. angustatum (E)
Antioch Dunes evening primrose, Oenothera deltoides ssp. howellii (E)

Proposed Species

Fish
delta smelt, Hyppomesus transpacificus (PT)

Reptiles
giant garter snake, Thamnophis gigas (FE)

Invertebrates
longhorn fairy shrimp, Branchinecta longiantenna (FE)
vernal pool fairy shrimp, Branchinecta lynchi (FE)

California linderiella, Linderiella occidentalis (PE)

Plants
No Cornon Name, Suaeda californica (FE)

Candidate Species

Fish
tidewater goby, Euclyclogobius newberryi (1*))
Sacramento perch, Archoplites interruptus (2)
Sacramento splittail, Pogonochthys macrolepidotus (2)
green sturgeon, Acipenser medirostris (2R)
longfin smelt, Spirinchus thaleichthys (2R)

D27

Amphibians
California tiger salamander. Ambystoma californiense (2.)
California red-legged frog, Rana aurora draytonii (1.)
western Spade foot toad, Scaphipus harnondi hammondi (2R)
foothill yellow-legged frog, Rana boylei (2)

Reptiles
Alameda whipsnake. Masticophis lateralis euryxanchus (1)
northwestern pond turtle, Clemmys marmorata marmorata (2.)
southwestern pond turtle, Clemmys marmorata pallida (1.)

Birds
ferruginous hawk, Buteo regalis (2*)
tricolored blackbird, Agelaius tricolor (2)
mountain plover, Charadrius montanus (2)
California horned lark, Eremophila alpestris actia (2)
loggerhead shrike, Lanius ludovicianus (2)
California black rail,Laterallus jamaicensis coturniculus (1)
Suisun song sparrow, Melospiza melodia maxillaris (2)
San Pablo song sparrow, Melospiza melodia samuelis (2)
salt marsh common yellowthroat, Geochlypis trichas sinuosa (2)

Mammals
San Pablo California vole, Microtus californicus sanpabloensis (2)
salt marsh vagrant shrew, Sorex vagrans halicoetes (1)
Pacific western big-eared bat, Plecotus townsendii townsendii (2)
greater western mastiff-bat, Eumops perotis californicus (2)
San Francisco dusky-footed woodrat, Neotoma fuscipes annectens (2)

Invertebrates
San Joaquin dune beetle, Coelus gracilis (1)
Ciervo aegialian scarab beetle, Aegialia concinna (1)
curved-foot hygrotus diving beetle, Hygrotus curvipes beetle (2)

Plants
Alameda manzanita, Arctostaphylos pallida (1)
Suisun aster, Aster chilertsis var. lentus (2)

heartscale, Atriplex. cordulata (2)
valley spearscale, Acriplex joaquiniana (2)
soft bird's-beak, Cordylanthus mollis ssp. mollis (l)
procumbent bird's-beak, Cordylanthus niduiarius (l)
interior California larkspur, Delphinium californicum ssp. interius (2)
recurved larkspur, Deiphinium recurvatum (2)
Contra Costa buckwheat, Eriogonum truncatum (2*)
diamond-petaled poppy, Eschscholzia rhombipetala (2)
fragrant fritillary, Fritillaria liliacea (2)
Diablo rock-rose, Heliartthella castanea (2)
Brewer's dwarf-flax, Hesperolinon breweri (2)
California hibiscus, Hibiscus californicus (2)
Santa Cruz tarweed, Holocarpha macradenia (l) -
Hinds' walnut, Juglans hindsii (2)
Contra Costa goldfields, Lasthenia conjugens (l)
delta tule-pea, Lathyrus jepsonii ssp. jepsonii (2)
Mason's lilaeopsis, Lilaeopsis masonii (2)
Mt. Diablo phacelia, Phacelia phacelioides (2)
rock sanicle, Sanicula saxatilis (2)
uncommon jewelflower, Streptanthus albidus ssp. peramoenus (1)
Mt. Diablo jewelflower, Streptanthus hispidus (2)
caper-fruited tropidocarpum, Tropidocarpum capparideum (2*)

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(E)- -Endangered (T)--Threatened (P)--Proposed (CH)--Critical Habitat
(1)- -Category 1: Taxa for which the Fish and Wildlife Service has sufficient biological information to support a proposal to list as endangered or threatened.
(2)- -Category 2: Taxa for which existing information indicated may warrant listing, but for which substantial biological information to support a proposed rule is lacking.
(1R) -Recommended for Category 1 status.
(2R) -Recommended for Category 2 Status.
(.â)- -Listing petitioned.
(*)- .Possibly extinct.

D29

ENCLOSURE No. 3

D30

United States Department of the Interior
FISH AND WILDLIFE SERVICE :
` FISH AND WILDLIFE ENHANCEMENT
VENTURA FIELD OFFICE
2140 Eastman Avenue, Suite 100

Ventura, California 93003

December 24, 1992

memorandum

To: Assistant Regional Director-Fish and wildlife Enhancement
Fish and wildlife Service, Portland, oregon
Attention: John Nuns

From: Acting Field supervisor, Ventura Field office
Ventura, California

Subject: species List for Bonneville Power Administration's proposed Intertie Project

As reguested in your November 27, 1992 memorandum, we are supplying you with a
species list for Bonneville Power Administration's (Bonneville) Service Area for the power plants of Morro Bay 1-4 in San Luis obispo County1 California- and Moss Landing 4, 5, and 7 in Monterey County, California. This species list includes all threatened and endangered species Including those administered by the National Marine Fisheries Service. (See attachment.)

Upon checking with Ms. Yvonne Johnson of Bonneville Power Administration and Mr. Craig walton of Pacific Gas and Electric, we have concluded that Bonneville is reguesting a species list for the operation and maintenance of these facilities. Consequently, this species list includes not only the location of the power plant, but also the facilities' used to transport the fuel source to these specific power plants. For the-Morro Bay and Moss Landing facilities, the primary fuel source is natural gas transported in a pipeline across the coastal ranges from the western San Joaquin Valley. The secondary fuel source is fuel oil transported by ship from any location in California.

we suggest that you notify Bonneville of two special management areas near the
Moss Landing powerplant: Elkhorn slough National Estuarine Research Reserve and Monterey Bay National Marine Sanctuary.

If you have any questions regarding this species list, please feel free to contact Ms. Judy Hohman of my staff at (805) 644-1766.

Attachments

LISTED AND PROPOSED ENDANGERED AND THReaTENED SPECIES
AND CANDIDATE SPECIES
BONNEVILLE POWER ADMINISTRATI0N INTERTIE PROGRAM

POWER PLANTS AND FUEL DELIVERIES FOR
M0SS LANDING, MONTEREY COUNTY, CALIFORNIA
AND M0RR0 BAY, SAN LUIS 0BISPO COUNTY, CALIFORNIA

LISTED SPECIES

Mammals

Southern sea otter	Enhydra lutris nereis	(T)
Morro Bay kangaroo rat	Dipodomys heermanni morroensis	(E)
*Stellar sea lion	Eumetopias jubatus	(T)
*Blue whale	Balaenoptera musculus	(E)
*Bowhead whale	Balaena mysticetus	(E)
*Finback whale	Balaenoptera physalus	(E)
*Gray whale	Eschrichtius robustus	(E)
*Hump-backed whale	Megaptera novaeangliae	(E)
*Right whale	Balaena glacialis	(E)
*Sei whale	Balaenoptera borealis	(E)
*sperm while.	Physeter catodon	(E)

Birds

California condor	Gymnogyps californianus	(E)
Bald eagle	Haliaeetus leucocephalus	(E)
Peregrine falcon	Falco peregrinus anatum	(E)
Marbled murrelet	Brachyrampus marmoratus marmoratus	(T)
California brown pelican	Pelecanus occidentalis californianus	(E)
California clipper rail,	Rallus longirostris obsoletus	(E)
Light-footed clipper rail	Rallus longirostris levipes	(E)
California least tern	Sterna antillarum browni	(E)

Reptiles

*Green sea turtle	Chelonia mydas	(E)
*Leatherback sea turtle	Dermochelys	(E)
*Loggernead sea turtle	caretta caretta	(T)
*olive Ridley sea turtle	Leuidochelys olivacea	(E)

Amphibians

Santa Cruz: long-toed salwander	Ambystoma macrodactylum croceum	(E)

Fishes

Unarmored threespine stickleback	Gasterosteus aculeatus williamsoni	(E)

Insects

Smith's blue butterfly	Euphilotes enoptes smithi	(E)

PROPOSED SPECIES

Birds

western snowy plover	Charadrius alexandrinus nivosus	(PT)

Fishes

Tidewater goby	Eucyclogobius newberryi	(PI)
Delta smelt	Hyppomesus transpacificus	(PT)

Snails

Morro shoulderband snail	Helminthoglyota walkeriana	(PE)

Plants

Morro mansanita	Arctostaphylos morroensis	(PE)
Chorro Creek bog thistle	Cirsium fontinale var. obispoense	(PE)
Pismo clarkia	Clarkia spciosa var. immaculata	(PE)
Indian Knob mountainbalm	Eriodictylon altissimum	(PE)
California Sea-blite	suaeda californica	(PE)
Mensies' wallflower	Erysimum menziesii	(PE)
Monterey gilia	Gilia tenuiflora	(PE)
Beach layia	Layia carnosa	(PE)
Clover lupine	Lupinus tidestromii	(PE)
Monterey spineflower	Chorizanthe pungens var. pungens	(PE)
Robust spineflower	chorizanthe robusta var. robusta	(PE)
Gamble's watercress	Roroppa gambellii	(PE)
Marsh sandwort	Arenaria paludicola	(PE)

CANDIDATE SPECIES

Mammals

ornate salt marsh shrew	Sorex ornatus salicornicus	(2)
southern marsh harvest mouse	Reithrodontomys megalotis limicola	(2)
Santa Cruz harvest mouse	Reithrodontomys megalotis sanatcruzae	(2)
Anacapa deer mouse	Peromyscus maniculatus anacanae	(2)

Birds

white-faced ibis	Plegadis chichi	(2)
California black rail	Laterallus iamaicensis coturniculus	(1)

Elegant tern	Sterna elegans	(2)
Long-billed curlew	Numenius americanus	(2)
Belding's savannah sparrow	passerculus sandwichensis beldingi	(2)
Large-billed savannah sparrow	Passerculus sandwichensis rostratus	(2)

Reptiles

southwestern pond turtle	Clemmys marmorata pallida	(2)
Black California legless lizard	Anniella pulchra nigra	(2)

Amphibians

California red-legged frog	Rana aurora draytoni	(2)

Beatles

Santa Cruz Island shore weevil	Trigonoscuta stantoni	(2)
white sand bear scarab beetle	Lichnanthe albonilosa	(2)
Globose dune beetle	Coelus globosus	(2)

Butterflies and Moths

Salt march skipper	Panoquina errans	(2)
Morro Bay blue butterfly	Icaricia icarioides moroensis	(2)
Oso Flaco patch butterfly	Chlosyne leanira osoflaco	(2)

snails

Mimic tryonia	Tyronia imitator	(2)

Plants

Coulter's seaside daisy	Lasthenia glabrata var. coulteri	(2)
Nuttall's lotus	Lotus nuttallianus	(2)
La Graciosa thistle	Cirsium loncholepis	(1)
Compact cobweb thistle	Cirsium occidentale var. compactum	(2)
Surf thistle	Cirsium rhothonhvlum	(1)
Del Mar Mesa sand aster	Corethrogyne filaginifolia var. linifolia	(2)
San Diego marsh elder	Iva havesiana	(2)
San Luis obispo curly-leaved monardella	Monardella undulata var. frutescens	(2)
Dune larkspur	Delphinium Darrvi spp. blochmaniae	(2)
Seaside bird's beak	Cordylanthus rigidus spp. littoralis	(1)
Jones' layia	Layia jonesii	(2)

Blair's munzothamnus	Munzothamnus blairii	(2)
Nipomo Mesa lupine	Lupinus nipomensis	(1)
Crisp Monardella	Monardella crispa	

*National Marine Fisheries Service has responsibilities for these species

Figure (Page D36 ELKHORN ...)

ELKHORN SLOUGH NATIONAL ESTUARINE RESeaRCH RESERVE

Welcome to California's first National Estuanne Reserve. We hope you enjoy your visit. Help us maintain the Reserve's resources and the safety of its visitors by following the regulations listed below

RULES FOR USE:

A. Only foot traffic is allowed on trails. Please remain on designated trails
B. Smoking is not allowed on the trails
C. All plants, animals and artifacts are protected. No collecting is allowed
D. Releasing of any animals, feeding of wildlife or introduction of any plant is prohibited
E. No pets are allowed on the Reserve
F. Fires, camping, boating and firearms are not permitted
G. Picnic only in designated area.
H. Please put litter in trash cans.
I. Researches have established experiments around the Reserve. Please do not remove or disturb any stakes or plots, or disrupt experiments in any way.
J. Enter Reserve only during, the posted OPEN hours and only through the main entrance.(1700 Elkhorn Rd.)

Figure (Page D37 ELKHORN SLOUGH...)

ELKHORN SLOUGH NATIONAL ESTUARINE RESeaRCH RESERVE

Nearly 90 percent of the estuarine and coastal marshes of California have been destroyed since the middle of the last century. Fortunately, we've begun to learn a great deal about these coastal habitats. Wetlands and marshes are extremely productive habitats that support tremendous members of fishes and other wildlife. Additionally, people derive great recreational, scientific, educational, and commercial benefit from this productivity.

Elkhorn Slough

Elkhorn Slough is one of the few relatively undisturbed coastal wetlands remaining in California. The main channel of the slough winds inland nearly seven miles and encompasses over 2,500 acres of marsh and tidal flats. Over 400 species of invertebrates, 80 species of fish, and 200 species of birds have been identified in Elkhorn Slough. The channels and tidal creeks of the slough are nurseries for many species of fish. Additionly, the slough is on the pacific flyway, providing a important feeding and resting ground for many kinds of migrating waterfowl and shorebirds. At least six rare, threatened or endangered species utilize the slough and environs, including peregrine falcons. Santa Cruz long-toed salamander, clapper rails, brown pelicans, least terns, and sea otters.

Federal and State Programs at Elkhorn slough National Estuarine Research Reserve

The 1,400-acre Elkhorn Slough National Research Reserve is managed by the California Department of Fish and Game in partnership with NOAA (Nationa Oceanic and Atmospheric Administration.) Programs on the Reserve and around the slough are also supported by Elkhorn Slough Foundation, a non-profit membership-supported organization.

The National program provides finacial assistance to coastal state for acquiring, developing, and operating valuable and unique estuarines and wetlands. The Reserves are natural field laboratories for long term scientific research and education program. Establishment of a Reserve protects vital habitats for wetland-dependent life and insures that scientists and the public can learn about coastal and estuarine ecology in a natural setting.

The Reserve is also a part of a state syste, the California Wildlands Program, established by the Department of fish and Game in 1988. The goals of this program are statewide habitat conservation for our native wildlife, and public education and interpretive services. This area is also a California Ecological Reserve.

TRAIL MAP

Reserve trails will lead you through a variety of habitats around the slough including oak woodland, grassland, and coastal saltmarsh. This map is provided to guide you during your visit. Please follow the simple Reserve regulation listed.

ENCLOSURE No. 4

United States Department of the Interio
FISH AND WILDLIFE SERVICE

Boise Field Station
4696 Overland Roadâ Room 576
Boise, Idaho 83705

December 14, 1992

Memorandum

To: Assistant Regional Director-Fish and Wildlife Enhancement, Portland, Oregon

Prom: Field Supervisor, Fish and Wildlife Enhancement, Boise, Idaho

Subject: BPA's Reguest' for List of Endangered and Threatened Species and Other Information for inclusion in BPA Service Area Non-Federal Participation Draft Environmental Impact Statement (1-4-93-SP-72/501. 1450)

Enclosed (Enclosure 1) is the reguested species list and comments.

Charles H. Lobdell

Enclosure

RECEIVED
DEC 17 1992,
US FISH & WILDLIFE SERVICE
REG1 FWE PORTLAND OR

D39

Enclosure 1

AS REQUESTED
LISTED AND PROPOSED ENDANGERED
AND THReaTENED SPECIES, AND CANDIDATE
SPECIES, TMAT OCCCR WITHIN THE STATE OF IDAHO

DATE: December 14, 1992
PROJECT NAME: Bonneville Power Administration Non-Federal Participation eis
SPECIES LIST NO. FWS 1-4-93-SP-72/501.l450

LISTED SPECIES	COMMENTS
Grizzly Bear	

(Ursus arctos horribilis)

Selkirk Mountain Woodland Caribou
(Rangifer tarandus caribou)

Gray Wolf
(Canis lupus)

Bald Eagle
(Haliaeetus leucocephalus)

Whooping Crane
(Grus americana)

Peregrine Falcon
(Falco peregrinus anatum)

Chinook Salmon (Spring/Summer and Fall Snake River run)
(Oncorhynchus tshawytscha)

Sockeye Salmon (Snake River)
(Oncorhynchus nerka)

MacFarlaneøs Four-O'Clock
(Mirabilis macfarlanei)

Banbury Springs Limpet (Lanx n. spp)	Occurs in the Minidoka Project
Bliss Rapids Snail (undescribed species)	Occurs in the Minidoka Project
Idaho Spring Snail (Pyrgulopsis idahoensis)	Occurs in the Minidoka Project

Snake River Physa Snail (Physa natriina)	Occurs in the Minidoka Project
Utah Valvata Snail (Valvata utahensis)	Occurs in the Minidoka Project

PROPOSED SPECIES

Bruneau Not Spring snail (PE)
(Pyrgulopsis bruneauensis)

CANDIDATE SPECIES

None

D41

ENCLOSURE No.5

D42

United States Departrrient of the Interior
FISH AND WILDLIFE SERVICE
FISH AND WILDLIFE ENHANCEMENT
RENO FIELD OFFICE
4600 Kietzke Lane, Building C-125
Reno, Nevada 89502-5093

December 18, 1992
File No. 1-5-93-SP-66
1-5-93-5P-83

Memorandum

To: Assistant Regional Director, Fish and Wildlife Enhancement,
Portland, Oregon (AFWE-EHC)

From: Field Supervisor, Reno Field Office, Reno, Nevada

Subject: Reguest for Species List, Bonneville Power Administration (BPA)
; Projects at Valmy and Laughlin, Nevada (Your Memo, November 27,
1992)

As reguested by your memorandum dated November 27, 1992, we have attached a
- list of endangered, threatened, and candidate species that may occur in the
area of the Bonneville Power Administration projects at Valmy and Laughlin,
Nevada.

Please contact Robin Hamlin at (702) 784-5227 if you have questions regarding
this list.

David L. Harlow

Attachments

DEC 28 1992

ATTACHMENT A

LISTED ENDANGERED SPECIES AND
CANDIDATE SPECIES THAT MAY OCCCR IN THE ARea OF THE
Bonneville Power Administration (BPA) Project at
Valmy, Nevada

File Nubber: 1-5-93-SP-66

Candidate Species

Mammals	
2 pygmy rabbit	Brachylagus idahoensis
2 spotted bat	Euderma maculatum
Birds	
2 ferruginous hawk	Buteo regalis
2 black tern	Chlidonias niger
2 western least bittern	Ixobrychus exilis hesperis
2 loggerhead shrike	Lanius ludovicianus
2 white-faced ibis	Plegadis chihi
Invertebrates	
2 Nevada viceroy	Limenitus archippus lahontani

(2) --Category 2: Taxa for which existing information indicates may warrant listing, but for which substantial biological information to support a proposed rule is lacking.

ATTACHMENT A

LISTED ENDANGERED SPECIES AND
CANDIDATE SPECIES THAT MAY OCCUR IN THE AREa OF THE

Bonneville Power Administration (SPA) Project at
Laughlin, Nevada

File Number: 1-5-93-SP-83

Listed Species

Birds	
E bald eagle	Haliaeetus leucocephalus
E American pregrine falcon	Falco peregrinus anatum
Fishes	
E bonytail chub	Gila elegans
E razorback sucker	Xyrauchen texanus
Reptiles	
T desert tortoise	Gopherus agassizii

E--Endangered

Candidate Species

mammals	
2 spotted bat	Euderma maculatum
Birds	
2 black tern	Chlidonias niger
2 western least bittern	Ixobrychus exilis hesperis
2 loggerhead shrike	Lanius ludovicianus
2 white-faced ibis	Plegadis Chihi
Reptiles	
2 chuckwalla	Sauromalus obesus

(2)--Category 2: Taxa for which existing information indicates way warrant listing, but for which substantial biological information to support a proposed rule is lacking.

ENCLOSURE No. 6

D46

United States Department of the Interior
FISH AND WILDLIFE SERVICE
Portland Field Station
2600 S.E. 98th Avenue, Suit 100
Portland, Oregon 97266

December 24, 1992

Memorandum

To: Assistant Regional Director, âFish and Wildlife Enhancement, Portland, Oregon
Attn: John Nuss

From: Field supervisor, Portland Field Office, Portland, Oregon

subject: Bonneville Power Administration (SPA) Service Area Non-Federal Participation (NFP) Environmental Impact StateRent (eis)
Ref: 1-7-93-TA-116

This is in response to your memorandum dated Decebbeâr 2, 1992, requesting assistance in preparing a species list for SPA's NFP eis. We have attached a list (Attachment A) of threatened and endangered (TOE) species occurring in the vicinity of the utilities and hydroelectric dams proposed as alternatives. At this time there are no specific recorded occurrences of TOE species in the vicinity of the Boardman plant, Trojan Nuclear plant, McNary Dam, The âDalles Dam, or the John Day Dam.

We have one correction for the list of T&E species provided by the Regional Office. The marbled murrelet is designated as threatened, not endangered.

If you have further questions please contact Diane Sotâak at 231-6179.

Attachment

cc: PFO-ES

RECEIVED

DEC 29 1992

DS/lc/TA116FWS.MEM

US FISH & WILDLIFE SERVICE

REG 1 FWE PORTLAND, OR

D47

ATTACHMENT A

LISTED AND PROPOSED ENDANGERED AND THReaTENED SPECIES
THAT MAY OCCUR IN THE BONNEVILLE POWER ADMINISTRATION
SERVICE ARea
1-7-93-TA-116

Bonneville
Bald eagle-1/ Haliaeetus leucocephalus T
Recorded occurrence: T2N R7E Sec. 28

Detroit/Big Cliff
Bald eagle Haliaeetus leucocephalus T
Recorded occurrence: T10S R5E Sec. 7, 16
Recorded nest size: T1OS R5E Sec. 20
Northern spotted owl-2/ Stcix occidentalis caurina CH T
Recorded occurrence: T10S R5E Sec. 33
Lookout Point/Dexter
Bald eagle Haliaeetus leucocephalus T
Recorded occurrence: T19S R1W Sec. 16
Recorded nest site: T19S RlW Sec. 24
Northern spotted owl.ââ Strix occidentalis caurina CH T
Records occurrence: T19S R1E Sec. 3
Oregon chub-3/ Oregonichthys (=Hybopsis) crameri PE
Recorded occurrence: T19S RlE Sec. 30
T19S R1W Sec. 15

Hills Creek
Bald eagle Haliaeetus leucocephalus T
Recorded occurrence: T21S R3E Sec. 26, 27
Northern spotted owl Strix occidental is caurina CH T
Gray wolf-4/ Canis lupus E
Historic occurrence: T21S R3E Sec. 21
Oregon chub Oregonichthys (=Hybopsis) crameri PE
Recorded occurrence: T21S R3E Sec. 35

Couqar

Bald eagle Haliaeetus leucocephalus
T
Recorded occurrence: T17S R5E Sec. 6
Northern spotted owl Strix occidentalis caurina CH
T
Gray wolf Canis lupus
Historic occurrence: T16S R5E Sec. 11

Foster/Green Peter
Bald eagle Haliaeetus leucocephalus
T
Recorded nest site: T13S R5E Sec. 25, 26
Northern spotted owl Strix occidentalis caurina CH
T
Gray wolf Canis lupus
E
Historic occurrence: T13S R1E Sec. 22
T13S R2E Sec. 16

Lost Creek
Bald eagle Haliaeetus leucocephalus
T
Recorded occurrence: T33S R1E Sec. 4, 27
T33S R2E Sec. 31
Northern spotted owl Strix occidentalis caurina CH
T
Recorded occurrence: T33S R2E Sec. 15

(E) - Endangered IT) - Threatened (CH) - Critical Habitat
(PE) - Petitioned Endangered

1/ U. S. Department of Interior1 Fish and Wildlife Service, July 15, 1991, Endangered and Threatened Wildlife and Plants, 50 CFR 17.11 and 17.12.
2/ Federal Register Vol. 57, No. 10, January 15, 1992, Final Rule-Critiâcal~ Habitat for the Northern Spotted Owl
3/ Federal Register Vol. 56, No. 224, November 19, 1991, Proposed Rule-Oregon chub
4/ Federal Register Vol. 56, No. 225, November 21, 1991, Notice of Review-Animals

United States Department of the Interior
FISH AND WILDLIFE SERVICE

911 NE. 11th Avenue
Portland Oregon 97232-4181

November 20, 1992

Maureen R. Flynn, Project Manager
Non-Federal Participation eis
Coordination and Review
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

Dear Ms. Flynn:

This is in response to your October 21, 1992, letter (reply reference "PGA"), received October 23,. 1992, requesting a compilation of federally listed endangered and threatened species that may occur in the Bonneville Power Administration's (BPA) service area inclusive of California, Idaho, Montana, Nevada, Oregon, Utah, and Wyoming. You also requested:

1. Any information about these species, such as locations, and how these species might be affected by alternatives for use of BPA's share of the Pacific Northwest-Pacific Southwest Intertie.

2. A list of contacts at the Fish and Wildlife Service's (Service) Region l field office level.

Our office has compiled a general listing of federally listed and proposed endangered and threatened species that may occur in California, Idaho, Nevada, Oregon, and Washington. It will be necessary for you to contact the Service's Regional Office in Region 6 for a list of species that may occur in Montana, Utah, and Wyoming. The address and contact person for Region 6 is:

Mr. Jim lutey
Chief of Federal Activities and Special Projects
Fish and Wildlife Enhancement
U.S. Fish and Wildlife Service
P.O. Box 25486
Denver, Colorado 80225
Telephone: (303) 236-8186

We will contact our field offices to request that they prepare the species lists that you require relative to site-specific actions. Upon our receipt of the' lists, we will collate them and forward the information to you. However, in order for us to provide you with this information, our field office staffs will need specific data on BPA's action including project site-specific locations, facilities descriptions and proposed activities. Please send an information package to this office and each of our field offices listed below.

We will notify the field office staffs that the appropriate data will be forthcoming from your office.

To obtain specific information about the biology and life requirements of each endangered and threatened species that may occur in Region.1, please contact the following field offices and individuals directly:

California
Mr. Wayne White
Field Supervisor, Sacramento Field-Office
Fish and Wildlife Enhancement
U.S. Fish and Wildlife Service
2800 Cottage Way, E-1823 & 1803
Sacramento, California 95825
Telephone: (916) 978-4613

Mr. John Ford
Field Supervisor, Ventura Field Office
Fish and Wildlife Enhancement
U.S. Fish and Wildlife Service
2140 Eastman Avenue, Suite 100
Ventura, California 93003
Telephone: (805) 644-1766

Mr. Jeff Opdycke
Field Supervisor, Carlsbad Field' Office
Fish and Wildlife Enhancement
U.S. Fish and Wildlife Service
2730 loker Avenue West
Carlsbad, California 92008
Telephone: (619) 431-9440

Idaho
Mr. Charles Lobdell
Field Supervisor, Boise Field Office
Fish and Wildlife Enhancement
U.S. Fish and Wildlife Service
4696 Overland Road, Room 576
Boise, Idaho 83705
Telephone: (208) 334-1931

Nevada
Mr. David Harlow
Field Supervisor, Reno Field Station
Fish and Wildlife Enhancement
U.S. Fish and Wildlife Service

4600 Kietzke Lane, Bldg. C-125
Reno, Nevada 89502
Telephone: (702) 784-5227

Oregon
Mr. Russell Peterson
Field Supervisor, Portland Field Office
Fish and Wildlife Enhancement
U.S. Fish and Wildlife Service
2600 S.E. 98th Avenue, Suite 100
Portland, Oregon 97266
Telephone: (503) 231-6179

Washington
Mr. Dave Frederick
Field Supervisor, Olympia Field Office
Fish and Wildlife Enhancement
U.S. Fish and Wildlife Service
3704 Griffin Lane S~.E., Suite 102
Olympia.-Washington 98501-2192
Telephone: (206) 753-9440

Your interest in endangered species is appreciated. If you have any questions please contact John Nuss at our office, phone (503) 231-6151.

Sincerely,

H. Dale Hall
Assistant Regional Director
Fish and Wildlife Enhancement

Federally Listed and Proposed Endangered and Threatened
Species of California

Status	Group Name	Common Name	Scientific Name	critical Habitat
E	Mammals	Beaver, Point Arena mountain	Aplodontia rufa nigra	
E	Mammals	Fox, San Joaquin kit	Vulpes macrotis mutica	

E Mammals Mouse, Salt marsh harvest Reithrodontomys
raviventris
T Mammals Otter, Southern sea Enhydra lutris
nereis
E Mammals Rat, Fresno kangaroo Dipodomys
nitratoides exilis CH
E Mammals Rat, Giant kangaroo Dipodomys ingens
E Mammals Rat, Morro Bay kangaroo Dipodomys
heermanni morroensis CH
E Mammals Rat, Stephens' kangaroo Dipodomys
stephensi
E Mammals Rat, Tip ton kangaroo Dipodomys
nitratoides
nitratoides
T Mammals Sea lion, Steller Eumetopias jubatus
T Mammals Seal, Guadalupe fur Arctocephalis
townsendi
PE Mammals Sheep, Peninsular bighorn Ovis canadensis
cremnobates
(Population listing)
E Mammals Vole, Amargosa Microtus
californicus CH
E scirpensis
E Mammals Whale, Blue Balaenoptera
musculus
E Mammals Whale, Bowhead Balaena mysticetus
E Mammals Whale, Finback Balaenoptera
physalus
E Mammals Whale, Gray Eschrichtius
robustus
E Mammals Whale, Hump-backed Megaptera-
novaeangliae
E Mammals Whale, Right Balaena glacialis
E Mammals Whale, Sei Balaenoptera
borealis
E Mammals Whale, Sperm Physeter catodon
E Birds Condor, California Gymnogyps
californianus CH
E Birds Eagle, Bald Haliaeetus
leucocephalus
E Birds Falcon, American peregrine Falco peregrinus
anatum CH
T Birds Falcon, Arctic peregrine Falco peregrinus
tundrius
PE Birds Gnatcatcher, California coastal Polioptila
californica ssp
californica
E Birds Goose, Aleutian Canada Branta canadens is
leucopareia

Califâornia Species

Status Group Name Common Name Scientific Name
Critical Habitat

E	Birds	Murrelet, Marbled	Brachyramphus marmoratus	
T	Birds	Owl, Northern spotted	Strix occidentalis caurina	CH
E	Birds	Pelican, California brown	Pelecanus occidentalis californianus	
PT	Birds	Plover, Western snowy (coastal population	Charadrius alexandrinus nivosus	
E	Birds	Rail, California clapper	Rallus longirostris obsoletus	
E	Birds	Rail, Light-footed clapper	Rallus longirostris levipes	
E	Birds	Rail, Yuma clapper	Rallus longirostris yumanensis	
E	Birds	Shrike, San Clemente loggerhead	Lanius ludovicianus mearnsi	
T	Birds	Sparrow, San Clemente sage	Amphispiza belli clementeae	
E	Birds	Tern, California least	Sterna antillarum browni	
T	Birds	Towhee, Inyo brown	Pipilo fuscus eremophilus	CH
E	Birds	Vireo, Least Bell's	Vireo bellii pusillus	
E	Reptiles	Lizard, Blunt-nosed leopard	Gambelia silus	
T	Reptiles	Lizard, Coachella Valley fringe-toed	Uma inornata	CH
T	Reptiles	Lizard, island night	Xantusia riversiana	
E	Reptiles	Snake, San Francisco garter	Thamnophis sirtalis tetrataenia	
PE	Reptiles	Snake, giant garter	Thamnophis gigas	
T	Reptiles	Tortoise, Desert	Gopherus agassizii	
T	Reptiles	Turtle, Green sea	Chelonia mydas	
E	Reptiles	Turtle, Leatherback sea	Dermochelys coriacea	
E	Reptiles	Turtle, Loggerhead sea	Caretta caretta	
E	Amphibians	Salamander, Desert slender	Batrachoseps aridus	
E	Amphibians	Salamander, Santa Cruz long-toed	Ambystoma macrodactylum croceum	
E	Fishes	Chub, Bonytail	Gila elegans	
E	Fishes	Chub, Mohave tui	Gila bicolor mohavensis	
E	Fishes	Chub, Owens tui	Gila bicolor snyderi	CH
E	Fishes	Pupfish, Desert	Cyprinodon macularius	CH
E	Fishes	Pupfish, Owens	Cyprinodon radiosus	

California Species

Status	Group Name	Common Name	Scientific Name	Critical Habitat
T	Fishes	Salmon, Chinook (Winter run Sacramento River)	Oncorhynchus tshawytscha	CH
PE	Fishes	Smelt, delta	Hyppomesus transpacificus	
E	Fishes	Squawfish, Colorado	Ptychocheilus lucius	
E	Fishes	Stickleback, Unarmored threespine	Gasterosteus aculeatus williamsoni	
E	Fishes	Sucker, Lost River	Deltistes luxatus	
E	Fishes	Sucker, Modoc	Catostomus microps	CH
E	Fishes	Sucker, Razorback	Xyrauchen texanus	
E	Fishes	Sucker, Shortnose-	Chasmistes brevirostris	
T	Fishes	Trout, Lahontan cutthroat	Salmo clarki henshawi	
T	Fishes	Trout, Little Kern golden	Salmo aguabonita whitei	CH
T	Fishes	Trout, Paiute cutthroat	Salmo clarki seleniris	
PE	Snails	Snail, Morro shoulderband	Helminthoglypta walkeriana	
E	Crustaceans	Crayfish, Shasta	Pacifastacus fortis	
PE	Crustaceans	Linderiella, California	Linderiella occidentalis	
E	Crustaceans	Shrimp, California freshwater	Syncarjs pacifica	
PE	Crustaceans	Shrimp, Conservancy fairy	Branchinecta conservatio	
PE	Crustaceans	Shrimp, Longhorn fairy	Branchinecta longiantenna	
PE	Crustaceans	Shrimp, Riverside fairy	âstreptocephalus woottoni	
PE	Crustaceans	Shrimp, Vernal pool fairy	Branchinecta lynchi	
PE	Crustaceans	Shrimp, Vernal pool tadpol	Lepidurus packardi	
T	insects	Beetle, Delta green ground	Elaphrus viridis	CH
T	Insects	Beetle, Valley elderberry longhorn	Desmocerus californicus dimorphus	CH
T	Insects	Butterfly, Bay checkerspot	Euphydryas editha bayensis	
E	Insects	Butterfly, œl.Segundo blue	œuphilotes battoides allyni	

E	insects	Butterfly, Lange's metalmark	Apodemia mormo langei	
E	Insects	Butterfly, Lotis blue	Lycaeides argyrognomon lot is	
E	Insects	Butterfly, Mission blue	Icaricia icarioides missionensis	
E	insects	Butterfly, Myrtle's silverspot	Speyeria zerenemyrtleae	
T	Insects	Butterfly, Oregon silverspot	Speyeria zerene hippolyta	CH

Status	Group Name	Common Name	Scientific Name	Critical Habitat
E	Insects	Butterfly, Palos Verdes blue	Glaucopsyche lygdamus palosverdesensis	CH
E	Insects	Butterfly, San Bruno elfin	Callophrys mossii bayensis	
E	Insects	Butterfly, Smith's blue	Euphilotes enoptes smithi	
T	Insects	Moth, Kern primrose sphinx	Euproserpinus euterpe	
E	Plants	Barberry, Truckee	Mahonia sonnei	
E	Plants	Bird' s-beak, Palmate -bracted	Cordylanthus âpalmatus	
E	Plants	Bird's-beak, Salt marsh	Cordylanthus maritimus ssp maritimus	
E	Plants	Bush-mallow, San Clemente	Island clementinus	
PE	Plants	Button-celery, San Diego	Eryngium- aristulatum var. parishii	
E	Plants	Cactus, Bakersfield	Opuntia trealeasei	
T	Plants	Centaury-plant, Spring-loving	Centaurium namophilum	CH
E	Plants	Checker-mallow, ,Pedate	Sidalcea pedata	
PE	Plants	Clarkia, Pismo -	Clarkia speciosa ssp. immaculata	
E	Plants	Cypress, Santa Cruz	Cupressus abramsiana	
E	Plants	Evening~primrose, Antioch Dunes	Oenothera deltoides ssp howellii	CH
E	Plants	Evening-primrose, Eureka Valley	Oenothera avita ssp eurekensis	
T	Plants	Evening~primrose, San Benito	Camissonia benitensis	
E	Plants	Fiddleneck, Large-flowered	Amsinckia grandiflora	CH

E	Plants	Gilia, - Monterey	Gilia tenuiflora 55p. arenaria	
E	Plants	Goldfields, Burke's	Lasthenia burkei	
E	Plants	Grass, Eureka Valley dune	Swallenia alexandrae	
E	Plants	Grass, Solano	Tuctoria mucronata	
T	Plants	Gum-weed, Ash Meadows (Western G.)	Grindelia fraxiflo~pratensis	CH
E	Plants	Indian-paintbrush, San Clemente Island	Castilleja grisea	
E	Plants	jewelflower, California	Caulanthus californicus	

Status	Group Name	Common Name	Scientific Name	Critical Habitat
E	Plants	Larkspur, San Clemente Island	Delphinium kinkiense	
E	Plants	Live-forever, Santa Barbara Island	Dudleya traskiae	
E	Plants	Lupine, Point Reyes	Lupinus tidestromii var. layneae	
E	Plants	Mallow, Kern	Eremalche kernensis	
PE	Plants	Manzanita, Morro	Arctostaphylos morroensis	
E	Plants	Manzanita, Presidio	Arctostaphylos pungens var. ravenii	
E	Plants	Meadow-foam, Butte County	Limnanthes floccosa ssp. californica	
E	Plants	Meadow-foam, Sebastopol	Limnanthes vinculans	
PE	Plants	Mesa mint, Otay (Loma Alta M.)	Pogogyne nudiuscula	
E	Plants	Mesa mint, San Diego	Pogogyne abramsii	
PE	Plants	Milk-vetch, Coachella Valley	Astragalus lentiginosus var. coachellae	
PE	Plants	Milk-vetch, Fish Slough	Astragalus lentiginosus var. piscinensis	
PE	Plants	Milk-vetch, Lane Mountain	Astragalus jaegerianus	
PE	Plants	Milk-vetch, Peirson's	Astragalus magdalenae var.	

peirsonii
PT Plants Milk-vetch, Shining Astragalus
lentiginosus var.

micans
PT Plants Milk-vetch, Sodaville Astragalus
lentiginosus var.

sesquimetralis
PE Plants Milk-vetch, Triple-ribbed Astragalus
tricarinatus
E Plants Nitervort, Amargosa (Mojave Nitrophila
mohavensis CH
Borax-weed)
PE Plants Orcutt-grass, California Orcuttia
californica
E Plants Rock-cress, McDonald's Arab is
mcdonaldiana
PE Plants Sandwort, Marsh Arenaria
paludicola
PE Plants Seepweed, California Suaeda californica

Status Group Name Common Name Scientific Name
Critical Habitat

PE Plants Spine flower, Ben Lomond Chorizanthe
pungens var.

hartwegiana
E Plants Spineflower, Howell's Chorizanthe
howellii
E Plants Spineflower, Monterey Chorizanthe
pungens var.

E Plants Spineflower, Robust Chorizanthe
robusta var.

robusta
E Plants Spineflower, Scotts Valley Chorizanthe
robusta var.

hartwegii
E Plants Spine flower, Slender-horned Dodecahema
leptoceras
E Plants Spine flower, Sonoma Chorizanthe
valida
E Plants Sticky-seed, Baker's Blennosperma
bakeri
E Plants Thelypody, Slender.petaled Thelypodium
stenopetalum
E Plants Thornmint, San Mateo Acanthomintha
obovata spp

duttonii
E Plants Tidytips, Beach Layia carnosa
E Plants Tree-foil, San Clemente Island Lotus
dendroideus ssp.

Status	Group Name	Common Name	Scientific Name	Critical Habitat
		broom	traskiae	
E	Plants	Wall-flower, Contra Costa	Erysimum capitatum var. angustatum	
E	Plants	Wall-flower, Menzies'	Erysimum menziesii	
T	Plants	Wooly-star, Hoover's	Eriastrum hooveri	
E	Plants'	Wooly-star, Santa Ana River	Eriastrum densifolium ssp sanctorum	
E	Plants	Wooly-threads, San Joaquin	Lembertia congdonii	
PE	Plants	Yellow-crass, Gambel's	Rorippa gambelii	
PE	Plants	Yerba-santa, Tall	œriodictyon altissimum	

Federally Listed and Proposed Endangered and Threatened Species of Idaho

Status	Group Name	Common Name	Scientific Name	Critical Habitat
T	Mammals	Bearâ, Grizzly	Ursus arctos	
E	Mammals	Caribou, Selkirk Mountain woodland	Rangifer tarandus caribou	
E	Mammals	Wolf, Gray	Canis lupus	
E	Birds	Crane, Whooping	Grus americana	CH
E	Birds	Eagle, Bald	Haliaeetus leucocephalus	
E	Birds	Falcon, American peregrine	Falco peregrinus anatum	CH
T	Fishes	Salmon, Chinook (Spring/Summer run Snake River)	Oncorhynchus tshawytscha	
E	Fishes	Salmon, Snake River sockeye	Oncorhynchus nerka	
T	Fishes	Salmon, chinook (Fall run Snake River)	Oncorhynchus tshawytscha	
E	Snails	Limpet, Banbury Springs	Lanx n. sp	
E	Snails	Snail,- Bliss rapids	Genus and species undescribed	
E	Snails	Snail, Bruneau hot spring	Genus and species undescribed	
E	Snails	Snail, Idaho spring	Pyrgulopsis idahoensis (=Fontelicella i.)	

PE	Snails	Snail, Snake River physa	Physa (undescribed species)
PE	Snails	Snail, Utah valvata	Valvata utahensis- -
E	Plants	Four-O'Clock, MacFarlane's	Mirabilis macfarlanei

Federally Listed and Proposed Endangered and Threatened Species of Nevada

Status	Group Name	Common Name	Scientific Name	Critical Habitat
E	Birds	Eagle, Bald	Haliaeetus leucocephalus	
E	Birds	Falcon, American peregrine	Falco peregrinus anatum	CH
E	Fishes	Chub, Bonytail	Gila elegans	
E	Fishes	Chub, Pahranagat roundtail	Gila robusta Jordani	
E	Fishes	Chub, Virginriver	Gila robusta seminuda	
E	Fishes	Cui-ui	Chasmistes cujus	
E	Fishes	Dace, Ash Meadows speckled	Rhinichthys osculus nevadensis	CH
E	Fishes	Dace, C!over Valley speckled	Rhinichthys osculus oligo	
T	Fishes	Dace, Desert	Eremichthys acros	CH
E	Fishes	Dace, Independence Valley speckled	Rhinichthys ogculus lethoporus	
E	Fishes	Dace, Moapa	Moapa coriaceae	
E	Fishes	Killifish, Pahrump	Empetrichthys latos latos	
E	Fishes	Pupfish, Ash Meadows Amargosa	Cyprinodon nevadensis mionectes	CH
E	Fishes	Pupfish, Devils Hole	âCyprinodon diabolis	
E	Fishes	Pup fish, Warm Springs	Cyprinodon nevadens is pectoralis	
T	Fishes	Spinedace, Big Spring	Lepidomeda mollispinis pratensis	CH
E	Fishes	Spinedace, White River	Lepidomeda albivallis	CH
E	Fishes	springfish, Hiko White River	Crenichthys baileyi grandis	CH
T	Fishes	springfish, Railroad Valley	Crenichthys nevadae	CH
E	Fishes	springfish, White River	Crenichthys baileyi baileyi	CH
E	Fishes	squawfish, Colorado	Ptychoche ilus luc ius	
E	Fishes	Sucker, Razorback	Xyrauchen texanus	

T	Fishes	Trout, Lahontan cutthroat	Salmo clarki henshawi	
E	Fishes	Woundfin,	Plagopterus argentissimus	
T	Reptiles	Tortoise, Desert	Gopherus agassizii	
T	Insects	Naucorid, Ash Meadows	Ambrysus amargosus	CH

Nevada Species

Status	Group Name	Common Name	Scientific Name	Critical Habitat
T	Plants	Blazing Star, Ash Meadows	Mentzelia leucophylla	CH
T	Plants	Centaury-plant, Spring-loving	Centaurium namophilum	CH
T	Plants	Gum-weed, Ash Meadows (Western G.)	Grindelia fraxindpratensis	CH
T	Plants	Ivesia, Ash Meadows (Kings I.)	Ivesia eremica	CH
T	Plants	Ladies-tresses, Ute	Spiranthes diluvialis	
T	Plants	Mjlk-vetch, Ash Meadows	Astragalus phoenix	CH
PT	Plants	Milk-vetch, Sodaville	Astragalus lentiginosus var. sesquimetralis	
E	Plants	Nitervort, Amargosa (Mojave Borax-weed)	Nitrophila mohavensis	CH
T	Plants	Sunray, Ash Meadows	Enceliopsis nudicaulis var corrugata	CH
E	Plants	Wild-buckwheat, Steamboat Springs	Eriogonum ovalifolium var. wi!liamsiae	

Federally Listed and Proposed Endangered and Threatened Species of Oregon

Status	Group Name	Common Name	Scientific Name	Critical Habitat
E	Mammals	Deer, Columbian white-tailed	Odocoileus virginianus leucurus	

T	Mammals	Sea lion, Steller	Eumetopias jubatus	
E	Mammals	Whale, Blue	Balaenoptera musculus	
E	Mammals	Whale, Bowhead	Balaena mysticetus	
E	Mammals	Whale, Finback	Balaenoptera physalus	
E	Mammals	Whale, Gray	Eschrichtius robustus	
E	Mammals	Whale, Hump-backed	Megaptera novaeangliae	
E	Mammals	Whale, Right	Balaena glacialis	
E	Mammals	Whale, Sei	Balaenoptera borealis	
E	Mammals	Whale, Sperm	Physeter catodon	
T	Birds	Eagle, Bald	Haliaeetus leucocephalus	
E	Birds	Fa!con, American peregrine	Falco peregrinus anatum	CH
T	Birds	Falcon, Arctic peregrine	Falco peregrinus tundrius	
T	Birds	Goose, Aleutian Canada	Branta canadensis leucopareia	
E	Birds	Murrelet, Marbled	Brachyramphus marmoratus	
T	Birds	Owl, Northern spotted	Strix occidentalis caurina	CH
E	Birds	Pelican, California brown	Pelecanus occidentalis californianus	
E	Birds	Plover, Western snowy (coastal population) .	Charadrius alexandrinus nivosus	
E	Reptiles	Turtle, Leatherback sea	Dermochelys coriacea	
E	Fishes	Chub, Borax Lake	Gila boraxobius	CH
T	Fishes	Chub, Hutton tui	Gila bicolor ssp	
T	Fishes	Dace, Foskett speckled	Rhinichthys osculus ssp	
T	Fishes	Salmon, Chinook (Spring/Summer run Snake River)	Oncorhynchus tshawytscha	
E	Fishes	Salmon, Snake River sockeye	Oncorhynchus nerka	
T	Fishes	Salmon, chinook (Fall run Snake River)	Oncorhynchus tshawytscha	

Oregon Species

Status	Group Name	Common Name	Scientific Name	Critical Habitat
E	Fishes	Sucker, Lost River	Deltistes luxatus	
E	Fishes	Sucker, Shortnose	Chasmistes brevirostris	
T	Fishes	Sucker, Warner	Catostomus warnerensis	CH
T	Insects	Butterfly, Oregon silverspot	Speyeria zerene hippolyta	CH
PE	Plants	Checker-mallow, Nelson's	Sidalcea nelsoniana	
E	Plants	Desert-parsley, Bradshaw's	Lomatium bradshawii	
E	Plants	Four-O'Clock, MacFarlane's	Mirabilis macfarlanei	
PE	Plants	Milk-vetch, Applegate's	Astragalus applegatei	
PE	Plants	Sandwort Marsh	Arenaria paludicola	
E	Plants	Skeletonplant, Malheur	Stephanomeria malheurensis	CH

Federally Listed and Proposed Endangered and Threatened

Species of Washington

Status	Group Name	Common Name	Scientific Name	Critical Habitat
T	Mammals	Bear, Grizzly	Ursus arctos	
E	Mammals	Caribou, Selkirk Mountain woodland	Rangifer tarandus caribou	
E	Mammals	Deer, Columbian white-tailed	Odocoileus virginianus leucurus	
T	Mammals	Sea lion, Steller	Eumetopias jubatus	
E	Mammals	Whale, Blue	Balaenoptera musculus	
E	Mammals	Whale, Bowhead	Balaena mysticetus	
E	Mammals	Whale, Finback	Balaenoptera physalus	
E	Mammals	Whale, Gray	Eschrichtius robustus	
E	Mammals	Whale, Hump-backed	Megaptera novaeangliae	
E	Mammals	Whale, Right	Balaena glacialis	
E	Mammals	Whale, Sei	Balaenoptera borealis	
E	Mammals	Whale, Sperm	Physeter catodon	
E	Mammals	wolf, Gray	Canis lupus	
T	Birds	Eagle, Bald	Haliaeetus leucocephalus	

E	Birds	Falcon, American peregrine	Falco peregrinus anatum	CH
T	Birds	Falcon, Arctic peregrine	Falco peregrinus tundrius	
T	Birds	Goose, Aleutian Canada	Branta canadensis leucopareia	
E	Birds	Murrelet, Marbled		
T	Birds	Owl, Northern spotted	Strix occidentalis caurina	CH
E	Birds	Pelican, California brown	Pelecanus occidental is californianus	
PT	Birds	Plover, ,Western snowy (coastal population)	Charadrius alexandrinus nivosus	
E	Reptiles	Turtle, Leatherback sea	Dermochelys coriacea	
T	Fishes	Salmon, Chinook (Spring/Summer run Snake River)	Oncorhynchus tshawytscha	
E	Fishes	Salmon, Snake River sockeye	Oncorhynchus nerka	
T	Fishes	Salmon, chinook (Fall run ` Snake River)	Oncorhynchus tshawytscha	
T	Insects	Butterfly, Oregon silverspot	Speyeria zerene hippolyta	CH
PE	Plants	Sandwort, Marsh	Arenaria paludicola	

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United States Department of the Interior
FISH AND WILDLIFE SERVICE
Post Office Box 1306
Albuquerque. N.M. 87103

In Reply Refer To:
R2/FWE-SE
CL 11-076

JAN 4 1993

2-1-93-1-01

Ms. Maureen R. Flynn
NFP eis Project Manager
Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

Dear Ms. Flynn:

This responds to your November 4,1992, letter requesting a list Of endangered and threatened species that may occur in Apache and Navajo - Counties, Arizona; and San Juan County, New Mexico. In our discussion with Yvonne Johnson of your staff on December 10, 1992, it was agreed that this response is due to you by January 15,1993.

In addition to the listed species, we are also including a list of proposed and candidate category 1 and 2 species. While proposed endangered and threatened species are addressed under section 7(a) (4) of the Endangered Species Act, as amended, the candidate species have no protection under this Act, but are included for planning purposes. Candidate category 1 species are those for which there is substantial information available to support their listing as endangered or threatened, and publication of proposed rules for these species is anticipated. Candidate category 2 species are those for which data on biological vulnerability and threats are not currently known to support the preparation of listing rules. In addition to the species list, l am enclosing information on some of these species.

Field station contacts for Arizona and New Mexico include:

Field Supervisor
Ecological Services Field Office
3616 W. Thomas Road, Suite 6
Phoenix, Arizona 85019
(602)379-4720

Field Supervisor
Ecological Services Field Office
3530 Pan American Hwy, Suite D
Albuquerque, New Mexico 87017
(505)883-7877

If you have any questions about this species list, please contact Gary Halvorson or Steve Helfert at (505)766-3972.

Sincerely,

Regional Director

Enclosures

cc: (w/enclosure)

Field Supervisors, Ecological Services, FWS, Arizona and New Mexico

State

Arizona

Apache County

Common Name	Scientific Name	Group*	Status**
Occult little brown bat	Myotis lucifugus occultus	M	C2
Silky pocket mouse	Perognathus flayus goodpasteri	M	62
Spotted bat	Euderma maculatum	M	62
Mexican gray wolf	Canis lupus baileyi	M	E
Bald eagle	Haliaeetus leucocephalus	B	E
American peregrine falcon	Falco peregrinus anatum	B	E
Mexican spotted owl	Strix occidentalis lucida	B	P
Northern goshawk	Accipiter gentilis	B	C2
Apache goshawk `	Accipiter gentilis apache	B	C2
Southern willow flycather	Empidonax traillii extimus	8	Cl
Arizona southwestern toad	Bufo microscaphus microscaphus	R	62
Narrow-headed garter snake	Thamnophis rufipunctatus	R	62
Mexican garter snake	Thamnophis eaues	R	C2
Chiricahua leopard frog	Rana chiricahuensis	A	C2
Loach minnow	Rhinicthys cobitis	F	T
Little Colorado spinedace	Lepidomeda vittata	F	I
Apache trout	Oncorhynchus apache	F	I
Zuni bluehead sucker	Catostomus discobolus varrowi	F	C2
Roundtail chub	Gila robusta	F	C2
False ameletus may fly	Ameletus falsus	I	C2
Arizona giant sand treader cricket	Daihinibaenetes arizonesis	I	C2
White Mountains water penny beetle	Psephenus montanus	I	C2
Three Forks springsnail	Fontelicella trivialis	I	C2
California floater	Anodonta californiensis	I	C2
Arizona cave amphipod	Stygobromus arizonensis	I	C2
Navajo Jerusalem cricket	Stenopelmatus navajo	I	C2
Navajo sedge	Carex specuicola	P	T
White Mountains clover	Trifolium lonqipes var. neurophyllum	P	C2
White Mountains paintbrush	Castilleja mogollonica	P	C2
Goodding onion	Allium gooddinoii	P	C1
Nutrioso milk vetch	Astragalus nutriosensis	P	C2

M = Mammals; B = Birds; R = Reptiles; A = Amphibians; F = Fish; l = Insects; and P = Plants

** E = Endangered; T = Threatened; C1 = Category 1; and C2 = Category 2

Gladiator milk vetch	Astragalus xiphoides	P	C2
Gila groundsel	Senecio auaerens	P	C2
no common name	Gentianella wislizeni	P	C2

Navaio 6ountv

Occult little brown bat	Myotis lucifugus occultus -	M	C2
Silky pocket mouse	Perognathus flavus goodnasteri	M	C2
Spotted bat	Euderma maculatum	M	C2
Navaho Mountain Mexican vole	Microtus mexicanus navaho	M	C2
Bald eagle	Haliaeetus leucocephalus	B	E
American peregrine falcon	Falco peregrinus anatum	B	E
Mexican spotted owl	Strix occidentalis lucida	B	P
Northern goshawk	Accipiter gentilis	B	C2
Apache goshawk	Accipiter gentilis anache	B	C2
Southern willow flycather	Empidonax traillii - extimus	B	Ct
Arizona southwestern toad	Bufo microscaphus microscaphus	R	C2
Narrow-headed garter snake	Thamnophis rufipunctatus	R	C2
Mexican garter snake	Thamnophis eaues	R	C2
Chiricahua leopard frog	Rana chiricahuensis	A	C2
Humpback chub	Gila cyipha	F	E
Loach minnow	Rhinicthys cobitis	F	T
tittle 6olorado spinedace	Lepidomeda vittata	F	T
Apache trout	Oncorhynchus apache	F	T
Roundtail chub	Gila robusta	F	C2
California floater	Anodonta californiensis	I	C2
Arizona cave amphipod	Stygobromus arizonensis	I	C2
Navajo Jerusalem cricket	Stenopelmatus navaio	I	C2
Peebles Navajo cactus	Peddiocactus peeblesianus var. peeblesianus	P	E
Navajo sedge	Carex specuicola	P	T
Gladiator milk vetch	Astragalus xiphoides	P	C2
Tusayan rabbitbrush	Chrysothamnus molestus	P	C2
Paper-spined cactus	Pediocactus papyracanthus	P	C2

State
New Ixico

San Juan County

Black-footed ferret	Mustela nigripes	M	E
Occult little brown bat	Myotis lucifugus occultus	M	C2
Spotted bat	Euderma maculatum	M	C2
American peregrine falcon	Falco peregrinus anatum	B	E
Arctic peregrine falcon	Falco peregrinus tundrius	B	T
Bald eagle	Haliaeetus leucocephalus	B	E
Mexican spotted owl	Strix occidentalis lucida	B	P

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Southern willow flycather	Empidonax traillii extimus	B	C1
Apache northern goshawk	Accipiter gentilis anache	B	C2
Northern goshawk	Accipiter gentilis	B	C2

Ferruginous hawk	Buteo regalis	B	C2
Loggerhead shrike	Lanius ludovicianus	8	C2
Mountain plover	Charadrius montanus	B	C2
White-faced ibis	Plegadis chihi	B	C2
Colorado squawfish	Ptychochelilus lucius	F	E
Razorback sucker	Xyrauchen texanus	F	E
Flannelmouth sucker	Catostomus latipinnis	F	C2
knowlton cactus	Pediocactus knowltonii	P	E
Mancos milkvetch	Astraaalus humillimus	P	T
Mesa Verde cactus	Sclerocactus mesae-verdae	P	T
Mancos saltplant	Proatriplex. pleiantha	P	C2
Beautiful gilia	Gilia formosa	P	C2
San Juan milkweed	Asclepias sanjuanensis	P	C2

D69

NEW MEXICO

San Juan County

Black-footed ferret, Mustela nigripes, endangered; in association with prairie dog towns in grass land plains and surrounding mountain basins up to 10,500 feet elevation. Surveys for black-footed ferrets are required if the prairie dog town is over 80 acres for black-tailed prairie dogs, band 200 hundred acres for white-tailed and Gunnison's prairie dogs. If the prairie dog town is greater than 1,000 acres, then the area should be evaluated for possible reintroduction of black-footed ferrets.

Occult little brown bat, Myotis lucifugus occultus, Category 2 candidate; montane dweller throughout New Mexico; colonies often near water; roosts in buildings. caves, bridges; probably hibernates in summer range area.

Spotted bat, Euderma maculatum, category 2 candidate; feeds near streams, and roosts in nearby cliffs, canyons or hillsides with loose rock; in summer found in ponderosa forest, migrating to lower elevations in fall and winter; hibernacula unknown; throughout western and north-central N.M.

Arctic peregrine falcon, Falco peregrinus tundrius, threatened; occasional migrant; does not nest or winter in New Mexico.

American peregrine falcon, Falco peregrinus anatum, endangered; summers in montane areas almost statewide; mainly in northern and Mogollon highlands. Nests in areas with steep cliffs and wooded/forested habitats, often near water. Prefers 6,500-8,500 feet elevations, but can be found from 3, 500-9,000 feet. Migrates and winters almost statewide.

Northern goshawk, Accipiter qentilis, Category 2 candidate; primarily mature coniferous forest; throughout montane areas of New Mexico.

Apache northern goshawk, Accipiter qentilis apache, Category 2 candidate; mature coniferous forest and pinyon-juniper woodland; A. g. apache may hybridize with the atricapillus subspecies throughout New Mexico.

Bald eagle, Haliaeetus leucocephalus endangered; Frequents Navajo Reservoir. over-winters in most counties from October through April; from the northern stateline, southward regularly to the Gila, lower Rio Grande, middle Pecos and Canadian valleys. Nests have been reported in San Juan, Colfax and Catron Counties. Presently, the only known nest is in the vicinity of Caballo Reservoir, Sierra County. Key winter habitat include areas such as Navajo Lake, Chama valley, Cochiti Lake, northeastern lakes (Raton to Las Vegas), lower Canadian valleys, Sumner Lake, Elephant Butte Lake, Caballo Reservoir, upper Gila Basin, Santa Rosa Lake, Tucumcari and Ute Lakes. Winter habitat in dry land areas include the region between Pecos Valley and the Sandias and Manzanos Mts, Capitan and Sacramento Mts, and the Mogollon Range.

Ferruginous hawk, Buteo reqalis, Category 2 candidate; Resident locally almost statewide; most regular in summer in the eastern plains and the San Agustin Plains. Key habitat are wide open grasslands and prairies at lower and middle elevations. Migrates and winters almost statewide. `
Mexican spotted owl, Strix occidentalis lucida, proposed threatened; shaded canyons, and montane forests of mature mixed conifer, ponderosa -pine and pine/oak.

Loggerhead shrike, Lanius ludovicianus, Category 2 candidate; grass/shrubland and open woodland; resident statewide; rare to fairly common locally at lower and middle elevations; casual at higher elevations.

Mountain plover, charadrius montanus, Category 2 candidate; short-grass prairie; also alkali flats, prairie dog towns, and over-grazed areas.

Summers in the east and southeastern plains, west to the San Agustin and North Plains, and across the south from the Tularosa basin to the Animas.

southw&stern willow flycatcher, Empidonax traillii extimus, Category 1 candidate; thickets, woodlands, pastures, and brushy areas, near riparian areas. Summers regularly in the San Juan, Chama. Rio Graride, San Francisco and Gila valleys, and in the San Juan Mountains.

White-faced ibis, Pleqadis chihi4 Category 2 candidate; marshes, shallow margins of muddy pools, ponds. and rivers; the river vallleys and tributaries of the San Juan1 Chama, Rio Grande, Pecos, and Canadian River.

Colorado squawf ish, Ptychocheilus lucius, endangered; large rivers with warm, swift turbid water; in N.M.1 suitable habitat exists in the San Juan River downstream of the confluence with the Animas River.

Flannelmouth sucker, Catostomus latipinnis, Category 2 candidate; larger rivers and streams; San Juan River and major tributaries.

Razorback sucker, Xyrauchen texanus, endangered; strong current of large rivers, and backwaters, eddies and pools, 1-3 m deep; also reservoirs and flooded gravel pits; in N.M., it has been reintroduced to the San Juan River.

Beautiful gilia, Gilia formosa, Category 2 candidate; gently rolling hills of the Animas Formation, in open arid Navaj oan Desert and in lower pinyon-juniper woodland-sagebrush, at 5700-6200 ft; known only from northeastern San Juan County.

Knowlton cactus, pediocactus knowltonii, endangered; gravelly, sagebrush-pinyon pine slopes at 6,000-6,500 ft; occurs in northeastern San Juan County, and along the Los Piflos River in northeastern Rio Arriba County. Mancos milkvetch, Astragalus humillimus, threatened; pinyon pine at 4, 000-5,000 ft; on slopes and sandstone ledges of the Hogback west of Waterflow.

Mancos saltplant, Proatriplex pleiantha, Category 2 candidate; saline and barren toeslopes of Mancos clay and shale hills, at 4900 ft; northwestern San Juan County.

Mesa Verde cactus, Sclerocactus mesae-verdae, threatened; associated with Atriplex spp. in dry clay soils along drainage ways; found in the Four Corners Platform area at 4,000-6,000 ft.

San Juan milkweed, Asclepias sanjuanensis, Category 2 candidate; sandy-loam soils, on slopes and floodplains, disturbed sites, erosion channels, trails and two-track roadways; in pinyonjuniper. at 3,000-5,600 ft; along the San Juan River, between and around Farmington and Bloomfield.

BALD EAGLE
(Haliaeetus leucocephalus)

STATUS: Endangered (32 FR 4001, March 11 1967; 43 FR 6233. February 14, 1978) without critical habitat.

SPECIES DESCRIPTION: This is a large eagle with white head and tail in the adults. immature individuals are dark with varying degrees of light mottiing. The feet are bare Of feathers.

HABITAT: bald eagles require large trees, snags or cliffs nar water for nesting, with abundant fish and waterfowl for prey. They spend the winters along major rivers, reservoirs, Or in arm where fish and/or carrion is available. Fish are the primary food source, but waterfowl, small mammals, and carrion are also important food items for breeding, wintering and transient eagles.

RANGE: Historic: Occurring throughout the U.S., Canada, and Northern Mexico this species is usually found near the seacoast, inland lakes, and rivers. The largest breeding populations are found in southern Alaska, along the west coast Of Canada and Washington, around the Great Lakes, and in Florida. Resident eagles and wintering populations occur in Arizona.

Current: Wintering eagles are found along rivers and major reservoirs in Arizona. Approximately 200 to 300 - eagles winter In Arizona. with many in the White Mountains and along the Mogollon Rim. A small resident population nests primarily along the Salt and Verde rivers In Arizona. New nest sites along the Gila, Bill Williams, and Agua Fria drainages indicate that the population may be increasing. However, this increase may reflect Increased search effort rather than population expansion.

ReaSONS FOR DECLINE/VULNERABILITY: Threats include degradation and loss. Of riparian habitat, pesticide-induced reproductive failure, ingestion of lead-poisoned waterfowl. shooting of individuals, timber harvest, loss of foraging perches, and human disturbance.

NOTES: A Recovery Plan was approved in 1982.

Listed as endangered by the State of Arizona.

Figure (Page D72 the picture of bald eagle)

Figure (Page D73 BALD eaGLE...)

AMERICAN PEREGRINE FALCON

(Falco peregrinus anatum)

STATUS: Endangered (35 FR 16074, October 13,1970; 35 FR 8495, June 2â 1970) without critical habitat.

SPECIES DESCRIPTION: A reclusive, crow-sized falcon which is slatey blue-gray above, whitish below with fine dark barring. The head is black with a masked or helmeted appearance. The wings are long and pointed. Loud wailing calls are given during Feeding.

HABITAT: This falcon inhabits areas with cliffs and steep terrain, preferably near water or woodlands where bird (its primary prey) concentrations are high. In Arizona, it prefers elevations above 5,000 feet, but it may be found from 3,500-9,000 feet.

RANGE: Historic: its breeding range stretched from Canada and Alaska south into Baja California, the central Mexican highlands, and northwest Mexico, including the continental United States. Northern birds probably winter in Mexico and Central and South America. In Arizona, birds were found over the entire state and included both resident and migrants.

Current: Most breeding populations are confined to the mountainous areas of the western United State and Canada. in Arizona, breeding pairs are now well distributed throughout suitable habitat statewide, except the low elevation deserts of the southwestern quarter of the state. Migrant and wintering birds include both the anatum and tundrius subspecies. Arizona breeding pairs appear to be year-round residents.

ReaSONS FOR DECLINE/VULNERABILITY: This falcon is endangered as a result of reproductive failure due to organochlorine pesticides.

NOTES: The Recovery Plan was revised in 1984. Pacific and Rocky Mountain Recovery Plans are currently being amended.

The Arctic Peregrine Falcon (Falco peregrinus tundrius) is listed as threatened (49 FR 10520; March 20, 1984). This subspecies is slightly smaller and paler than the American pegrine. It does not nest in Arizona, but may occasionally pass through On migration to and from wintering grounds in Central and South America.

Listed as a candidate species by the State of Arizona

Figure (Page D74 picture of American Peregrine Falcon)

Figure (Page D75 American Peregrine Falcon....)

LOACH MINNOW

STATUS: Threatened (51 FR 39468; October 28, 1986). Critical habitat proposed (50 FR 25380; June 18,1985); finalization under review.

SPECIES DESCRIPTION: The loach minnow ha smell (less than 3 Iches), slender, elongated fish, olive colored with dirty white spots at the base of the dorsal and caudal fins. Breeding males develop vivid red-orange markings.

HABITAT: This flsh ss a bottom dweller of small to large perennial Creek*s and rivers, typically found in shallow turbulent riffles with cobble subutate, swift currents and filamentous algae. Recurrent flooding is instrumental in maintenance of quality habitat.

RANGE: Historic: This species was once common throughout much of the Gila River system above Phoenix, including the Gila, Blue, Tularosa, White, verde, Salt, San Pedro, and San Francisco Rivers In Arizona and New Mexico.
Current: Aravalpa Greek, Graham and Pinal Counties, Arizona; upper Gila River, Grant and Catron Counties, New Mexico; Dry Blue Creek, Catron County, New Mexico; San Francisco and Tularosa Rivers, Catron County, New Mexico and Greenlee County, New Mexico; Blue River and Campbell Blue Creek, Greenlee County, Arizona, and White River, Navajo and Gila Counties, Arizona.

Potential: Undiscovered populations of loach minnow may exist in unsampled Gila basin streams, particularty on the White Mountain Apache and San Carlos Apache Indian Reservations.

ReaSONS FOR DECLINE/VULNERABILITY: This minnow is threatened by habitat destruction due to impoundment, channel downcutting, substrate sedimentation, water diversion, ground water pumping, and the spread of exotic predatory and competitive fishes.

LAND MANAGEMENT/ OWNERSHIP: In Arizona: United States Forest âService (Apache-Sitgreaves National Forests), White Mountain Apache Indian Reservation, Bureau of Land Management (Safford District), The Nature Conservancy, private. In New Mexico: United States Forest Service (Gila National Forest), Bureau of Land Management (Las Cruces District), The Nature Conservancy, State of New Mexico, Gila Cliff Dwellings National Monument, private.

NOTES: Proposed critical habltat is located in portions of Aravalpa Creek, Blue River, Campbell Blue Creek, San Francisco River, Dry Blue Creek, Tularosa River, East, West. and Middle Forks of the Gila River, and the main stem upper Gila River. For the exact location of proposed critical habitat, see 50 FR 25386.

A Recovery Plan was approved September 30, 1991.

Listed by the State of Arizona (threatened and New Mexico (endangered group 1).

Figure (Page D76 picture of Loach Minnow...)

Figure (Page D77 LOACH MINNOW ....)

LITTLE COLORADO SPINEDACE

STATUS: Threatened (52 FR 35054; September 16.1987) with Critical habitat

SPECIES DESCRIPTION: This is a small (less than 4 iches) silvery minnow which is darker on the back than the belly. It feeds on aquatic invertebrates.

HABITAT: Inhabits moderate to small streams and is characteristically found in pools with water flowing over fine gravel and slit-mud substrates. Many of the streams are seasonally intermittent at which times the Little Colorado spinedace persists in the deep pools and spring areas which retain water. During flooding the spinedace redistributes itself throughout the stream. Spawning primarily occurs in early summer, but some spawning continues until early fall.

RANGE: Historic: Endemic to the upper portions of the Little Colorado River and its north-flowing permanent tributaries on the Mogollon Rim and the northern slopes of the White mountains in eastern Arizona.

Current: Portions of the East Clear Creek and its tributaries, Coconino County; Chevelon Creek and Silver Greek, Navajo County; Little Colorado River and Nutrioso Creek. Apache County, Arizona.

ReaSONS FOR DECLINE/VULNERABILITY: Habitat distruction from impoundment, dewatering, riparn destruction, and other watersheded disturbances; use of fish toxlcants; and the introduction and spread of exotic predatory and competitive fish species.

LAND MANAGEMENT/OWNERSHIP: Apache-Sitgreaves National Forests, Arizona Game and Fish Department, Bureau of Land Management (Phoenix District), State of Arizina (trust lands), and private.

NOTES: Critical habitat includes eighteen miles of East Clear Creek, Coconino County; eight miles of Chevelon Creek, Navajo County; and five miles Of Nutrioso Creek, Apache County.

Listed as threatened by the State of Arizona

A Recovery Plan is in preparation.

Figure (Page D78 picture of Little Colorado Spinedace...)

Figure (Page D79 LITTLE COLORADO SPINEDACE...)

HUMPBACK CHUB
(Gila cypha)

STATUS: Endangered (32 FR 4001; March 11, 1967) without critical habitat.

SPECIES DESCRIPTION: This fish is a fairly large (less than 20 inches) minnow characterized by a narrow flattened head and long fleshy snout, large fins, and a very large hump between the head and the dorsal fin.

HABITAT: It occurs in a variety of riverine habitats, aspeciallâây canyon areas with fast current, deep pools, and boulder habitat.

RANGE: Historic: Ended to the Colorado River Basin from below Lake Mead (Arizona/Nevada) to Flaming Gorge on the Green River, Wyoming, and Yampa River, Colorado.
Currant: In Arizona this species occurs in the Little Colorado River, from its confluence with the Colorado River to eight miles upstream; and in the Colorado River in Grand and Marble Canyons (Coconino County). Populations are also found in Cataract and Westwater Canyons, Colorado River, and Desolations and Gray Canyons, Green River, Utah; Black Rooks, Colorado River, Colorado; Dinosaur National Monument," Green river, Colorado and Utah; and Dinosaur National Monument, Yampa River, Colorado.

ReaSONS FOR DECLINE/VULNERABILITY: Alteration of historic habitat caused by dam construction, water diversion and channelizatlon; competition with and predation by Introduced, non-native fishes; and hybridization with other Gila species;

LAND MANAGEMENT/OWERSHIP: in Arizona: National Park Service (Grand Canyon National Park), Navajo Indian Reservation.

NOTES: Recovery Plan approved August 22,1979. It was revised May 15, 1984, and September 19, 1990.

Listed as endangered by the State of Arizona

A small population of wild fish from the little Colorado River is being held at the Arizona Game and Fish Department Page Springs Hatcher (yavapal County).

Figure (Page D80 Picture of Humpback Chub...)

Figure (Page D81 Humpback Chub....)

APACHE TROUT
(Oncorhynchus apache)

STATUS: Threatened (40 FR 29864; July 19, 1975) without critical habitat. Originallyl isted as endangered in 1967.

SPECIES DESCRIPTION: This yellow or yellow-olive cutthroat-like trout has large dark spots on body. Its dorsal, anal, and caudal fins edged with white. It has no red lateral band.
HABITAT: Occurs In small, cold, high-gradient streams. These streams have substrates consisting & Hers, rocks and gravel with some sand or silt and flow through mixed conifer forests.

RANGE: Historic: Headwater streams of the Black, White, San Francisco, and Little Colorado Rivers inn the White Mountains of eastern Arizona;
Current: Approximately thirty sites are presently known to support native or reintroduced populations of Apache trout on the Fort Apache Indian Reservation and the Apache-Sitgreaves National Forests. Genetic pority of some of those populations is in question and is under investigation. Populations introduced outsite of historic range exist on the Coronado and the northern portion of the Kaibab National Forests.

ReaSONS FOR DECLINE/VULNERABILITY: Hybridization with introduced rainbow and cutthroat trouts, predation and competition by introduced fishes, and habitat degradation.

LAND MANAGEMENT/OWNERSHIP: United States Forest service and Fort Apache Indian Reservation.

NOTES: Recovery Plan revised in 1983.
Special regulations allow Arizona to manage this species as a sport fish.

Two hundred and fifty thousand or more are produced annually for reintroduction.

Breeding stock maintained at Williams Creek National Fish Hatchery.

Figure (Page D82 picture of Apache Trout...)

Figure (Page D83 APACHE TROUT...)

PEEBLES NAVAJO CACTUS
(Pediocactus peeblesianus var. peeblesianus)

STATUS: Endangered (44 FR 61922: Octo~r 2G. 1979) without critical habitat.

SPECIES DESCRIPTION: This caCtus is very difficult to find because the plants are very small and during dry weather plants retract into the soil. Stems are solitary or rarely clustered, globose, and up to 1 inch tall and about 0.74 inch in diameter. The 4 (3-5) radial spines are arranged in a twisted cross - central spines are absent Flowers are yellow to yellow-green, are up to 1 inch in diameter. and appear in the spring.

HABITAT: Occurs on gravelly soils of the Shinarump conglomerate of the Chinie Formation at elevations ranging from 5,400-5,6OO feet Associated species are sparsely scattered, low shrubs and grasses of the Navajoan Desert.

RANGE: Current: Central Navajo County, near Holbrook, Arizona.
Potential: Sites in the general geographic area that meet the habitat requirements.

ReaSONS FOR DECLINE/VULNERABILITY: The specific habitat requirements, limited geographic range, and small number of individuals make this species vulnerable to extinction. Threats to the species include gravel mining, off-road vehicle traffic, urban development, road construction, pesticide application. Reproduction may be insufficient to maintain populations over the long term.

LAND MANAGEMENT/OWNERSHIP: Bureau of Land Management and private.

NOTES: Recovery Plan approved 1984. Peebles Navajo Cactus Habitat Management Plan approved by Bureau of Land Management 1985. Demographic studies have been occurring since 1980.

Protected from Illegal international trade by the Convention on International Trade in Endangered Species of Wild Fauna and Flora (CITES). Also proteCted by the Arizona Native Plant Law.

Pediocacti are some of the most difficult cacti to grow in cultivation.

Figure (Page D84 Picture of Peebles Navajo Cactus...)

Figure (Page D85 Peebles Navajo Cactus...)

NAVAJO SEDGE

STATUS: Threatened (50 FR 19370; May 8. 1985) with critical habitat..

SPECIES DESCRIPTION: A member of the sedge family (Cyperaceae). this grass-like plant reaches a height of 10-16 inches. Numerous stems grow from a rhizome (underground stem), giving each Plant a clumped form. Each plant has both male and female flowers, the male flowers occurring only on the ends of stems and the female flowers occurring below the male flowers or in spikes on the sides of stems.

HABITAT: Seep-springs on vertical cliffs of pink-red Navajo sandstone at 5,700-6000 feet elevation. These drainages are spectacular examples of the deep, sheer-walled canyons of the Colorado Plateau geographic region. The plant community inhabiting the vertical seeps includes Mimulus eastwoodlae (monkey flower) and Epipactis gigantea (weed orchid).

RANGE: Currant: Formerly known from only a few localities in the Navajo Creek drainage (Coconino County), recent surveys have documented Navajo sedge in other drainage systems in Apache and Navajo Counties. Navajos living In the Navajo Creek area recall the presence of the Navajo sedge in areas where it is not found today.

Recetilly, a po~ation was found in San Juan Counry Utah. Potential: Surveys for this species are incomplete. Navajo sedge might be located in the general regional area of Arizona and Utah, in seep-springs on canyon walls & Navajo sandstone or other similar eolian sandstone formations.

ReaSONS FOR DECLINE/VULNERABILITY: The specialized and limited available habltat make this species vulnerable to man-caused threats. Threats to the species include livestock grazing and trampling (at accessible sites) and the potential for habltat loss due to underground water pumping.

LAND MANAGEMENT/OWNERSHIP: Navajo Nation.

NOTES: Recovery Plan approved 1987. Critical habitat is on the Navajo Nation in Coconino County and contains three groups of springs near iscription House Ruins (see 50 FR 19370 for details).

protected by the Arizona Native Plant law and the Navajo Nation.

Figure (Page D86 picture of Navajo Sedge...)

Figure (page D87 NAVAJO SEDGE...)

MEXICAN GRAY WOLF

STATUS: Endangered (32 FR 4001, March 11,1967; 43 FR 1912, March 9,1978) without critical habitat.

SPECIES DESCRIPTION: This is a a large, dog-like carnivore with its color varying, but usually as some shade of gray. It has a distinct white lip line around its mouth Adults weigh between 60-9o pounds.

HIABITAT: This subspecies inhabits chaparral, woodland and forested areas above approximately 4,000 12,000 feet elevation. This wolf will Cross desert areas but will not remain there.

RANGE: Historic: This wolf occurred in southeastern Arizona, southwest New Mexico and
Trans-Pecos region of Texas south through the Sierra Madre of Mexico. Current: It
may persist in isolated pockets in the Sierra Modre. It was axtirpated from the United
States, although occasional undocumented sightings are reported from Arizona=New
Mexico border
Potential: Unknown. Areas in Arizona and New Mexico are under preliminary
evaluation for captive release sites.

ReaSONS FOR DECLINE/VULNERABILITY: Federal, State, and private predator control
programs eliminated wolves from Arizona, Texas, and New Mexico by the 1920's
The same programs may have eliminated the wolf in Mexico in the 1980's.

NOTES: A Recovery Plan was approved September 15,1982. A captive breeding program is
underway in several United States and Mexican zoos.

Listed as endangered by the State of Arizona.

Figure (Page D88 picture of Mexican Gray Wolf

Figure (Page D89 MEXICAN GRAY WOLF...)

United States Department of the Interior
FISH AND WILDLIFE SERVICE
Mountain-Prairie Region

IN REPLY REFER TO:	MAILING ADDRESS:	STREET LOCATION:
	Post Office Box 25486	134 Union Blvd.
FWE	Denver Federal Center	Lakewood, Colorado 80228
MAIL STOP 60120	Denver Colorado 80225	

DEC 22 1992

Maureen R. Flynn, Project Manager
Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

Dear Ms. Flynn:

This responds to your letter of October 2, 1992, received by this office on

October 26, 1992, regarding the Bonneville Power Administration (Administration) Non-Federal Participation Environmental Impact Statement.

In accordance with Section 7(c) of the Endangered Species Act of 1973, as amended, we determined that the following threatened and endangered species may be present in the project areas for the States of Montana, Wyoming, and Utah.

Candidate species that-may occur within the project area also are identified below. Many Federal Agencies have policies to protect candidate species from further population declines. Our office would appreciate receiving any information available on the status of these species in or near the project area. Consideration of these species is important in preventing their inclusion on the Endangered Species list.

Common Name	Scientific Name	Stat	Cat
Montatia			
Bald eagle	Haliaeetus lecucocenhalus	E	
Peregrine falcon	Falco Deregrinus	E	
Grizzly bear	Ursus arctos horribilis	T	
Gray wolf	Canis lupus	E	
Utah			
Spotted frog	Rana uretiosa	C	2
Northern goshawk	Accipiter gentilis	C	2
Ferruginous hawk	Buteo reaalis	C	2
Black tern	Chlidonias niger	C	2
Peregrine falcon	Falco peregrinus	E	
Bald eagle	Haliaeetus leucocephalus	E	
Western least bittern	Ixobrychus exilis hesperis	C	2
Loggerhead shrike	Lanius ludovicianus	C	2

Utah (continued)

White-Faced ibis	Plegadis chihi	C	2
western snowy plover (interior population)	Charadrius alexandrinus nivosus	C	2
Mexican spotted owl	Strix occidental is lucida	P	
Flannelmouth sucker	Catostomus latipinnis	C	2
Humpback chub	Gila cypha	E	
Bonytail chub	Gila eleaans	E	
Roundtail chub	Gila robusta	C	2
Colorado squawfish	Ptychocheilus lucius	E	
Razorback sucker	Xyrauchen texanus	E	
Bonneville cutthroat trout	Oncorhvnchus (=salmo) clarki utah	C	2
North American lynx	Felis lynx canadensis	C	2
North American wolverine	Gulo gulo luscus	C	2
Black-footed ferret	Mustela nigripes	E	
Deseret milk-vetch	Astragalus desereticus	C	2
Creutzfeldt catseye	Cryotantha cretuzfeldtii	C	2
Canyon sweetvetch	Hedvsarum occidentale var. canone	C	2

Low hymenoxys	Hvmenoxvs deoressa	C	2
No common name	Penstemon leotanthus	C	2
Tidestrom beardtongue	Penstemon tidestromii	C `	2
isard beardtongue	Penstemon ward ii	C	2
Clay phacelia	Phacelia araillacea	E	
Maguire daisy	Erigeron maquirei var. maquirei	E	
isinkler cactus	Pediocactus winkleri	C	1
Jones psorothamnus	Psorothamnus nolvadenius var. jonesii	C	2
Shrubby reed-mustard (Toad flax cress)	Schoencrambe (=glaucocarpum) suffrutescens	E	
Uinta Basin hookless cactus	Sclerocactus alaucus	T	
Thompson's pink flame-flower	Talinum thompsonii	C	2

Wyomig

Black-footed ferret	Mustela nigripes	E
Bald eagle	Haliaeetus leucocephalus	E
Peregrine falcon	Falco neregrinus	E
Whooping crane	Grus americana	E
Gray wolf	Canis lupus	E
Grizzly bear	Ursus arctos horribilis	T

Prairie dog(Cynomvs sp.) towns are considered potential habitat for black-footed ferrets. Thus, if white-tailed prairie dog (C. leucurus) colonies or complexes greater than 79 acres will be disturbed, surveys for ferrets should-
be conducted. This is true even if the portion of the colonies that will actually be disturbed Is less than 79 acres.

Wyominq [continued)

If the proposed action will lead to withdrawals from the Green River and, thus, water depletion (consumption) in the Colorado River System, your evaluation should include the following species:

Colorado squawfish	Ptychocheilus lucius	E
Humpback chub	Gila cypha	E
Bonytail chub	Gila elegans	E
Razorback sucker	Xyrauchen texanus	E

Mammals

Preble's shrew	Sorex areblei	C	2
Allen's 13-lined ground squirrel	Snermonhilus tridecemlineatus alleni	C	2
North Amer. wolverine	Gulo gulo luscus	C	2

North Amer. lynx	Felis lynx canadensis	C	2
Birds			
Trumpeter swan	Cygnus buccinator	C	2
White-faced ibis	Plegadis chihi	C	2
Harlequin duck	Histrionicus histrionicus	C	2
Ferruginous hawk	Buteo reaalis	C	2
Northern goshawk	Accipiter gentilis	C	2
Mountain plover	Charadrius montanus	C	1
Long-billed curlew	Numenius americanus	C	3
Black tern	Chlidonias niqer	C	2
Loggerhead shrike	Laniusludovicianus	C	2
Amphibians			
Western boreal toad	Bufo boreas boreas	C	2
Spotted frog	Rana pretiosa	E	2
Fish			
Bonneville cutthroat trout	Salmo clarki utah	C	2
Flannel mouth sucker	Catostomus latininnis	C	2
Roundtail chub	Gila robusta	C	2
Invertebrates			
Jackson Lake springsnail (=Elk Island snail)	Pyrgulopsis (Fonelicella) robusta	C	2
Jackson Lake snail	Helisoma (Carinifex)	C	2
Plants			
Ross' bentgrass	Agrostis rossiae	C	2
Payson's milk-vetch	Astragalus paysonii	C	2
Keeled bladderpod	Lesouerella carinata	C	2
Payson's bladderpod	Lesouerella pavsonii	C	2
Dorn's twinpod	Physaria dornii	C	2

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*1 = Federal threatened and endangered listing appears appropriate and is anticipated.
2 = Current data insufficient to support listing.
3c= More widespread or abundant than previously believed, or no immediate threats identified.

Maureen R. Flynn, Project Manager

Currently, no plant species in Wyoming are listed as threatened or endangered; however, Federal Agencies are encouraged to consider candidate plants in any project review. The Wyoming Natural Diversity Database maintains the most current information on sensitive plants in Wyoming.

Section 7(c) of the Endangered Species Act requires that Federal Agencies proposing major construction actions complete a biological assessment to determine the effects of the proposed actions on listed and proposed species. If a biological assessment is not required (i.e., all other actions), the Administration is responsible for review of proposed activities to determine whether listed species will be affected. We would appreciate the opportunity to review the determination document.

For those actions where a biological assessment is necessary, it should be completed within 180 days of initiation but can be extended by mutual agreement between the Administration and the U.S. Fish and Wildlife Service (Service). If the assessment is not initiated within 90 days, the list of threatened and endangered species should be verified with the Service prior to initiation of the assessment. The biological assessment may be undertaken as part of the Administration's compliance of Section 102 of the National Environmental Policy Act (NEPA) and incorporated into the NEPA documents. We recommend that biological assessments include:

1. a description of the project;
2. a description of the specific area potentially affected by the action;
3. the current status, habitat use, and behavior of threatened and endangered species in the project area;
4. discussion of the methods used to determine the Information In item 3;
5. direct and indirect impacts of the project to threatened and endangered species;
6. an analysis of the effects of the action on listed and proposed species and their habitats including cumulative impacts from Federal, State, or private projects in the area;
7. coordination measures that will reduce/eliminate adverse impacts to threatened and endangered species;
8. the expected status of threatened and endangered species in the future (short and long term) during and after project completion; -
9. determination of "is likely to adversely affect" or "is not likely to adversely affect" for listed species;
10. determination of "is likely to jeopardize" or "is not likely to

jeopardize" for proposed species; and

11. citation of literature and personal contacts used in assessment.

If it is determined that any agency program or project "is likely to adversely
affect" any listed species, formal consultation should be initiated with the Service. If it is concluded that the project "is not likely to adversely affect" listed species, the Service should be asked to review the assessment and concur with the determination of "no adverse effect."

A Federal Agency may designate a non-Federal representative to conduct informal consultation or prepare biological assessments. However, the ultimate responsibility for Section 7 compliance remains with the Federal Agency, and written notice should be provided to the Service upon such a designation. We recommend that federal Agencies provide their non-Federal representatives with proper guidance and oversight during preparation of biological assessments and evaluation of potential impacts to listed species. Section 7(d) of the Endangered Species Act requires that the Federal Agency and permit or license applicant shall not make any irreversible or irretrievable commitment of resources which would preclude the formulation of reasonable and prudent alternatives `until consultation on listed species is completed.

The following discussion outlines other issues that should receive full treatment in the analysis of these projects.

Raptor-Proofing Additions or Improvments to Facilities: Two primary causes of raptor deaths in Wyoming are electrocutions and collisions with power lines. If any part of this project will involve construction of new power lines or modification Of existing lines, the Service urges the Administration to take strong precautionary measures to protect raptors through proper raptor-proofing techniques. Federal Register 49, Section 1729.10, 1984, allows for deviations from Rural Electric Association construction standards for raptor protection. Structures which are designed for raptor protection shall be in accordance with Suggested Practices For Raptor Protection on Power
Lines. The State of the Art, Raptor Research Report No. 4, 1981, published by the Raptor Research Foundation, Inc. (also cited in Federal Register 11620, 1984), provided that such structures meet with the National Electrical Safety Code. Authority for these measures resides with Section 9 of the Endangered Species Act of 1973 (as amended), the Migratory Bird Treaty Act, and the Bald Eagle Protection Act which protect bald and golden eagles. In the above cited Federal Register publication, the following bulletins are also recommended: Rural Electric Association Bulletin 40-7, National Electrical Safety Code ANSI C2, 1981 Edition, and Rural Electric Association Bulletin 61-60, Power Line Contacts by Eagles and Other Large Birds.

Herbicide Use and Revegetation Needs: The Service is concerned with the use of herbicides around new and existing facilities. Whenever possible, manual control (hand pulling) and biological control should be the primary method of vegetation control. If chemical control becomes necessary, all impacts of that control should be analyzed.

Noxious weed invasions may occur in areas of disturbance. Introduced species may outcompete sensitive plant species and alter species composition within the community. Care should be used in the choice of plantings and seeding mixes, and only native vegetation and seed mixes should be used.

Water Quality/Habitat Quality: The Service is concerned with water quality impacts of the proposed project, particularly with respect to their effects on
fisheries, migratory birds, and federally listed-threatened and endangered species. The analysis should describe project activities that may affect water quality or that have the potential to expose fish and wildlife to

hazardous substances. Such activities may include, but are not limited to: wastewater discharges, transportation of hazardous materials, spills, and evaporation ponds. Because selenium is a commonly detected trace element in Wyoming and has been detected in varying concentrations in ground and surface waters and soils, the analysis should assess, if appropriate, the project's potential to mobilize selenium and cause bioaccumulation in the food chain.

Wastewater evaporation ponds can cause bird mortalities. Some powerplants use trona wastewater to neutralize the acidity of scrubber desulfurization water. Trona wastewater contains high concentrations of sodium decahydrate which will
crystalize on any solid objects on the pond surface at temperatures as high as
70 oF. Birds landing on the evaporation ponds will experience crystallization of this compound on their feathers. The crystallization destroys the insulative qualities of the feathers causing birds to die of exposure. Sodium decahydrate crystals also can result in a loss of buoyancy and cause birds to drown. Birds also can ingest the sodium decahydrate crystals during preening and die of sodium toxicity.

The high alkalinity of trona evaporation ponds allows them to remain ice free longer than nearby freshwater ponds, rivers, and lakes. During the cold season when all other waterbodies are frozen, aquatic birds migrating through the area will seek the open water at the trona evaporation ponds. The risk to birds is greatest during this time as crystallization and hypothermia are enhanced by the colder temperatures.

The Migratory Bird Treaty Act (16 U.S.C. 703-711) prohibits the "taking" of migratory birds. Taking can include the following activities resulting in migratory bird mortalities: exposed waste pits, hazardous materials spills, and oil spills. The maximum criminal penalty for corporations unlawfully taking a protected migratory bird is a $10,000 fine, or 6 months in jail, or both for each count. There is no "allowable take" under the Migratory Bird Treaty Act; the taking of just one bird is a violation.

Fish and Wildlife: Short-term and long-term impacts of the proposed project on fish and wildlife and their habitats should be given full-treatment in the analysis. As indicated above, in addition to assessing impacts to threatened, endangered, and candidate species, the analysis should address-impacts to raptors and other migratory birds.

This species list and these preliminary comments are offered pursuant to NEPA,
the Endangered Species Act, and the Fish and Wildlife Coordination Act. Please keep the Service Informed of any developments or decisions concerning this project.

Wetland Impacts: We are concerned that wetlands may be impacted by the proposed project. In meeting its responsibilities for wetland protection and conservation, the Administration must ensure that proposed activities do not result in the taking of any Federal trust wildlife resources nor lead to the contamination of other water sources. Thus, we recommend measures be taken to avoid or mitigate any wetland losses in accordance with Section 404 of the Clean Water Act, the Fish and Wildlife Coordination Act, Executive Order 11990
(wetland protection), and Executive Order 11988 (floodplain management), as

well as President Bush's goal of "no net loss of wetlands." If wetlands may be impacted by the proposed action, those (wetlands) in the project area should be inventoried and fully described in terms of functions and values. Acreage of wetlands, by type, should be disclosed and specific actions outlined to avoid, minimize, and compensate for unavoidable wetland impacts.

The Service recommends that the Administration request assistance from the U.S. Army Corps of Engineers (Corps) to determine whether a Section 404 Clean Water Act permit will be required for the proposed work. Under Section 404(b) (1) guidelines of the Clean Water Act, the analysis should describe alternative actions which avoid, minimize, and compensate for unavoidable wetland impacts. The Service will participate in review of any application for a Section 404 permit. We advise early consultation with the Service and other appropriate agencies on wetland matters. If wetlands are involved but the Corps determines that an individual permii is not required, the Administration should ensure that the Intent of Section 404 of the Clean Water Act is met. Wetland issues should be disclosed and addressed in the analysis even if a Section 404 permit is not required.

Wetlands mitigation should include the following strategy in order of preference pursuant to Section 404(b) (1) guidelines and the memorandum of agreement between the Corps and Environmental Protection Agency:
(1) avoidance; (2) impact minimization; (3) mitigation in-kind, on-site;
(4) mitigation in-kind, off-site; (5) mitigation out-of-kind, on-site; and
(6) mitigation out-of-kind, off-site. In addition, the following rides of mitigation, listed in order of preference, may be implemented for wetlands mitigation if avoidance and impact minimization are not feasible:
(1) wetlands restoration, (2) wetlands creation, and (3) wetlands enhancement.
As indicated, only after it is demonstrated that total avoidance and impact

ainimization are not feasible should other mitigation strategies be considered. The general objective and goal of mitigation should include replacement of functional values and cumulative area lost due to project implementation.

Sincerely,

Assistant Regional Director
Fish and Wildlife Enhancement

D96

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Ecological Services

3704 Griffin Lane SE, Suite 102
Olympia, Washington 98501-2192
(206) 753-9440 FAX: (206) 753-9008

March 10, 1993

Maureen Flynn
NFP-eis Project Manager
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

FWS Reference: 1-3-93-SP-340-346
Dear Ms. Flynn:

This is in response to your letter dated November 4, 1992, and received in this office on December 4, Enclosed is a list of listed threatened and endangered species,- and candidate species (Attachment A), that may be present
within the area of the proposed Bonneville Power Administration (BPA) Service Area Non-federal Participation project in Washington (see enclosed list) in multiple counties in Washington. The list fulfills- the requirements of the Fish and Wildlife Service (Service) under Section 7(c) of the Endangered Species Act of 1973, as amended (Act). We have also enclosed a copy of the requirements for BPA compliance under the Act (Attachment B).

Should the biological assessment determine that a listed species is likely to be affected (adversely or beneficially) by the project, the BPA should request
Section 7 consultation through this office. If the biological assessment determines that the proposed action is "not likely to adversely affect" a

listed species, the BPA should request Service concurrence with that determination through the informal consultation process. Even if the biological assessment shows a "no effect" situation, we would appreciate receiving a copy for our information.

Candidate species are included simply as advance notice to federal agencies of
species which may be proposed and listed in the future. However, protection provided to candidate species now may-preclude possible listing in the future.
If early evaluation of your project indicates that it is likely to adversely impact a candidate species, the BPA may wish to request technical assistance from-this office.

In addition, please be advised that federal and state regulations may require permits in areas where wetlands are identified. You should contact the

Seattle District of the U.S. Army Corps of Engineers for federal permit requirements and the Washington State Department of Ecology for state permit requirements.

Your interest in endangered species is appreciated. If yoti have additional questions regarding your responsibilities under the Act, please contact Jim Michaels or Kimberly Flotlin of my staff at the letterhead phone/addre-ss.

Sincerely,

David C. Frederick
Field Supervisor

kf/kr
Enclosures
SE/BPA/1-3-93-SP-340-346/Multi
c: WDW, Olympia (Nongame)
WNHP, Olympia

Project Name	County(ies) in which project occurs
Chandler	Benton
Chief Joseph	Douglas and Okanogan
Grand Coulee PG	Douglas and Okanogan
Ice Harbor	Franklin and Walia Walia
Little Goose	Columbia and Whitman

Lower Granite	Carfield and Whitman
Lower Nonumental	Franklin and Walla Walla
Roza	Kittitas
WPPSS No. l, 2, & 3	Senton
Centralia No. 1 & 2	Lewis

D99

ENDANGERED, THReaTENED, PROPOSED AND CANDIDATE SPECIES, AND CRITICAL HABITAT WHICH MY OCCUR IN THE VICINITY OF CHANDLER POWER AND PUMPING PLANT AND WPPSS No. 1, 2, & 3 NUCLeaR PLANTS IN BENTON COUNTY, WASHINGTON, AS LISTED BY THE U.S. FISH AND WILDLIFE SERVICE

1-3-93-SP-340

LISTED

Bald eagle (Haliaeeos]eucocephalus) - wintering bald eagles may occurs in the
county from about October 31 through March 31.

There are seven bald eagle communal winter night roosts located in the county at: T13N R26E S6; T13N R27E S23; T14N R26E S11; T14N R26E S14; T14N R27E S18; and T14N R27E S29 (two roosts in this section).

There are two bald eagle wintering concentrations located in the county at Lake Umatilla and near Hanford.

Peregrine falcon (Falco peregrinus) - spring and fall migrant falcons may occur in the county.

Major concerns that should be addressed in your biological assessment of project impacts to bald eagles and peregrine falcons are:

1. Level of use of the project area by eagles and falcons.

2. Effect of the project on eagles' and falcons' primary food stocks, prey species, and foraging areas in all areas influenced by the project.
3. Impacts from project implementation and/or activities (e.g., increased noise levels, increased human activity and/or access, loss or degradation of habitat) which may result in disturbance to eagles and falcons and/or their avoidance of the project area.

PROPOSED

None.

CANDIDATE

The following candidate species may occur in the county:

Black tern (Chlidonias niger)
Bull trout (Salvelinus confluentus)
California floater (mussel) (Anodonta californiensis (Lea, 1852))

Columbia pebblesnail (Fluminicola (=Lithoglyphus) columbianus (Hemphill in Pilsbry, 1899)) [great Columbia River spire snail]
Ferruginous hawk (Buteo regalis)
Loggerhead shrike (Lartius ludovicianus)
Lynn's clubtail (dragonfly) (Gomphus lynnae)
western sage grouse (Centrocercus urophasianus phaios)
Astragalus columbianus (Columbia milk-vetch)
Haplopappus liatriformis (Palouse goldenweed)
lomatium tuberosum (Hoover's desert-parsley)
Rorippa columbiae (Columbia yellow-cress)

D100

ENDANGERED, THReaTENED, PROPOSED AND CANDIDATE SPECIES, AND CRITICAL HABITAT WHICH MY OCCUR IN THE VICINITY OF THE CHIEF JOSEPH AND GRAND COULEE PC DAIS IN DOUGLAS AND OKANOGAN COUNTIES, WASHINGTON, AS LISTED BY THE U.S. FISH AND WILDLIFE SERVICE
1-3-93-SP-341

LISTED
Bald eagle (Haliaeeos leucocephalus) - wintering bald eagles may occur in the counties from about October 31 through March 31.
There are five bald eagle communal winter night roosts located in Douglas County at: T29N R27E S2; T30N R25E S29; T30N R25E S30; T30N R30E S6; AND T31N R29E S36.

There are four bald eagle communal winter night roosts located in the Okanogan County at T29N R23E S36; T29N R31E S16; T32N R2SE S8; and T32N R2SE S19.

There are three bald eagle wintering concentrations located in Douglas County at Lake Entiat, Bridgeport Bar, and Nespelem Bar along the Columbia River.

There are two bald eagle wintering concentrations located in the Okanogan County at Rufus Woods Lake and along the Okanogan River.

There are three bald eagle nesting territories located in Douglas County at T30N R25E S30; T30N R27E S30; and T30N R30E S4. Nesting activities occur from about January 1 through August 15.

There is a bald eagle nesting territory located in the âOkanogan County at T39N R25E S2. Nesting activities occur from about January 1 through August 15.

Gray wolf (Canis lupus) - may occur in the counties.

Peregrine falcon (Falco peregrinus) - spring and fall migrant falcons may occur in the counties.
Major concerns that should be addressed in your biological assessment of project impacts to listed species are:

1. Level of use of the project area by listed species.
2. Effect of the project on listed species' primary food stocks, prey species, and foraging areas in all areas influenced by the project.
3. Impacts from project implementation and/or activities (e.g., increased

noise levels, increased human activity and/or access, loss or degradation of habitat) which may result in disturbance to listed species and/or their avoidance of the project area.

PROPOSED

None.

CANDIDATE

The following candidate species may occur in the counties:

Black tern (Chlidonias niger)
Bull trout (Salvelinus confluentus)
California bighorn sheep (Ovis canadensis californiana)
California floater (mussel) (Anodonta californiensis (Lea, 1852))
Cascades frog (Ratta cascadae)
Columbia pebblesnail (fluminicola (=Lithoglyphus) columbianus (Hemphill in Pilsbry, 1899)) (great Columbia River spire snail]
Columbian sharp-tailed grouse (Tympanuchus phasianellus columbianus)
Ferruginous hawk (Buteo regalis)
Harlequin duck (Histrionicus histrionicus)
Loggerhead shrike (Lanius ludovicianus)
North American lynx (Felis lynx canadensis)
Pygmy rabbit (Brachylagus idahoensis)
Spotted frog (Rana pretiosa)
Western sage grouse (Centrocercus urophasianus phaios)
Allium constrictum (Douglas' constricted onion)
âDelphinium viridescens (Wenatchee larkspur)
Petrophytum cinerascens (Chelan rockmat)
Phacelia lenta (sticky phacelia)
Trifoliim thompsonii (Thompson's clover)

ENDANGERED, THReaTENED, PROPOSED AND CANDIDATE SPECIES, AND CRITICAL HABITAT WHICH MY OCCUR IN THE VICINITY OF THE ICE HARBOR AND LOWER MONMENTAL DAMS IN FRANKLIN AND WALLA WALLA COUNTIES, WASHINGTON, AS LISTED BY THE U.S. FISH AND WILDLIFE SERVICE
1-3-93-SP-342

LISTED

Bald eagle (Haliaeetus leucocephalus) - wintering bald eagles may occur in the counties from about October 31 through March 31.

There is a bald eagle wintering concentration located in Franklin County at Savage Island in the Columbia River.

Peregrine falcon [Falco peregrinus) - spring and fall migrant falcons may occur in the counties.

Major concerns that should be addressed in your biological assessment of project impacts to bald eagles and peregrine falcons are:

1. Level of useâof the project area by eagles and falcons.

2. Effect of the project on eagles' and falcons' primary food stocks, prey species, and foraging areas in all areas influenced by the project.

3. Impacts from project implementation and/or activities (e.g., increased noise levels; increased human activity and/or access, loss or degradation of habitat) which may result in disturbance to eagles and falcons and/or their avoidance of the project area.

PROPOSED

None.

CANDIDATE

The following candidate species may occur in the counties:

Black tern (Chlidonias niger)
Bull trout (Salvelinus confluentus)
California floater (mussel) (Anodonta californiensis (Lea, 1852))
Columbia pebblesnail (Fluminicola (=Lithoglyphus) columbianus (Hemphill in Pilsbry, 1899)) [great Columbia River spire snail]
Ferruginous hawk (Buteo regal is)
Harlequin duck (Histrionicus histrionicus)
Loggerhead shrike (Lanius ludovicianus)
Preble's shrew (Sorex preblei)
Spotted frog (Rana pretiosa)
Lupinus cusickii (Cusick's lupine)

D103

ENDANGERED, THReaTENED, PROPOSED AND CANDIDATE SPECIES, AND CRITICAL HABITAT WHICH MY OCCUR IN THE VICINITY OF THE LITTLE GOOSE DO IN COLUMBIA AND WHITMAN COUNTIES, WASHINGTON, AS LISTED BY THE U.S. FISH AND WILDLIFE SERVICE

1-3-93-SP-343

LISTED

Bald eagle (Haliaeetus leucocephalus) - wintering bald eagles may occur in the
counties from about October 31 through March 31.

Peregrine falcon (Falco peregrinus) - spring and fall migrant falcons may occur in the counties.

Major concerns that should be addressed in your biological assessment of project - impacts to bald eagles and peregrine falcons are:

1. Level of use of the project area by eagles and falcons.

2. Effect of the project on eagles' and falcons' primary food stocks, prey species, and foraging areas in all areas influenced by the project.

3. Impacts from project implementation and/or activities (e.g., increased noise levels, increased human activity and/or access, loss or degradation of habitat) which may result in disturbance to eagles and falcons and/or their avoidance of the project area.

PROPOSED

None.

CANDIDATE

The following candidate species may occur in the counties:

Black tern (Chlidonias niger)
Bull trout (Salvelinus confluentus)
California bighorn sheep (Ovis canadensis californiana)
California floater (mussel) (Anodonta californiensis (Lea, 1852))
Columbia pebblesnail (Fluminicola (=Lithoglyphus) columbianus (Hemphill in Pilsbry, 1899)) [great Columbia River spire snail]
Ferruginous hawk (Buteo regalis)
Harlequin duck (Histrionicus histrionicus)
Loggerhead shrike (Lanius ludovicianus)
Preble's shrew (Sorex preblei)
Spotted frog (Rana pretiosa)
Allium dictuon (Blue Mountain onion)
Aster jessicae (Jessica's aster)
Calochortus nitidus (broad-fruit mariposa)
Haplopappus liatriformis (Palouse goldenweed)
Lupinus cusickii (Cusick's lupine)
Polemonium pectinatum (Washington polemonium)
Rubus nigerrimus (northwest raspberry)
Silene spaldingii (Spalding's silene)

ENDANGERED, THReaTENED, PROPOSED AND CANDIDATE SPECIES, AND CRITICAL HABITAT WHICH MY OCCUR IN THE VICINITY OF THE LOWER GRANITE DAM IN GARFIELD AND WHITMAN COUNTIES, WASHINGTON, AS LISTED-BY THE U.S. FISH AND WILDLIFE SERVICE
1-3-93-SP-344

LISTED

Bald eagle (Haliaeetus leucocephalus) - wintering bald eagles may occur in the
counties from about October 31 through March 31.

Peregrine falcon (Falco peregrinus) - spring and fall migrant falcons may occur in the counties.

Major concerns that should be addressed in your biological assessment of project impacts to bald eagles and peregrine falcons are:

1. Level of use of the project area by eagles and falcons.

2. Effect of the project on eagles' and falcons' primary food stocks, prey species, and foraging areas in all areas influenced by the project.
3. Impacts from project implementation and/or activities (e.g., increased noise levels, increased human activity and/or access, loss or degradation of habitat) which may result in disturbance to eagles and falcons and/or their avoidance of the project area.

PROPOSED

None.

CANDIDATE

The following candidate species may occur in the counties: -

Black tern (Chlidonias niger)
Bull trout (Salvelinus confluentus)
California bighorn sheep (Ovis canadensis californiana)
California floater (mussel) (Anodonta californiensis (Lea, 1852))
Columbia pebblesnail (fluminicola (=Lithoglyphus) columbianus (Hemphill in Pilsbry, 1899)) [great Columbia River spire snail]
Ferruginous hawk (Buteo regalis)
Harlequin duck (Histrionicus histrionicus)
Loggerhead shrike (Lanius ludovicianus)
Preble's shrew (Sorex preblei)
Spotted frog (Rana pretiosa)
Aster jessicae (Jessica's aster)
Calochortus nitidus (broad-fruit mariposa)
Haplopappus liatriformis (Palouse goldenweed)
Lupinus cusickii (Cusick's lupine)
Polemonium pectinatum (Washington polemonium)
Rubus nigerrimus (northwest raspberry)
Silene spaldingii (Spalding's silene)

ENDANGERED, THReaTENED, PROPOSED AND CANDIDATE SPECIES, AND CRITICAL HABITAT WHICH RAY OCCUR IN THE VICINITY OF ROZA DAN IN KITTITAS COUNTY, WASHINGTON, AS LISTED BY THE U.S. FISH AND WILDLIFE SERVICE
1-3-93-SP-345

LISTED

Bald eagle (Maliaeetus leucocephalus) - wintering bald eagles may occur in the
county from about October 31 through March 31.

Peregrine falcon (Falco peregrinus) - spring and fall migrant falcons may occur in the county.

Major concerns that should be addressed in your biological assessment of project impacts to listed species are:

1. Level of use of the project area by listed species.

2. Effect of the project on listed species' primary food stocks, prey species, and foraging areas and owl foraging, roosting, nesting, and dispersal habitat in all areas influenced by the project.

3. Impacts from project implementation and/or activities (e.g., increased noise levels, increased human activity and/or access, loss or degradation of habitat) which may result in disturbance to listed species and/or their avoidance of the project area.

Critical habitat for the northern spotted owl has been designated in the county.

PROPOSED

None.

CANDIDATE

The following candidate species may occur in the county:

Black tern (Chlidonias niger)
Bull trout (Salvelinus confluentus)
California bighorn sheep (Ovis canadensis californiana)
California wolverine (Gulo gulo luteus)
Columbian sharp-tailed grouse (Tympanuchus phasianellus columbianus)
Ferruginous hawk (Buteo regalis)
Harlequin duck (Histrionicus histrionicus)
Loggerhead shrike (Lanius ludovicianus)
Spotted frog (Rana pretiosa)
Western sage grouse (Centrocercus urophasianus phaios)
Astragalus columbianus (Columbia milk-vetch)
Delphinium viridescens (Wenatchee larkspur)
Erigeron basalticus (basalt daisy)
Lomatium tuberosum (Hoover's desert-parsley)
Sidalcea oregana var. calva (Oregon checker-mallow)
Silene seelyi (Seely's silene)
Tauschia hooveri (Hoover's tauschia)

ENDANGERED, THReaTENED, PROPOSED AND CANDIDATE SPECIES, AND CRITICAL HABITAT
WHICH MY OCCUR IN THE VICINITY OF THE CENTRALIA No. 1 & 2 PROJECTS
IN LEWIS COUNTY, WASHINGTON, AS LISTED BY THE U.S. FISH AND WILDLIFE SERVICE

LISTED
Bald eagle (Hallaeetus leucocephalus) - wintering bald eagles may occur in the
county from about October 31 through March 31.

There are 11 bald eagle nesting territories located in the county. Nesting activities occur from about January 1 through August 15.

Marbled murrelet (Brachyramphus marmoratus marmoratus) - may occur in the county.

Northern spotted owl (Strix occidentalis caurina) - may occur in the county of
throughout the year.

Peregrine falcon (Falco peregrinus) - spring and fall migrant falcons and nesting falcons may occur in the county.

Major concerns that should be addressed in your biological assessment of project impacts to listed species are:

1. Level of use of the project area by listed species.

2. Effect of the project on listed species' primary food stocks, prey species, and foraging areas and owl foraging, roosting, nesting, and dispersal habitat in all areas influenced by the project.

3. Impacts from project activities and implementation (eg., increased noise levels, increased human activity and/or access, loss or degradation of habitat) which may result in disturbance to listed species and/or their avoidance of the project area.

DESIGNATED

Critical habitat for the northern spotted owl has been designated in the county.

PROPOSED

None.

CANDIDATE

The following candidate species may occur in the county:

Black tern (Chlidonias niger)
Bull trout (Salvelinus confluentus)
Cascades frog (Rana cascadae)
Harlequin duck (Histrionicus histrionicus)

CANDIDATE (cont.)

Larch Mountain salamander (Plethodon larselli)
Mountain quail (Oreortyx pictus)
Northern goshawk (Accipiter gentilis)
Northern red-legged frog (Rana aurora aurora)
Northwestern pond turtle (Clemmys marmorata marmorata)
Olympic mudminnow (Novumbra hubbsi)
Spotted frog (Rano pretiosa)
0elphinium leucophaeum (pale larkspur)

ATTACHMENT B

FEDERAL AGENCIES' RESPONSIBILITIES UNDER SECTIONS 7(a) AND 7(c)

OF THE ENDANGERED SPECIES ACT OF 1973, AS AMENDED

SECTION 7(a) - Consultation/Conference

Requires:

1. Federal agencies to utilize their authorities to carry out programs to conserve endangered and threatened species;

2. Consultation with FWS when a federal action may affect a listed endangered or threatened species to ensure that any action authorized, funded, or carried out by a federal agency is not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of critical habitat. The process is initiated by the federal agency after it has determined if its action may affect (adversely or beneficially) a listed species; and

3. Conference with FWS when a federal action is likely to jeopardize the continued existence of a proposed species or result in destruction or an adverse modification of proposed critical habitat.

SECTION 7(c) - Biological Assessment for Construction Projects *

Requires federal agencies or their designees to prepare a Biological Assessment (BA) for construction projects only. The purpose of the BA is to identify any proposed and/or listed species which is/are likely to be affected by a construction project. The process is initiated by a federal agency in requesting a list of proposed and listed threatened and endangered species (list attached). The BA should be completed within 180 days after its initiation (or within such a time period as is mutually agreeable). If the BA is not initiated within 90 days of receipt of the species list, please verify the accuracy of the list with our Service. No irreversible commitment of resources is to be made during the BA process which would result in violation of the requirements under Section 7(a) of the Act. Planning, design, and administrative actions may be taken; however, no construction may begin.

To complete the BA, your agency or its designee should: (1) conduct an onsite inspection of the area to be affected by the proposal, which may include a detailed survey of' the area to determine if the species is present and whether suitable habitat exists for either expanding the existing population or potential reintroduction of the species; (2) review literature and scientific data to determine species distribution, habitat needs, and other biological requirements; (3) interview experts including those within the FWS, National Marine Fisheries Service, state conservation department, universities, and others who may have data not yet published in scientific literature; (4) review and analyze the effects of the proposal on the species in terms of individuals and populations, including consideration of cumulative effects of the proposal on the species and its habitat; (5) analyze alternative actions that may provide conservation measures; and (6) prepare a report documenting the results, including a discussion of study methods used, any problems encountered, and other relevant information. Upon completion, the report should be forwarded to our Endangered Species Division, 3704 Griffin Lane SE, Suite 102, Olympia, WA 98501-2192.

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* "Construction project" means any major federal action which significantly affects the quality of the human environment (requiring an eis), designed primarily to result in the building or erection of human-made structures such as dams, buildings, roads, pipelines, channels, and the like. This Includes federal action such as permits, grants, licenses, or other forms of federal authorization or approval which may result in construction.

Appendix E. Environmental Impacts of Generic Resource Types

Alternative Resource Types
Chapter 3
(This text was reproduced from BPA's 1992 Resource Program eis)

Chapter 3 Alternative Resource Types: Description, Environmental Effects, and Mitigation Measures

This chapter describes the potential environmental effects and mitigation for the resource types available for meeting load. With the exception of nuclear, all of the resource types described are generic resources. The cost and supply projections for these conservation and generating resources are also included. The detailed assumptions and model inputs used for each resource type in Chapters 4 and 5 are included in the supply curves that are contained in Appendix D. Data presented for the Final eis in this chapter have been revised in response to comments on the Draft eis and for consistency with assumptions used in Chapters 4 and 5.

Figure 3-1 compares the resource types against each other for several important environmental impacts. The impacts of each resource are described in more detail in the remainder of this chapter.

3.1 Conservation Resources

Conservation includes a wide range of methods to save energy and capacity in the commercial, residential, industrial, and irrigation and agriculture sectors.

Conservation programs can provide both capacity and energy savings.

Each program needs to be evaluated as to how it may impact the load. Some conservation programs reduce load only during off-peak hours and would have little or no capacity savings. Other conservation programs provide load reduction primarily during peak hours and would provide substantial capacity savings. A simple way to evaluate capacity savings from conservation programs is to compare the ratio of load reduction during peak hours to the total load reduction multiplied by the monthly energy savings. Detailed examples of capacity calculation for conservation programs have been developed for Billing Credits at BPA.

The potential environmental effects of conservation programs vary considerably. Figure 3-2 provides an overview of the pathways for environmental impacts; the following sections describe impacts by individual sector.

Figure (Page E3 Figure 3-1 Selected Environmental Impact of Conservation...)

Figure (Page E4 Figure 3-2 Environmental Effects and Mitigation - Conservation)

General Environmental Impacts

Indoor air quality has been the principal environmental impact of concern for energy conservation. The quality of the air inside a house or building is influenced by the sources of airborne pollutants (either from outside or within the building), as well as interaction between pollutants themselves, the building's internal environment (temperature, humidity, ventilation rate, biological contaminants), and any cleaning or filtration of either the internal or external air. Internal sources of pollutants include building materials and furnishings (e.g., paint, adhesives, furniture, and carpet), and activities within a building, such as photocopying or cooking.

People may spend as much as 90 percent of their time indoors. That time is spent in buildings with increasingly tight envelopes (the building's floors, walls, ceilings, and roof, including openings such as doors, windows, and other gaps).

Human health may be affected by indoor air quality. Effects include cancer, Legionnaire's disease, headaches, eye/nose/throat irritation, nausea, sensitivity to odors, dizziness, neurotoxic symptoms such as difficulty in concentrating, skin irritation, and odor and taste complaints.

Some of the impacts to human health may be caused by inadequate ventilation; microbiological contamination from dampness or from a building's chillers or humidifiers, or toxins released by those organisms; materials released by biocides used to control growth organisms; lighting levels; noise; naturally occurring radon gas; or some combination of these factors. Some studies have determined that improved ventilation could eliminate most indoor air quality problems. Others have concluded that a combination of factors governs.

Most existing homes and buildings potentially have indoor air quality problems. Many were built before any standards or regulations for indoor air quality existed.

In most studies, naturally ventilated buildings exhibit the lowest-prevalence of problems but are least efficient in energy conservation. Air quality in so-called - "tight" homes and buildings, on the other hand, may be dominated by the building's ventilation system and the activities of the building's occupants.

Other environmental concerns include disposal of potentially hazardous materials removed from existing buildings during conservation remodels or retrofits (see 3.1.1); and preservation of the character of historic buildings receiving conservation improvements, discussed below.

Historic Preservation.

Buildings of potential historical, architectural, or cultural significance, including buildings more than 45 years old, potentially could be affected, or have their significance reduced or reined, by the application of energy conservation measures. The ECM could affect the appearance of either the building exterior or interior, if the interior is significant. The inclusion of uncharacteristic features, design, materials, colors, or equipment (if visible) could potentially degrade the value of a significant building. Adding vestibules or awnings, inappropriate fixtures, wrong-colored materials such as caulking, nonperiod equipment such as timeclocks and thermostats, inappropriate windows or doors, and insulation treatments that are obtrusive are examples of actions that might conflict with the significance of a building, depending on the measure and how it is installed.

Recognizing that implementation of BPA's conservation programs could affect historic buildings, BPA entered into an agreement to protect the cultural resource values of such buildings. In 1983, BPA, the Advisory Council on Historic Preservation, and the State Historic Preservation Officers of California, Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming signed Programmatic

Memoranda of Agreement which specified procedures for ensuring that BPA's energy conservation programs were consistent with historic preservation values and that the review requirements of the National Historic Preservation Act were fully satisfied.

Current Legislation.

BPA first entered the arena of indoor air quality at a time when no legislation or regulation existed. Now EPA and the states are developing laws and standards. BPA's programs strive to be consistent with and to complement these efforts.

The EPA has begun a multi-year effort to look at the cost implication of a number of indoor air quality control strategies. Several program initiatives are underway within the EPA to improve utilization of the Toxic Substances Control Act

(TSCA) and the Federal Insecticide, Fungicide, and Rodenticide Act, as amended (FIFRA) statutes (see Chapter 6) and to integrate them within the broad framework of indoor air exposures.

Since 1989, the budget of the Indoor Air Division, the group responsible for EPA's indoor air policy and programmatic activities, has grown substantially. The President's FY 1992 budget would enhance the Agency's ability to focus on these indoor air quality research areas: health effects; source assessment and control; building studies and methods; risk assessment; and development of a biocontaminant control program.

3.1.1 Commercial Sector Conservation Resources Program Description

Conservation in commercial buildings consists of increasing energy use efficiency. Each facet of a building's design, construction, operation, and maintenance can affect its energy efficiency. Opportunities for conservation or increased energy efficiency in existing buildings may be via either upgrades of single features or systems; such as lighting, or through renovations, remodels, or major retrofits, where the interior of a building may be gutted and entirely new mechanical, electrical, or structural features are installed. New buildings are designed to be as energy efficient as is warranted.

The commercial sector conservation resource consists of 11 generic building types including large and small office buildings, large and small retail buildings, restaurants, elementary and secondary schools and colleges, warehouses, grocery stores, health care facilities, lodging facilities, and a miscellaneous category. Office and retail buildings account for the largest share of energy use, since they make up the biggest share of commercial building floor space. The largest potential for energy savings is in lighting and heating measures.

Energy Conservation Measures

Energy-consuming end uses within these building types include lighting, power systems, building shell (envelope), heating/air conditioning, ventilating, refrigeration, domestic water heating, and other uses including "plug loads" such as task lighting and personal computers. A complete list of ECMs is included in Appendix C.

Lighting Measures.

Lighting measures provide light or illumination for the various needs within (or outside of) a building. Lighting measures consist of fixtures, ballasts, lamps, reflectors, and lighting controls. Fixtures, or luminaires, hold all of the components. Fixtures may incorporate the most advanced design of reflectors, getting the most light produced by a fixture to the object, area, or task needing light. Ballasts, if

needed, may be magnetic, hybrid, or electronic, the latter being the most efficient. Ballasts provide starting current for and limit current flow to fluorescent lamps, while consuming some power themselves. Lamps are the light source and they may be incandescent, fluorescent, high-intensity discharge (mercury vapor, metal halide, or high-pressure sodium) or low-pressure sodium. Lighting systems are designed and analyzed for the most efficient layout, use, and control. Daylighting, the use of natural daylight, is another strategy to conserve energy by limiting the use of artificial lighting.

Power Systems.

In power systems, conservation measures consist of actions such as disconnecting lightly loaded transformers, replacing transformers, upgrading to higher voltage systems, use of appropriately sized motors, use of variable speed drives, and controls of these devices.

Building Envelope.

Envelope measures consist of insulation in a building's ceiling, walls, floors, foundation, crawl space, or slab. Infiltration measures such as weatherstripping or caulking also are considered envelope measures. Some door and window technology also falls into this category and affects the efficiency of the building shell energy use.

Heating/Air Conditioning.

These measures affect a building's cooling systems, equipment, and controls. High-efficiency equipment, alternative cooling systems, insulation of equipment, control of systems, and variable air volume systems might all be used to conserve energy in a commercial building.

Ventilation.

Ventilation affects a building's equipment and/or its use because it affects air uptake and circulation, and the control of the system. Sensors, the amount of air used, and circulation equipment such as fans, dampers, or air destratification devices are examples of energy conservation measures.

Refrigeration.

Conservation measures dealing with refrigeration include efficient equipment for the production and movement of chilled water or refrigerant such as pumps, compressors, chillers, exhaust heat recovery, and variable speed drives, as well as systems for control of the equipment.

Domestic Hot Water.

These measures provide better insulation of equipment, alternative heating systems, and controls.

Operating Characteristics and Capacity Contribution

Impacts of commercial conservation programs on capacity depend on the types of energy-consuming equipment present within commercial buildings and their operating schedules. These two factors vary depending on the type of building and whether it is a retail store, office, school, or other type of facility.

Generally, the greatest opportunities for conservation programs are indoor lighting and heating ventilation and cooling (HVAC) system, which usually consume the most electricity in commercial buildings. The electricity demanded from these two end uses are generally regarded as major contributors to load at the time of system peak demand. Therefore, conservation programs directed toward them should reduce peak demand. Peak savings have typically been estimated as being proportional to energy savings.

Environmental Effects and Mitigation

The potential environmental effects associated with installing energy conservation measures in commercial buildings and suggested mitigation techniques are summarized below.

Table 3-1 Commercial Conservation Measures and Their Impacts

Measure	Effect	Impact or Concern
Lighting Systems	Replacement or installation of equipment	PCBs, mercury, glare, safety
Power Systems	Replacement with high-efficiency equipment	None expected
Building Envelope	Insulation, windows, doors, infiltration measures	UFFl, asbestos, IAQ
Heating, Ventilation, and Air Conditioning	Efficient equipment, operational changes, insulation, controls, operation	Chemicals, CFCs, IAQ

Refrigeration	Controls, equipment, operation	CFCs
Domestic Hot Water transfer	Insulation, operation	Toxic fluids

Lighting Systems

High-pressure sodium (HPS) lamps are an extremely bright source o! light. They can offer a highly efficient and long operating life in selected indoor applications. Although lighting technology is rapidly changing, there are still some environmental concerns associated with the use of HPS indoors. They include glare, which can cause annoyance or affect visual performance; stroboscopic ("flicker") effect, in which rapidly moving objects may appear to be stationary; and color distortion. These effects are related primarily to safety. There are no known long-term health effects. Low-pressure sodium (LPS) lighting produces monochromatic light (yellow or gold tint), which distorts color such that is not recommended for indoor use.

Proper installation of HPS mitigates the effects. Glare can be reduced or eliminated through proper placement of the lights, and by use of either a refractor lens or other HPS lamps that have been specifically designed for mounting at low heights. Other types of supplementary task light can be used to help reduce or eliminate reflected glare. In work areas where flicker could present a safety hazard, HPS lighting should use three-phase power and luminaires that produce overlapping illumination. By wiring each adjacent luminaire on a separate phase, the stroboscopic problem can be reduced or eliminated. Earthtone colors with a dull or matte finish can be used on surfaces to improve color rendition. However, if critical, color-dependent tasks are involved, HPS lighting should not be used. Any signs or signals conveying health and safety information (e.g., exit or caution signs) can be illuminated independently by other light sources such as incandescent, fluorescent, or metal halide.

As energy-efficient lighting programs gain in popularity, the risk of contamination at landfills increases with the increased disposal of used lamps.

Recent studies suggest that the lead solder used in the base of lamps, because of

its highly toxic nature, may cause most lamps to be classified as a hazardous waste.(1) The quartz arc tubes in mercury vapor and metal halide lamps contain small amounts of mercury, ranging from 20 milligrams in a 75-watt lamp, up to 2,500 milligrams in a 1,000-watt lamp. In addition, all fluorescent lamps contain mercury. A 4-foot fluorescent lamp typically contains 35 to 50 milligrams of mercury, well above the Federally regulated level of 20 milligrams. According to Fred Bryant of Mercury Technologies Inc., Benicia, California, it takes 10,000 4-foot fluorescent lamps to yield 1 pound of mercury. Only a few teaspoons of mercury can poison a lake for centuries. (2)

Both mercury and lead are highly toxic and poisonous to living organisms. Mercury and lead poisoning can lead to chronic renal failure. Chronic exposure to or ingestion of practically any heavy metal, such as mercury or lead, may lead to multiple abnormalities to the nervous system. Concern is growing about the ground and water contamination that may result as municipal landfills continue to accept lighting refuse.

In addition to the threat of used fluorescent lamps contributing to ground contamination by lead and mercury, fluorescent light ballasts manufactured prior to 1978 may contain polychlorinated biphenyls (PCBs). PCBs are a probable human carcinogen suspected of causing excess risk of liver cancer in humans by ingestion, inhalation, or skin contact. Prior to 1979, PCBs were widely used as coolants in electrical equipment, including the capacitors used in fluorescent light ballasts. The capacitors in those fluorescent ballasts contain 1 to 2 ounces of near-pure PCBs. If the ballast fails, the capacitor may break open, allowing the PCB oil to leak. Under the Toxic Substances Control Act of 1976, leaking ballasts must be disposed of either through high-temperature incineration or in an EPA-approved chemical waste landfill. Disposal of small quantities of non-leaking fluorescent ballasts containing PCBs is not Federally regulated, but EPA, Region 10, has developed and adopted a policy for disposal of five or more PCB-laden light ballasts. The EPA has published a fact sheet, "PCBs in Fluorescent Light Fixtures," which provides basic guidelines for handling and disposing of ballasts containing PCBs. The EPA as also currently reviewing its methods for testing the potential hazards caused by the disposal of used fluorescent lamps. As of January 1992, EPA had no specific regulations on disposal of lamps.

Building Envelope

Urea formaldehyde foam insulation (UFI) has, in the past, been used to insulate buildings. UFFI contains gaseous material and releases residual-free formaldehyde as it ages. This may contribute to adverse health affects for building occupants. However, formaldehyde-containing products are no longer available and have been replaced with such products as cellulose with fire-retardants. Tightening of the building shell may lead to changes in indoor air quality. Mitigation for this concern is discussed in the following section.

Insulation or other construction materials in some buildings may contain asbestos. Asbestos fibers are very small (less than 10 microns long), very strong, and very resistant to heat and chemicals. Since they are so resistant, they are also

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(1) Options for Handling Noncombustion Waste, Revision 1, Electric Power Research Institute report SG-7052-Rev. 1, prepared by Mittelhauser Corporation, Laguna Hills, CA, April 1992, pg. 3-7.

(2) Tracy, Jim. Hidden Cost of Relamping, Home Energy - Trends in Energy, May/June 1992, p. 10.

extremely stable in the environment. They do not evaporate into the air, dissolve in water, or disintegrate over time. Intact and undisturbed asbestos materials do not pose a health risk. However, the adverse health effects resulting from exposure to airborne asbestos fibers are well documented. Asbestos is a known carcinogen and can lead to other respiratory ailments. Stringent Federal, state, and local waste disposal procedures and regulations govern asbestos disturbance and removal. Removing or altering building structures that contain asbestos must be done in compliance with those laws and regulations.

Fiberglass insulation used in commercial ductwork may increase worker and occupant exposure to synthetic fibers. It is not clear if such exposure is linked to health effects. (Baechler, et el., Environmental Effects and Mitigation for Energy Resources, 1990.)

Heating, Ventilation, and Air Conditioning Systems

Changes to the heating, ventilation, and air conditioning systems may affect air quality inside buildings. Various pollutants are released within any commercial building on a continuing or intermittent basis. Indoor pollutants can originate from objects within a building, from building materials, from indoor activities of building occupants, or from building occupants themselves. Outdoor air pollutants enter buildings through mechanical ventilation systems or through infiltration. A reduction in the flow of outside air into a building may cause these pollutants to accumulate at levels that could cause health problems for building occupants.

Energy-efficient designs can be installed such that indoor air quality is not adversely affected. The American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) has developed ASHRAE Standard 62-89, "Ventilation for Acceptable Indoor Air Quality." It states that acceptable indoor air quality is achieved when there are no known contaminants at harmful concentrations according to the proper authorities, and when fewer than 20 percent of people exposed express dissatisfaction with the air. In a 1991 ea (Approaches for Acquiring Energy Savings in Commercial Sector Buildings. DOE/BPA-0513), BPA used the ASHRAE 62-89 standards as a basis for proposing programs. In mechanically ventilated buildings, the outside air requirements specified in this standard should be incorporated. Equipment can be designed based on assumed occupancy for the building or on ASHRAE Standard 90.1, "Occupancy Density." For naturally ventilated buildings, ventilation rates must comply with local building codes.

Some types of projects (e.g., direct application geothermal or ground water heat pumps) may involve the use of subsurface resources and could impact water soil quality. For example, ground water heat pumps could contaminate groundwater or soil if toxic heat transfer fluids leak or accidentally discharge. However, non-toxic solutions are available. Ground source heat pumps draw heat from the soil, causing the ground to freeze sooner than would be expected under normal conditions.

Various Federal, state, and local regulations govern the use of subsurface resources. Those regulations are intended to minimize the impacts on land and water. Letters of coordination and/or approval from appropriate agencies can be obtained through consultation prior to installing any energy conservation measure which could affect subsurface resources.

Domestic Hot Water Systems

Some types of commercial ECMs (i.e., solar domestic water heating systems or water source heat pumps) require the use of transfer fluids. These fluids, such

as ethylene glycol, may be toxic and could contaminate the ground water or soil if leaks or accidental discharges occur.

Substituting non-toxic transfer fluids for the toxic fluids can eliminate concern for contamination. In addition, some state or local codes may prohibit the use of certain toxic transfer fluids. Consequently, local code officials should be contacted prior to installing energy conservation measures that require the use of transfer fluids.

Supply Forecast

To effectively evaluate commercial energy conservation, BPA evaluated the effects of a mix of energy conservation measures (ECMs) and the amount of equipment that would be replaced by the installation of a new technology, given forecasts of regional electricity savings potential. To accomplish this, BPA supplied a base case forecast to Battelle Pacific Northwest Laboratory, which developed a tool called ECMMIX.

Basically, ECMMIX selects energy conservation measures until a specified megawatt target is achieved. The model estimates the number of ECMs and the amount of replaced technology that corresponds to a particular forecasted regional savings potential. The savings rate per thousand square feet, adjusted by fuel share sensitivities and line-loss credits, is multiplied by the prototypical building floor size, resulting in a savings rate per building type. Regional savings potential then is converted to kilowatt-hours. The kilowatt-hours, divided by savings rate per building, yields an estimate of the number of buildings corresponding to the savings potential. The number of ECMs, applied to the number of buildings, yields an estimate of the number of ECMs needed to achieve the forecasted savings potential. This also yields the number of ECMs replaced as each ECM is installed.

For the purposes of this model, ECMs also are categorized by timing opportunity, e.g., whether remodel, renovation, lost opportunity, or discretionary. Lost opportunities correspond to ECMs that can only be adopted during construction or when a building undergoes major renovation or remodeling. Discretionary opportunities can occur at any point in the life cycle of an existing structure.

Table 3-2 Conservation Resource Supply for Commercial Sector Program

Program (Sector/Sub-sector)	Total Supply by 2010 (aMW) (1)	BPA Supply by 2010 (aMW)
New Buildings	601	222

Existing Buildings - Discretionary	158	84
Existing Buildings - Lost Opportunity	149	72

(1) Achievable conservation potential under the 1989 final high load forecast.

Table 3-3 Conservation Resource Supply for Commercial Sector Program Under High Conservation Alternative

Program (Sector/Sub-sector)	Total Supply by 2010 (aMW) (1)	BPA Supply by 2010 (aMW) (1)

Program (Sector/Sub-sector)	Total Supply by 2010 (aMW) (1)	BPA Supply by 2010 (aMW) (1)
New Buildings	1,760	650
Existing Buildings - Discretionary	158	86
Existing Buildings - Lost Opportunity	149	67

(1) Achievable conservation potential under the 1989 final high load forecast.

Cost

The projected costs for the commercial conservation programs under all alternatives analyzed in this RPeis are contained in Table 3-4.

Table 3-4 Conservation Resource

Regional Cost(1) for Commercial Sector Program

Program (Sector/Sub-sector)	Cost per MW (2) (1988$) (000)
New Buildings	$1,876
Existing Buildings - Discretionary	$2,876
Existing Buildings - Lost Opportunity	$2,737

(1) Figures represent the regional costs of conservation, which are the sum of BPA, utility, and customer expenditures. These figures represent costs over the life of the programs (see Table D-7, Resource Lifetimes, Volume 2: Appendices of the Draft Environmental Impact Statement - Resource Programs, March 1992).

(2) Includes a 7.5 percent transmission line loss credit. Cost per unit includes administrative costs, in 1988 constant dollars, associated with acquisition of conservation resources. Operating costs are included in the cost of installation, as are administrative costs for BPA and utilities.

3.1.2

Residential Sector Conservation Resources Program Description

Residential conservation includes a wide variety of approaches to reducing electricity use requirements, such as house tightening through insulation, storm windows, passive solar design, earth-sheltered housing, and many potential appliance efficiency measures. Within the residential sector, conservation programs promote retrofitting existing homes to make them more energy efficient and building new homes to meet or exceed current standards. Some conservation programs may also promote the use of energy-efficient appliances and devices.

The residential sector conservation resource includes single family dwellings, multifamily dwellings, and manufactured homes.

Energy Conservation Measures

When retrofitting existing homes, weatherization measures such as ceiling insulation, floor insulation, storm windows, unfinished-wall insulation, duct insulation, storm doors, caulking, weatherstripping, clock thermostats, dehumidifiers, and electrical outlet and switchplate gaskets can be installed.

Conservation measures in energy-efficient new homes are installed through various construction techniques that tighten the building structure to reduce air infiltration and heat loss. These include many of the weatherization materials described above.

Beyond building envelope measures, there are numerous other measures that can be installed in residential structures. Other conservation measures are grouped into the following general categories: lighting, other appliances, space heating, and solar devices.

Operating Characteristics and Capacity Contribution

Conservation programs that reduce electrical energy consumption in the residential sector tend to result in corresponding reductions in peak loads. Typically, reductions in peak are assumed to be proportional to the reductions in energy use.

Residential programs - space and water heating measures: These two end uses are major contributors to system peak demand. Residential programs are primarily directed at improving space and water beating efficiency, and therefore are beneficial in reducing peak loads and increasing capacity.

Residential programs - lighting and appliances. Programs that promote energy efficient appliances and lighting efficiency also reduce loads at the time of system peak. However, the capacity contribution from these end uses are of lesser magnitude than the contributions from space and water heating.

Environmental Effects and Mitigation

The environmental effects of conservation measures are largely beneficial. Yet, to some extent, virtually all conservation measures may have effects on the environment which are adverse or undesirable.

BPA prepared an environmental impact statement in 1984 for its retrofit residential weatherization programs (DOE/eis-0095F), and one in 1988 for its new energy-efficient homes programs (DOE/eis-0127F). Conclusions from these documents and other relevant information are summarized in Table 3-5 and in the discussion below.

Lighting

Compact fluorescent lights may break more often than incandescent bulbs when being installed or from lamps falling over, and breathing the gases contained inside these bulbs may be hazardous. Also, disposal of bulbs and ballasts of these and of standard fluorescents are an environmental concern because the bulbs potentially contain toxic mercury gas, which could be hazardous if inhaled. (See section 3.1.1, above.) Potential contamination from disposal of large quantities of mercury-containing bulbs can be reduced by using handling Procedures in accordance with hazardous waste regulations. The problem of disposing of ballasts with radioisotopes can be avoided by using electronically-ballasted lights, which do not use radioisotopes for starting. Low-pressure and high-pressure sodium and metal halide bulbs last longer than standard bulbs, thus reducing the waste stream.

Table 3-5 Residential Conservation Measures and Their Impacts

Measure	Effect	Impact or Concern
Building Envelope		
Insulation Ceiling, attic, walls, floors, ducts	Reduces energy requirements	Asbestos, CFCs
Infiltration Measures Storm and thermal windows and doors, caulking, weatherstripping	Reduces energy requirements	IAQ
Ventilation Systems	Heat recovery	IAQ

		concerns
None	Energy Use Efficiency Compact fluorescent lights, energy-efficient appliances (e.g., refrigerators, freezers, etc.)	Reduces energy requirements
None	Heating System Efficiency Hydronic pipe insulation, clock & other energy-saving thermostats, heat pumps	Reduces energy requirements
Scalding	Water Heating Efficiency Water heater wraps, low-flow showerheads, pipe insulation- exhaust air heat pumps, thermostats	Reduces energy requirements
Battery handling when used for residential systems	Solar	Reduces energy requirements

Building Envelope

Tightening measures to reduce the air exchange rate in residences may cause increased indoor air pollution concentrations, thus increasing the risk of adverse health effects to the occupants. However, measures such as insulation, clock thermostats, and dehumidifiers have little or no effect on indoor air quality.

BPA prepared an eis in 1984 (The Expanded Residential Weatherization eis [DOE/eis-0095f]) and an eis in 1988 (Final Environmental Impact Statement on New Energy-Efficient Homes Programs [DOE/eis-0127F]) to examine the potential environmental effects of implementing residential weatherization and new homes programs for all electrically heated homes in the region. Major effects examined pertained to indoor air quality and human health.

The primary concerns focused on radon and formaldehyde. Other indoor pollutants, such as respirable suspended particulates (RSP), combustion gases, household chemicals, moisture, and microorganisms, also raised concerns, but review of the scientific literature indicated insufficient information to accurately quantify the health effects of these pollutants.

Scientists have found that formaldehyde can cause severe short-term health effects, although these effects are not quantifiable and sensitivity among exposed persons differs. The key health effects for indoor air pollutants are lung cancer from exposure to radon, and nasal cancer from formaldehyde.

Most formaldehyde impacts can be mitigated by simply avoiding building materials or other products that contain urea formaldehyde glues or adhesives.

Radon.

Radon comes primarily from uranium-bearing soil. Entry into homes is predominantly caused by natural forces such as pressure gradients, wind, and air temperature, not by house tightening techniques, as was postulated in the 1984 eis.

There are many new state and Federal requirements, laws, and standards regulating indoor air quality. Thus, from BPA's perspective, monitoring for radon may no longer be necessary as a program requirement in tracking potential environmental impacts. The extent of BPA's responsibility due to its weatherization programs is also questionable, as studies have revealed that there is no direct correlation between house tightening and radon levels (Radon and Remedial Action in Spokane River Valley Homes, USDOE/BPA, 1987). Indoor radon levels depend on several other factors that do have direct correlations, including air temperature, atmospheric pressure, wind direction, source concentration, soil permeability, and soil moisture content. As radon levels are now recognized as source-driven, house tightening and weatherization are not the determining factors.

Many new radon mitigation techniques have become available since the preparation of BPA's 1984 and 1988 eiss.

Although all alternative construction techniques (pathways) described in the

1988 Final eis required a radon package for new homes, which included the offer of radon monitoring to all households, it also included the option of installing measures (a ventilated crawlspace and/or a gravel base under a concrete slab floor) for more effective mitigation of radon if the homeowner chose. Those new homes for which builders did not install these measures for post-construction source control require monitoring for radon.

The effectiveness of mitigation methods may vary, due to daily or seasonal changes in environmental factors or in the operation of the building and mechanical systems within it. These mitigation methods usually lower indoor radon levels; however, the final time-averaged concentration is not always predictable. Of the mitigation techniques studied over the past several years, five basic radon control techniques are considered to be the most effective. These techniques are:

* Subsurface ventilation
* Passive Stack Ventilation
* Block wall ventilation
* Air-to-air heat exchanger
* Basement overpressurization
* Caulking of cracks and openings

As described below, each of these techniques can be effective when applied under appropriate conditions and radon concentrations. Source control and the other methods rely on either mitigation after the fact or a combination of source and concentration dilution to achieve results.

Subsurface Ventilation.

Subsurface ventilation has the potential to be the most effective when a building is on a concrete foundation or basement slab. Basic subsurface ventilation consists of one or more ventilation pipes installed through the subfloor and into the ground under the foundation and extending to the outside of the building. The result is an unrestricted ventilation hole coupling the ground with the outside air. A small air pump is typically attached to the ventilation pipes to provide either a negative or positive pressure gradient between the interior building space and the subfoundation perimeter. This technique is intended to prevent the migration of radon gas into the building space. If the initial interior concentration of radon is kept to a minimum, further mitigation should not be necessary. Test results to date show that a significant reduction of indoor radon concentrations can be achieved through proper subsurface design.

Passive Stack Ventilation.

This ventilation system is very similar to the active systems previously described, with the exception of the mechanical pump. On a passive system, natural pressure gradients and existing "stack effects" are the driving forces for providing a negative pressure flow out of the ground under the concrete slab. The overall effectiveness of passive stack ventilation has not yet been fully determined. BPA, the Environmental Protection Agency, and the Washington Department of Health are beginning a study to determine its actual effectiveness. This technique is expected to offer some reductions In radon in homes.

Block Wall Ventilation.

Block wall ventilation is a technique used when concrete building blocks are used for basement or structural walls. The interior cavities of the blocks are used as ventilation sinks. An active system is installed such that air is removed from the block cavities. This technique, if property designed and controlled, results in varying success as a mitigation tool.

Air-to-Air Heat Exchangers.

Air-to-air heat exchangers are limited to situations where the indoor radon concentration is not extreme. Because most of these systems are designed to provide a maximum of 0.5 air changes per hour, mitigation of high levels of radon would not be effective. Basement installations are one of the most effective applications of air-to-air heat exchangers. When a basement can be isolated from the remaining building by closing doors and sealing cracks, fairly effective mitigation can be achieved by ventilating only the basement area. Typically, if the lowest level of a building can be mitigated, the remainder of the building will be similarly affected.

Basement Overpressurization.

Basement overpressurization is a variation of subsurface pressurization in which the basement area, rather than the subfloor ground area, is pressurized. This technique has shown positive results, but the basement must be isolated and closed off or the technique is overridden.

Caulking.

Caulking of cracks and openings has very limited application and mitigation effect. If the initial concentration of radon is low, this technique may prove to be the most cost effective. If radon levels are moderate to high and other circumstance are present, caulking and sealing may not prove reliable. It would, however, be a complementary technique for a more active approach, such as basement overpressurization.

Although weatherization activities do not appear to be determining factors in residential radon levels, BPA continues to monitor radon legislation.

Indoor Radon Abatement Act of 1988 (IRAA). Several key authorities in IRAA expired in 1991 and additional discussion is anticipated on this topic. EPA and the states are taking the lead in setting standards, developing codes, and establishing monitoring and mitigation requirements.

In fulfilling its responsibilities under IRAA, EPA has several activities under way or in various stages of completion:

Conducting national surveys in homes, Federal buildings, and schools to characterize radon exposure levels.

Providing grants to states to establish and enhance their radon programs.

Operating four regional training centers to train states and the private sector on the latest advances in diagnosing, mitigating, and preventing radon entry in buildings.

Operating two voluntary proficiency programs that evaluate radon contractor capabilities and provide lists of qualified firms to states and consumers.

Developing model construction standards that will prevent radon entry in new buildings.

Recommending that all levels below the third floor of a building be tested for radon, and that appropriate corrective measures be taken.

Proposed Legislation.

Several proposals have been put before the state and/or Federal legislative bodies that deal with further regulation of indoor air quality. EPA and the states are playing a strong role in mitigating any potentially harmful health effects of radon. BPA's programs have been designed to complement any mitigation requirements imposed by state or Federal legislation.

In the fall of 1991, comprehensive indoor air quality legislation was put before the U.S. Senate (S. 455; S. 792) and the House of Representatives (H.R. 1066; H.R. 1693; H.R. 1793). S. 792, the Indoor Radon Abatement Reauthorization Act of 1991, was intended to expand the original legislation in a number of areas.

H.R. 1793 was intended to ensure that amounts paid for home improvements to mitigate radon gas qualify for a tax deduction. H.R. 1693, the National Radon in Schools Testing Act of 1991, amends the Toxic Substances Control Act and requires local education agencies to submit radon test results to the governor, who must submit a report to the EPA. Provisions similar to S. 792 have also been introduced in the House. Because of the persistent introduction of new bills in both the House and the Senate concerning indoor air quality, it is highly likely that further Federal and state action can be expected. H.R. 3258, introduced in 1992 and approved in committee, is designed to improve the accuracy of radon testing products and services and create a commission to increase public awareness of radon, to provide grants to state-run radon programs, and to reauthorize EPA's radon programs.

Appliances

Chlorofluorocarbons (CFC) used in refrigerators and freezers, and foam insulation with CFC blowing agents, may be harmful to the global environment.

Similarly, any water heater or condensation dryer employing a heat pump can possibly allow the refrigerant to escape into the environment. However, as of July 1, 1992, the Clean Air Act does not allow venting of refrigerants.

The impacts from CFCs in refrigerators, freezers, and appliances that contain a heat pump can be reduced by recovering and recycling the refrigerant.

Space Heating

Integrated hot water/space heat systems can experience backdrafting in units that do not use power venting or seated combustion. Air-to-air heat exchangers can cause moisture-related problems, including mold, mildew, and wood decay, when they fail to exhaust humidity to the outdoors. Such recapturing of humidity can allow the transfer of dissolved pollutants (such as formaldehyde) to the incoming air.

Possible effects associated with backdrafting can be eliminated by using power venting or sealed combustion in integrated combustion appliances. Heat exchangers that are properly installed with units that are not oversized for the house eliminate many of the problems of moisture retention and backdrafting.

Improving thermal distribution systems in homes can help to reduce or eliminate pressure imbalances and improve indoor air quality, energy consumption, and comfort.

Exhaust air heat pumps can increase the potential for backdrafting and increased radon entry into the home where radon is a problem. Air-source heat pumps pose environmental problems to the earth's ozone layer when their refrigerants are allowed to escape. High-efficiency models have been found to be the source of odors in the home. Variable-speed models can cause moisture problems by maintaining different temperatures in different areas of the house if not operated properly.

Scrubbing the fan coils of high-efficiency heat pumps with bleach can remove house odors associated with these units; however, care must be taken to ensure bleach fumes do not affect the indoor air. Refrigerants used in heat pumps should be recycled properly to avoid escape into the atmosphere.

Solar

Solar access in itself has minimal adverse environmental effects. The major environmental impact of residential photovoltaic (PV) systems involves the batteries; handling of the acidic electrolyte contained in these batteries can have: adverse health effects. Proper care and disposal of PV batteries is essential to avoid accidents and environmental damage.

Well-designed passive solar houses should have no major adverse environmental impacts, but active systems may pose problems, depending on the kind of heat storage material used. Mold and mildew can grow on storage rocks and be distributed throughout the house via a forced air system. Noxious or harmful outgassing can also occur. Materials for storage bins must be selected with care to avoid those that might enhance mold and mildew growth or cause health hazards.

Supply Forecast

Table 3-6 contains the estimate of total residential conservation achievable by 2010 for all alternatives except the High Conservation Alternative. Table 3-7 contains the projected total supply under the High Conservation Alternative.

Table 3-6 Conservation Resource Supply for Residential Sector Programs

Program (Sector/Sub-sector)	Total Supply by 2010 (aMW) (1)	BPA Supply by 2010 (aMW)

Existing Single Family Weatherization	102	62
Existing Multi-Family Weatherization	36	9
New Single-Family MCS	260	144
New Multi-Family MCS	37	12
Water Heaters	345	152
Refrigerators	106	43
Freezers	38	16

(1) Achievable conservation potential under the 1989 final high load forecast.

Table 3-7 Conservation Resource Supply for Residential Sector Programs Under High Conservation Alternative

Program (Sector/Sub-sector)	Total Supply by 2010 (aMW) (1)	BPA Supply by 2010 (aMW) (1)
Existing Single Family Weatherization	102	62
Existing Multi-Family Weatherization	36	9
New Single-Family MCS	260	144
New Multi-Family MCS	37	12
Water Heaters	345	152
Refrigerators	343	115
Freezers	105	45
Other Appliances (2)	700	270

(1) Achievable conservation potential under the 1989 final high load forecast.
(2) For the High Conservation Alternative, this sector (sub-sector) includes administrative costs, in 1988 constant dollars, associated with acquisition of conservation alternatives.

Cost

The projected costs for BPA's residential conservation programs for all alternatives analyzed in this eis except the High Conservation Alternative are contained in Table 3-8. Projected costs under the High Conservation Alternative are contained in Table 3-9.

Table 3-8 Conservation Resource Cost for Residential Sector Programs

Program (Sector/Sub-sector)	Cost per MW (1) (1988$)(000)
Existing Single Family Weatherization	$6,842
Existing Multi-Family Weatherization	$6,750
New Single-Family MCS (2)	$7,826
New Multi-Family MCS (2)	$7,127
Water Heaters	$1,523
Refrigerators	$1,682
Freezers	$2,040

(1) Includes a 7.5 percent transmission line loss credit. Cost per-unit includes administrative costs, in 1988 constant dollars, associated with acquisition of conservation resources.
(2) These measures are expected to have a 70-year life. Compared to a typical life of 20 years for the other measures.

Table 3-9 Conservation Resource Cost for Residential Sector Programs Under High Conservation Alternative

Program (Sector/Sub-sector)	Cost per MW (1) (1988$)(000)
Existing Single Family Weatherization	$6,842
Existing Multi-Family Weatherization	$6,750
New Single-Family MCS	$7,826
New Multi-Family MCS	$7,127
Water Heaters	$1,523
Refrigerators (2)	$5,732

Freezers	$1,498
Other Appliances (3)	$3,138

(1) Includes a 7.5 percent transmission line loss credit. Cost per unit includes administrative costs, in 1988 constant dollars, associated with acquisition of conservation resources.
(2) New savings from refrigerators are assumed to come from the more expensive advanced technologies.
(3) For the High Conservation Alternative, this sector (sub-sector) includes additional achievable potential beyond that estimated for the other RPeis alternatives.

3.1.3 Industrial Sector Conservation Resources

Program Description

Conservation in industrial applications consists of increasing the efficiency of the energy used for a process, system, or specific application of an energy conservation measure (ECM) or electro-technology. Energy-consuming end uses within industrial facilities include motors, pumps, heating-cooling, fluid handling, ventilation, lighting, space and material heating, and controls. The ECM

application could be as simple as installing a single heat exchanger in a cooling line, or as complex as a complete upgrade and change-out of an entire material-handling application where motors, pumps, friction pads, guides, and controls are redesigned.

The industrial sector conservation resource consists of 12 major categories of manufacture, based on the Standard Industrial Classification (SIC) Manual listings and BPA's listing of the 100 largest industrial electricity users served by public utilities in the region (see Appendix C, Tables C-3 and C-4).

Energy Conservation Measures

Within the industrial sector, there are currently 15 major energy conservation measures that are recognized as most useful. They are described below.

High-Efficiency Motors Used to replace burned-out motors or to upgrade existing standard motors and are designed to minimize energy losses through better construction techniques and the use of improved materials.

Adjustable Speed/Variable Frequency Drives (ASD/VFD) Used to control the speed of a motor so that it is tailored to the load the motor is driving, thus doing away with the need for regulating devices such as gear reducers, belt and pulley systems, dampers, valves, flow regulators, etc.

Energy Efficient Motor Rewind Used to repair a failed motor by taking it apart and rebuilding it. Bearings, wiring, and insulation may be replaced.

Heat Recovery Equipment Used to recover heat (or cold) from a liquid or gas medium and supply that thermal energy to existing internal processes that previously used electricity or another fuel as a heat source.

Thermal Storage Used to store heat and cold from an existing source for use in an existing internal process.

Insulation Used to recover heat or cold loss in a process (excludes asbestos products).

Process Heat Changes Substitution for gas in an existing system or making efficiency improvements to existing boilers and boiler heat distribution systems.

Compressed Air Systems Efficiency improvements, such as humidity controls, compressor change-outs, improved controls/sequencing, and installation unloaders are applied to existing compressed air systems.

Lighting Used to replace or upgrade existing indoor lighting technology.

Energy Management Systems Used to reduce the run time of a given system by optimizing fluid flows, material handling, and controlled variables such as temperatures, pressures, and sequencing.

Material Handling Upgrades to material handling systems are limited to motor change-outs and upgrades, mechanical conveyors to replace pneumatic conveyors, ASDs, and energy management systems.

Power Factor Improvement Use of shunt capacitors on the utility system or inside an industrial facility.

Cooling Tower Conversion Use of a combination of heat and mass transfer to cool water (i.e., conversion cooling tower from counterflow crossflow).

Customer System Efficiency Improvements These general transmission improvements include transformer replacement, conductor replacement, and insulator addition and replacement.

Materials Handling; slurry Installation of water thickeners for the purpose of improved pump efficiency within a contained slurry-type materials handling system.

Furnace Upgrading The replacement and upgrading of coreless induction furnaces as permitted under currently held operating permits.

Operating Characteristics and Capacity Contribution

Industrial facilities in the Pacific Northwest, especially the large aluminum and pulp and paper plants, tend to operate constantly throughout the day, therefore yielding flat electricity consumption patterns. Typically, these plants also operate constantly throughout the year. Conservation programs in the industrial sector generally improve the efficiency of the operating equipment and reduce electricity consumption evenly across all hours of operation, which includes the time of system peak demand. The peak savings achieved through industrial programs is assumed to be proportional to the energy savings.

Environmental Effects and Mitigation

Most of the measures discussed above do not alter the current mechanical processes in a way that affects the immediate quality of any waste streams. Therefore, they impose little or no foreseen environmental impacts. Due to the diverse nature of the industrial sector, new energy conservation measures may be developed which could have impacts that may alter an existing waste stream or introduce a new waste stream.

BPA recognizes the environmental concerns and future needs relative to industrial energy impacts. However, in most applications, no negative impact would be realized because the action would take place under a highly regulated structure of Federal, state, and local laws and regulations. The ECMs, in many cases, have a positive impact by reducing the need for new generation or enhancing the efficiency of the process, which can result in reduced emissions.

In most industrial applications, there is sufficient regulation to deal with the environmental impacts that would be associated with the industry base located in the BPA service area. Tables 3-10 and 3-11 list the major regulating agencies in BPA's service territory and their jurisdictions.

Table 3-10 Environmental Regulatory Agencies in BPA's Service Territory

United States Environmental Protection Agency	EPA
Idaho Department of Health and Welfare	IDHW
Montana Department of Health and Environmental Sciences	MDHES
National Institute for Occupational Safety and Health	NIOSH
Mine Safety and Health Administration	MSHA
Oregon Department of Environmental Quality	ODEQ
Oregon Occupational Safety and Health Administration	OOSHA
Occupational Safety and Health Administration	OSHA

Washington Department of Labor and Industries	WDLI
Washington Department of Ecology	WDOE

Supply Forecast

The total regional supply of industrial conservation measures is projected to be 407 aMW (BPA's share would be 191 aMW) by 2010 under all alternatives except the High Conservation Alternative. Under the High Conservation Alternative, the total regional projected supply is 508 aMW.

Cost

The cost of BPA's industrial conservation program under all alternatives analyzed in this eis is $1,927 per megawatt. This cost includes a 7.5 percent transmission line loss credit. The cost per unit includes administrative costs, in 1988 constant dollars, associated with acquisition of conservation resources.

Table 3-11 Jurisdiction of Regulatory Agencies

	Idaho	Montana	Oregon	Washington
Air Emissions	IDHW	MDHES	ODEQ	WDOE
Discharges to Surface Water	EPA	MDHES	ODEQ	WDOE
Discharges to Ground Water	IDHW	EPA	ODEQ	WDOE
Hazardous Waste Management	IDHW	MDHES	ODEQ	WDOE
Mine Safety & Health	MSHA	MSHA	MSHA	WDOE
Occupational	OSHA,	OSHA,	OOSHA,	WDLI,

Health & Safety	NIOSH	NIOSH	NIOSH	NIOSH

3.1.4 Irrigation and Agricultural Conservation

Program Description

Energy efficiency improvements in the irrigated agriculture sector consist of measures that reduce or eliminate the electrical energy requirements for irrigating crops.

Energy Conservation Measures

Energy conservation measures include low-pressure sprinkler irrigation, drip irrigation, high-efficiency motors, nozzle replacement, well modifications and treatment, mainline upgrading, adjustable speed drive, pressure relief and bypass, low/high-angle discharge, and flow adjustment.

Operating Characteristics and Capacity Contribution

Conservation programs in the agricultural sector are directed toward reducing the electricity required in the pumping of water onto fields. The pattern of electricity use in this sector usually begins in the morning, continues fairly constantly throughout the day, then drops off in the evening, although some program efforts have attempted to promote watering later in the day. However, agricultural electricity use peaks in the spring and summer, versus winter for the system peak demand. Therefore, the energy saving results of conservation programs in this sector tend not to affect peak demand.

Environmental Effects and Mitigation

This sector of the conservation resource consists of several energy-related measures that are routinely practiced and considered environmentally benign. These measures have been addressed and researched to assess the local environmental impacts that might be associated with them. BPA-sponsored research projects such as the "Evaluation of Very Low Pressure Sprinkler Irrigation and Reservoir Tillage for Efficient Use of Water and Energy" (1988) suggest that the environmental impacts associated with most of the energy conservation measures result in a net positive environmental impact in that reductions in both energy and water consumption are realized and equipment life is extended. The primary negative impact results from a change in water droplet size from such measures as nozzle change-out, pressure adjustment, and angle discharge. In some cases, this change could increase the rate of soil erosion in a given area. However, through proper placement and equipment sizing, any change in soil erosion can be kept at a minimum and, in some cases, improved. In cases where efficient sprinkler

systems replace traditional flood and furrow irrigation, erosion is generally reduced. Table 3-12 lists the energy conservation measures implemented and their associated impacts.

Table 3-12 Irrigation Measures and Their Impacts

Measure	Effect	Potential Impact or Concern
Low-Pressure Sprinkler Irrigation	Droplet and spray change	Erosion
Drip Irrigation	Soil moisture concentration	Erosion
High-Efficiency Motors	Reduced energy consumption	No impact
Nozzle Replacement	Droplet size, decreased radius	Erosion
Well Modifications and Treatment	Increase pumping capacity	Land use
Mainline Upgrading	Improved distribution efficiency	No impact
Adjustable Speed Drive	Reduced energy, demand, water usage	No impact
Pressure Relief and Bypass	Reduced energy and -water usage	No impact
Low/High-Angle Discharge Flow Adjustment	Spray impact angle Water flow rated	Erosion Erosion

Supply Forecast

The total supply of irrigation and agricultural conservation is projected to be 35 aMW by 2010 under all alternatives analyzed in this eis (BPA's share would be 14 aMW). This is considered to be the total achievable conservation potential under the 1989 final high load forecast.

Costs

The cost of BPA's irrigation and agricultural conservation program is projected to be $1,648 per megawatt under all alternatives analyzed in this eis. This cost includes a 7.5 percent transmission line loss credit. The cost per unit includes administrative costs, in 1988 constant dollars, associated with acquisition of conservation resources.

13.2 Generating Resources

The availability of a resource at various costs is estimated in BPA's supply curves. This section contains the supply curve (cost and supply) projections for generating resources in the Pacific Northwest that are used in this eis analysis. They are not projections of what will be constructed, but rather, they are generic forecasts of the types and costs of resources that are assumed to be available for development. Information for each resource is organized by a description of the technology, its operating characteristics, costs, environmental effects and mitigation, and a supply forecast. Costs are given in 1988 dollars.

Transmission Cost Adjustment

All generating resources not directly applied to a load must be connected to transmission and distribution lines. This interconnection, as it is called, can be expensive, particularly if a resource addition is located far from transmission facilities or if local facilities are fully utilized. Transmission, or lack thereof, can affect the cost-effectiveness of a generating resource, so transmission costs are estimated for all generating resource types.

To make an accurate estimate of the transmission cost associated with integrating a particular resource, transmission planners need to know the capacity, location, and operating characteristics of that resource. Since this information is not available in sufficient detail at the planning level, a more general approach has been used here. For this analysis, a cost factor was added to each resource in a way that recognizes that resources far from load centers are more costly to integrate than resources near load centers. This approach to accounting for transmission cost also recognizes resources that can take advantage of surplus capacity in existing facilities.

For transmission cost estimating purposes, resources are divided into five location categories: resources sited west of the Cascade Mountains, resources east of the Cascades but within BPA's existing network, resources east of the BPA network, resources in Canada, and resources in California.

In the existing Northwest power system, the major load centers are located west of the Cascades and are centered around Seattle and Portland, the region's two largest population centers. The largest load growth is in the Seattle area. For this analysis, greatest load growth is assumed to continue west of the Cascades.

Transmission capital cost estimates were developed for each of the five location categories and converted to unit costs. Table 3-13 summarizes these cost estimates. These transmission capital cost adjustments are applied to generic resources. They are embedded in the total capital cost figures reported in this section. The transmission adjustment for the coal resources is based on the same methodology but was applied based on the prorated mileage relative to Colstrip, Montana. Operating and maintenance costs for additional transmission are not included in the transmission cost adjustment.

Table 3-13 Transmission Capital Cost Adjustments for Generation Resources (1988$)

Zone	Cost ($/kW)
West of Cascades	0
East of Cascades	120
East of BPA Network	410
California	0 (a)
Canada	0 (a)

(a) Resources from California and Canada are assumed to be system sales, which would compete with Northwest resources. Consequently, no transmission adjustment is applied to these resources.

3.2.1 Renewables

3.2.1.1 Conventional Hydropower

Technical Description

Water power is one of the oldest, simplest forms of energy. In its modern form, the potential energy of water is released as it drops through a turbine to generate electricity. Water is piped to the turbine through a "penstock," starting at the "forebay" or entrance to the penstock. Available energy is proportional to the elevation difference between the forebay and the turbine blades. This height is often referred to as feet of "head."

Hydroelectric projects can have large dams associated with them to store water and create head, or they may be "run-of-river" plants, which use a smaller dam (or diversion) to take a portion of a river's flow-out at a high elevation, drop it through a penstock and turbine, and release it at a lower level. The large majority of the potential projects are small run-of-river designs.

Long-range planning is based on the firm energy capability of the hydro system. The firm hydro energy capability is the amount of power produced by these regional hydro resources in the worst low-water period--called the critical period--recorded for the Columbia River Basin. The energy produced by the region's hydro projects during the critical period is calculated using the generation average for the period September 1928 through February 1932. The regional hydro system generates approximately 12,400 aMW of firm energy under critical water conditions.

Nonfirm Resources

Resource planning uses critical water flows to compute the region's and the Federal system's firm hydro energy. The regional hydro system, however, has historically experienced precipitation levels that produce greater than critical period flows. This excess water is used to produce nonfirm energy.

Planning does not include nonfirm energy in the loads and resources balance. Nonfirm energy increases regional resources by about 3,800 aMW annually when averaged over 50 years of historical water flows. The Federal share of this nonfirm energy is about 2,400 aMW based on 50 years of data. Nonfirm energy is even larger for both systems when based on 102 years of historical water flows.

Operating Characteristics and Capacity Contribution

The amount of water behind the dam, precipitation levels, loads in the service area, and PNW coordination affect the operation of hydro projects. Hydro projects provide both energy and peaking capabilities, which depend on the number of turbine units, streamflows, water storage, and the elevation of the dam.

Streamflow estimates are based on existing records of such information as the drainage areas above the site, precipitation records, and local ground water conditions. Hydrologic conditions vary greatly over the region and even within basins and sub-basins. In the west, winter storms produce immediate high flows, and in the east, flows are predominantly from melting snow in the spring. Hydro projects typically shave availability factors of 85 to 90 percent. Capacity factors of 50 percent are typical. (1)

Hydro projects have poor to excellent dispatchability and a widely varying match with natural load shape, especially seasonally. Hydro is generally good for capacity, but can vary widely depending on the natural streamflow shape' and restrictions on operational flexibility. Projects on streams without dependable summer flows make no contribution to firm summer capacity. Projects restricted to a constant discharge around the clock make only the same contribution to capacity as would a baseload plant.

Costs

The cost projections shown in Table 3-14 are either supplied by potential developers or calculated by an algorithm (Hydropower Analysis Model-HAM) contained within the Pacific Northwest Hydropower Data Base and Analysis System (NWHS). This algorithm uses individual developer estimates if they are available from permit and license applications. When consistent estimates are not available, the model develops a cost estimate from the physical characteristics contained in the application. All of the cost estimates are then aggregated into generic cost categories, i.e., Hydro-1, -2, -3, and -4.

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(1) 1986-1990 Generating Availability Report, North American Electric Reliability Council (NERC), August 1991, p. 118.

Table 3-14 Costs and Supply - Hydroelectric ($1988)

	Hydro-1	Hydro-2	Hydro-3	Hydro-4
Capital Cost ($/kW)				
eaST (a)	11.79	14.48	19.51	23.36
WEST (a)	10.59	13.28	18.31	22.16
O&M Cost				
Fixed ($/kW-yr)	21.00	27.00	37.00	44.00
Variable (mills/kWh)	0	0	0	0
Real Levelized Costs (mills/kWh)				
eaST (a)	21	27	36	42
WEST (a)	20	25	35	43
Nominal Levelized Costs (mills/kWh)				
eaST (a)	45	57	77	89
WEST (a)	43	53	75	91
REGIONAL SUPPLY (aMW)				
eaST (a)	45	57	77	89
WEST (a)	43	53	75	91
BPA SUPPLY (aMW)				
eaST	11	14	19	22
WEST	11	13	19	23

(a) The regional potential is split between the east and west side on a 60/40 ratio. The portion that is located on the east side receives a capital cost adder that reflects the transmission cost adjustment.

Environmental Effects and Mitigation

The impacts of hydroelectric development vary greatly from project to project. Impacts include effects on land use, wildlife, aesthetics, and impacts associated with construction (Figure 3-3). Although a single, small project may have only a small effect, it is necessary to consider the cumulative effects if a number of projects are developed on the same river or stream.

There are no emissions of greenhouse gases or particulates, and only small quantities of solid wastes are generated by hydroelectric plants. However, impoundment of a river or stream alters the surface water and habitat, and may block migration of fish. None of the potential projects considered for the region are located in the Northwest Power Planning Council's Protected Areas. This limits projects that might have irreversible impacts on anadromous fish populations.

Figure 3-3
Environmental Effects and Mitigation - Hydroelectric Power

Figure (Page E32 Environmental Effects and Mitigation - Hydroelectric Power)

A hydroelectric project that has an impoundment (the capability to store water) associated with it generally has a more severe impact than a run-of-river project. This is especially true for large impoundments (greater than 100 acres). Most of the sites in the data base used to develop the potential for the region are smaller run-of-river projects with no, or limited, impoundments.

Hydroelectric plants with greater than 30 MW of capacity may be either run-of-river dams or storage reservoirs, and are usually located on mainstream rivers or major tributaries. Projects of less than 30 MW capacity are typically located on small tributary streams. Often, the smaller streams have a higher gradient and provide sufficient head to operate turbines without the need for a large reservoir.

Protection of critical fish and wildlife habitat is accomplished via the Protected Areas amendments to the Northwest Power Planning Council's Fish and Wildlife Program and Power Plan. Among other environmental safeguards, these amendments state that, "...because Protected Areas represent the region's most valuable fish and wildlife habitat, hydropower development should not be allowed in Protected Areas, but should be focused in other river reaches." (See Chapter 2, Section 2.2.7.)

Supply Forecast

The procedure to generate regional estimates of supply uses the cooperatively developed Pacific Northwest Hydropower Supply (NWHS) Model. The model uses data from the NWHS model on cost, capacity, and output, combined with regional environmental information from the Northwest Environmental Data Base. The procedure used to develop estimates of potential hydropower resource capability for this eis involves several steps:

1. Sites that are located in the Northwest Power Planning Council's Protected Areas were screened out.
2. Even projects passing this screen could have environmental problems that may preclude development. In addition, the technical characteristics of many of these sites have not been fully explored, leading to the possibility that development may not be feasible for engineering, environmental, or economic reasons. To account for these factors, probabilities of completion were assigned, based on the stage at which the project stands in the regulatory process (permit pending to license granted), the layout of the project (diversion to canal), the status of the waterway structure (undeveloped to existing), and the value of the environmental resources at the site which would be impacted by development.
3. These probabilities (ranging from 20 to 95 percent) were applied to the capacity and energy potential of each project to obtain its probable contribution. The probable contributions of individual projects were then summed to obtain the regional potential.

This method produces a statistical estimate of the expected developable hydropower without the need to determine if specific individual projects should be developed--a determination that would be inappropriate, given the limited information available on a specific project and stream reach. Table 3-14 summarizes the results of this regional projection of supply.

It is important to remember that, even though a specific project is included in the estimate of potential, this does not mean the site will or will not be developed.

This methodology is intended to provide a macro assessment of the potential in the area. The presence or absence of a specific project has a minor effect on the overall projection for the small hydro resource.

3.2.1.2 Geothermal

Technical Description

Geothermal energy taps heat available within the earth's core. Heat, water, and permeable rock, found in combination, are the requirements for a hydrothermal resource for power generation. Generally, wherever tectonic plates abut, there is the potential for geothermal resources. Here, the earth's mantle is relatively thin and fault systems give way to earthquakes and volcanoes; magma from the earth's core protrudes close to the surface, bringing geothermal heat with it. High-temperature gradients found in drilling, in hot springs and geysers, and in certain kinds of geologic formations and geochemistry, provide evidence that hydrothermal systems exist beneath the earth's surface.

The biggest problem with developing geothermal resources is finding the resource. Drilling to depths of 10,000 feet or more may be required to locate a production well to bring geothermal steam or fluid to the surface, where it can be processed through a power plant. Prospecting for high-quality geothermal reservoirs is financially risky and expensive.

There are three principal types of geothermal conversion technologies used for power generation: (1) dry steam, (2) flash, and (3) binary cycle plants. In dry steam systems, the geothermal resource is a gas at temperatures in excess of 350 degrees F. High-pressure geothermal steam is drawn up through wells as a gas and goes directly through a turbine; then it condenses to a liquid to be injected back into the reservoir.

In flash systems, the geothermal resource is found as a pressurized liquid brine at temperatures greater than 350 degrees F. Because the resource is a fluid under high pressure, it must be "flashed" or depressurized to a gas state before it can be processed through a turbine. When geothermal fluid flashes, only a portion of the liquid becomes steam; the rest remains as a high-pressure liquid. Depending on the temperature and pressure of the brine as it leaves the well head, geothermal fluid may be flashed twice in sequence to maximize the "quality" or proportion of steam possible from the fluid.

Binary systems extract heat from geothermal fluids that have relatively low temperatures, less than 300 degrees F. A binary system must use another working fluid besides the geothermal brine (such as butane, iso-butane, or pentane) that has a low boiling point compared to water. In a binary system, there is the geothermal loop, a working fluid loop, and a cooling loop. All three are separate and do not mix. The geothermal loop imparts heat to the working fluid in an evaporator, where the working fluid boils to a gas. The hot gas expands through a turbine generator. Finally, the cooling loop runs through a heat exchanger and condenses the working fluid. Binary systems have used geothermal resources with temperatures as low as 177 degrees F.

The temperature and pressure of the resource dictate the choice of technology employed at a particular geothermal site. All geothermal technologies are mature, and geothermal energy is used worldwide. Active geothermal regions in the U.S. include The Geysers, with about 2,000 MW on-line, and the Imperial Valley and Glass Mountain in California, as well as the Basin and Range geologic province covering parts of Utah, Nevada, and Idaho.

Typically, geothermal plants are sited in 20 to 50 MW units, but modular systems as small as 5 MW have been developed. One advantage of small-scale modular units is that they can be used to help evaluate a reservoirs characteristics while generating power.

Operating Characteristics and Capacity Contribution

Geothermal power is generally operated as a baseload energy source. These projects typically have availability factors of 85 to 90 percent and capacity factors of 70 to 75 percent. Geothermal power is generally considered to be baseloaded because, due to constraints of well dynamics, these resources are generally not amenable to rapid fluctuations in output. However, In some cases, such as some units at The Geysers, units can be operated to follow load.

Because geothermal resources are usually operated as baseload plants, they provide roughly the same contribution to capacity as any other baseload plant (e.g., comparable to coal plants). To the extent that they are more reliable and that outages can be planned, they would be slightly better.

Costs

In this eis, the cost data for the geothermal resource is derived from the Northwest Power Planning Council's Staff Issues Paper 89-36, Geothermal Resources. This data reflects a range of geothermal conversion technologies at sites with defined geothermal resources. Costs would be expected to vary depending on site-specific conditions. Table 3-16 shows costs for two categories of geothermal energy. GEO-1 represents a pilot plant (10 to 30 MW) in the high Cascades. GEO-2 represents the potential in the Basin and Range geologic province. Basin and Range development has already occurred and future development in this area has less uncertainty associated with it than does the Cascade resource.

Table 3-16 Costs and Supply - Geothermal (1988$)

	GEO-1	GEO-2
Capital Cost ($/kW)	27.85	29.20
O&M Cost		
Fixed ($/kW-yr)	102.00	95.00
Variable (mills/kWh)	2.7	1.4
Real Levelized Costs (mills/kWh)	74	42

Nominal Levelized Costs (mills/kWh)	148	84
Supply (aMW)		
Region	27	390
BPA	27	390

Environmental Effects and Mitigation

Depending on the kind of conversion technology and the size of the facility, geothermal resource development can have environmental impacts (Figure 3-4). Environmental impacts are described for binary, flash, or dry steam systems. The impacts from all three types are similar, and the flash system is the most likely to be used. (See Table 3-17.) Plant size, siting, and operation and maintenance practices also affect the magnitudes and kinds of impacts that may be expected. Many of these impacts, however, can be mitigated, and geothermal energy can provide a reliable, relatively clean generation alternative.

Geothermal energy conversion requires processing large quantities of fluids and gases. Dry steam systems, and flash steam systems to some extent, introduce non-condensable gases into the environment, particularly hydrogen sulfide (H_2S). In small concentrations, H_2S has an unpleasant, rotten egg odor. In large

concentrations, the gas paralyzes the olfactory nerves and becomes undetectable; it is lethal at high concentrations. H_2S can accumulate in low pockets and threaten plant species and wildlife. Carbon dioxide, another non-condensable gas, is also discharged into the atmosphere in significant amounts. But the concentration of CO_2 is about one-thirtieth that emitted by a coal plant per kilowatt-hour (kWh). Other contaminants from geothermal steam pose less serious hazards compared to hydrogen sulfide. In dry steam, there are small concentrations of boron, arsenic, and mercury.

Waste heat in the form of condensing steam from turbines poses another environmental concern. Large quantities of waste heat are dumped into the environment, mainly from cooling towers. Clouds of condensing steam from the towers may affect local climates, producing fog and causing a visibility hazard, especially on roads. Large quantities of cooling water are needed to operate the cooling system. Condensed steam can be used as a coolant, augmented by some additional water supply. Water needs for power generation, particularly in arid areas, may conflict with local agriculture, mining, or public consumption uses.

Figure 3-4
Environmental Effects and Mitigation - Geothermal

Figure (Page E38 Environmental Effects and Mitigation - Geothermal)

Water quality can be affected at a geothermal site. Brine coming to the surface from supply wells and returning through injection wells has the potential to contaminate local water tables. Most geothermal fluids are highly saline and contain trace toxic elements such as boron, mercury, lead, ammonia, and arsenic. Manganese and iron, which make water acidic, may also be found. Also, there is the potential for leakage into shallow aquifers or accidental release of brine into streams or lakes.

Waste products pose problems unique to geothermal energy. Primary among these are hazardous wastes from drilling; emission of hydrogen sulfide, and concentrated scaling from brine residue. Containment, processing, and removal of these chemicals pose risks in transportation and handling.

Another concern in geothermal operations is the maintenance of the geothermal reservoir. Normally, re-injection of the brine is practiced to help recharge fluids into the reservoir and prevent subsidence of the well field. However, injection may induce seismic activity, due to high local pressures generated by the re-entering fluid.

Like any major construction activity, the development of geothermal sites can have a major impact on local communities. There is heavy road use, erosion, disruption of local ecosystems, and noise. Some of these effects are transitory, while others are ongoing during plant operations. Energy production may require only about 20 to 100 acres for a 50-MW plant, but the exploration, drilling, construction, and operation facilities may encompass from 500 to 3,000 acres.

There are also social and economic effects of geothermal development. Rapid, intense development and the accompanying influx of new residents can tax a community's ability to provide schools, housing, and other essential services. Finally, aesthetics are a major concern. The visual impact of a well field and power plant facilities may-be objectionable, especially in pristine areas such as the Cascades, where many potential geothermal sites exist.

By far the most pronounced environmental impact from dry steam and flashed steam plants is the emission of hydrogen sulfide. Mitigation measures include abatement using the Stretford process, which traps nearly 99 percent of the non-condensable H2S emissions, reducing the compound to elemental sulfur and hydrogen. Other control methods include a hydrogen peroxide/iron catalyst process, which removes 90 to 98 percent of the hydrogen sulfide left in steam condensate. Control of well head ventilation and burning vent gas can also reduce H2S. In binary power systems, H2S emissions are not a problem, since the geothermal fluid remains bin a closed loop.

Several mitigating measures can be taken to minimize the impacts of geothermal power production. Dry cooling towers reuse the geothermal steam as a cooling water source after it condenses, offering an alternative to the use of additional water for cooling. However, dry towers are large and expensive. Slant drilling to locate several wells from one pad reduces land impacts. Loud noise caused by steam release at wells can be muffled to avoid hearing injury to field workers. Risks associated with hazardous wastes can be minimized by employing good safety practices and accident prevention measures in transportation and handling. Some wastes can also be incinerated and rendered harmless.

In general, geothermal steam or brine chemistry, the conversion technology used, and the characteristics of the geothermal reservoir dictate the primary environmental concerns associated with a particular plant. Each site poses its own peculiar environmental problems, which must be dealt with on a site-specific basis.

Examples of potential environmental impacts from geothermal generation are shown in Table 3-17.

Table 3-17 Potential Annual Routine Environmental Impacts Per Average Megawatt of Energy Generation of Flash Geothermal Plants (a)

Potential Impacts	Generation
Air Pollutants	
Hydrogen Sulfide (tons)	0.09 to 0.88
Ammonia (tons)	3.3 to 339.99
Methane (tons)	2.16 to 90.39
Carbon Dioxide (tons)	700.8 (b)
Arsenic (tons)	0.0075 to 0.09
Boron (tons)	0.225 to 2.28
Mercury (tons)	0 to .045

Benzene (tons)	0.43
Radon (curies)	0.21 to 32
Water Quality Impacts	
Consumption (acre-ft)	44.8
Thermal Discharge (MMBtu) (c)	131,000
Land Effects (d)	
Acreage Requirements	0.27 per MW capacity corrected for capacity factor (does not account for exploration)
Waste Streams (tons)	
Drilling Mud (cubic ft)	3622 to 7839.75
Solids Separated from Fluids	86
Solids from Hydrogen Sulfide Abatement	3.52
Solids from Scale Removal	4.62
Employment (d)	
construction (employee-years per MW capacity)	4.1
operations (employees per MW capacity)	0.3
Occupational Safety and Health per MW capacity	
O&M Injuries	0.008

(a) Unless otherwise indicated, these generic estimates are adapted from: U.S. DOE. 1983. Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors. DOE/EP-0093. Washington, DC.
Specific pollutants are very dependent on the chemistry of specific geothermal resources.
(b) Source: Fluor Daniel, Inc. Environmental Data for Thermal Resources, Prepared for BPA 1991.
(c) Thermal discharge may be to air, water, or reinjection to the ground.
(d) See sources and calculations in Appendix F to this eis. Seventy-five percent capacity factor assumed.

Supply Forecast

The technology of geothermal energy is well established and demonstrated. It can, however, only be applied where a recoverable geothermal heat source exists. The only demonstrated use of geothermal energy in the Northwest is a now-defunct binary cycle demonstration plant at Raft River, Idaho.

The most likely locations in the Northwest for geothermal development are the Basin and Range province (southeastern Oregon and southern Idaho) and the high Cascades of southern Oregon. Although the high Cascades area offers the greatest potential (1,00+ aMW), it is also the most uncertain. The GEO-1 resource listed in Table 3-16 represents a 30-aMW high Cascades pilot project. GEO-2

represents 390 aMW of potential Basin and Range development. It is hoped that the high Cascades pilot project will lead to more exploration and subsequent development of the area. However, the uncertainty of the resource precludes projecting a larger supply at this time.

3.2.1.3 Wind

Technical Description

Wind turbines convert the kinetic energy of wind into electrical energy by transferring the momentum of air to the rotation of wind turbine blades or a shaft connected to a generator. There are numerous wind turbine designs and design variations, but the most common is the horizontal axis turbine, which has the axis of blade rotation oriented parallel to the ground (the blades resemble an airplane propeller). Gears step up the blade shaft rotation to a rate nearly matching the 1,800 revolutions per minute (rpm) needed to synchronize the generator, which is connected through a switchgear to a utility grid. In the horizontal axis design, the rotor blades, turbine, gears, and generator are all mounted on a bedplate or platform set atop a tower and contained within a housing as a single unit.

Engineers have devised two principal means to regulate blade speed for controlling power output: variable pitch and stall regulation. With variable pitch, a wind machine's blades adjust so that the turbine begins generating at a cut-in speed, then rises to a rated power output, and finally, holds this level until the wind reaches a cut-out speed. With stall regulation, blades are aerodynamically designed to progressively lose their lift above a certain rotation speed. Turbine housings are also designed with passive or active yaw control to rotate on a vertical axis and align the turbine in the direction of the wind.

The power available in a wind stream is proportional to the cube of the wind velocity; as the wind speed doubles, output available increases by a factor of eight. Due to wind-to-mechanical-shaft conversion inefficiencies, output from a wind turbine varies as the square of the wind speed; i.e., as the wind speed doubles, output increases four times. Because the amount of energy extracted from wind is extremely sensitive to wind speed, optimum siting of individual turbine units requires a substantial amount of data describing how wind speeds are distributed over the site, as well as over time. There is even significant variation of wind strength as tower height varies above ground. Winds aloft tend to be more stable and stronger than those near the ground. Potential sites must have average annual wind speeds in excess of 12 miles per hour at 33 feet above the ground to be considered worth developing.

Wind machines are generally grouped together into arrays at a site, called a wind farm or wind park. A typical arrangement is to place turbine units in rows about 10 rotor diameters apart downwind, with adjacent crosswind turbines within the rows about 3 to 5 rotor diameters apart--although optimum siting must take terrain and the interactive effects among turbines into account. Wake disturbance and turbulence from one wind machine can severely limit the energy extracting potential of other machines downwind. Array losses due to energy extraction by upwind turbines can drop energy production as much as 15 to 20 percent in poorly sited wind parks.

Wind power technology has undergone substantial development since the early 1980s, and the technology has now reached the status of a mature industry. In California today, there are about 17,000 wind turbines operating with an installed capacity of 1,500 MW at 3 principal sites. (This is about 90 to 95 percent of the installed wind turbine capacity in the world.) California has been a proving ground for the developing wind industry. Initial problems with fatigue failures and reliability are now being addressed with better aerodynamic and structural designs and improved controls.

Operating Characteristics and Capacity Contribution

Wind power depends on the availability of wind. Despite wind's unpredictability, this renewable resource does exhibit certain patterns. Sites in the Columbia Gorge, for example, where winds are topographically and thermally induced, attain maximum availability in the spring and summer, when cooler air on the west side of the Cascades moves eastward to displace rising warmer air inland. At other sites, such as those along the southern Oregon coast and at the foot of the Rocky Mountains in Montana, winds are driven by storms, which tend to occur in winter.

Although wind cannot be counted on to meet peak loads, it can displace some energy loads. Turbine units with good mechanical design and regular maintenance have shown availability factors up to 92 to 93 percent, but they vary widely in output. Typical capacity factors for on-line units can vary widely from 10 to 35 percent, depending on the annual average wind speed and the persistence of energy-producing winds. Wind machines being installed today tend to be 100 to 300 kW units, which are lighter in weight and more efficient than their predecessors. Because of their low operating (marginal) costs, wind units are not generally operated as a dispatchable resource; instead, wind energy is used whenever it is available. Wind generation located in areas with unpredictable, gusty wind can place extra capacity demands on electrical systems, whereas wind generation in areas of regular, predominantly daytime winds (as in the interior valleys of California) are more neutral.

Costs

The cost of electricity from a wind facility is a function of the wind conversion technology cost, as well as the wind resource present at the site. The costs shown in Table 3-18 assume a capacity factor of 25 percent. Wind-1 is a compilation of those sites considered more available and accessible than those in Wind-2.

Table 3-l8 Costs and Supply - Wind (1988$)

	WIND-1	WIND-2
Capital Cost ($/kW)	11.58	12.50
O&M Costs		
Fixed ($/kW-yr)	15.00	16.00
Variable (mills/kWh)	11.0	11.5
Real Levelized Coats (mills/kWh)	53	53
Nominal Levelized Costs (mills/kWh)	81	81
Supply (aMW)		
Region	261	1,241
BPA	65	310

Environmental Effects and Mitigation

Although wind energy is environmentally benign, there are some distinct environmental impacts in siting wind turbines (Figure 3-5). Wind parks of any sizable megawatt capacity require the development of large tracts of land. Only a

small portion of the land would be directly occupied by turbines, roads, transmission lines, substations, and buildings. The remaining land in and around turbines could be used for livestock grazing or other non-intensive farming. Some of the best sites are in the most scenic areas along the Pacific coast and in the Columbia Gorge, where aesthetics may be an environmental concern.

Furthermore, wind turbines do generate audible noise, which can be objectionable to nearby residents, and electromagnetic "noise," which can interfere with television reception. A unique potential effect is "blade flash." At certain times of the year sun may "flash" off the rotating blades, causing visual irritation to viewers.

Figure (Page E43 Environmental Effects and Mitigation - Wind)

Figure 3-5
Environmental Effects and Mitigation - Wind

Some wind sites may pose a hazard to both birds and aircraft. Some sites may be in the path of migratory birds. Secondary impacts would be caused by constructing transmission lines to bring electricity from wind sites to transmission grid connection points. By and large, siting impacts can be mitigated with good planning.

Examples of potential environmental impacts from wind generation are shown in Table 3-19.

Supply Forecast

In 1985, BPA completed a 5-year resource assessment of over 300 wind data sites in the Pacific Northwest. Of these, 39 areas were identified to have potential for future commercial development. BPA continues to gather data at five of these sites for long-term analysis. The Northwest Power Planning Council used this data, as well as technology data from California, to project regional supply.

Approximately 1,500 aMW is projected as developable in the Northwest. This potential is dispersed among many areas. The largest potential is on the Blackfoot Indian Reservation surrounding Browning, Montana. This potential (approximately 3,000 MW peak, 1,000 aMW energy) is not currently considered available due to the remote location and difficulties in getting power to load centers. Preliminary evaluation of transmission constraints and cost has been completed. According to a PNUCC Study (Blackfeet Area Wind Integration Study-PNUCC, August 1991.) approximately $1 billion and 10 years would be required to complete environmental studies, procure rights-of-way, and design and construct the lines needed to integrate 3,000 MW of wind resource capacity.

Table 3-19 Potential Annual Routine Environmental Impacts Per Average Megawatt of Wind Generation

Potential Impacts	Generation
Air Pollutants	Potential electromagnetic interference and noise emissions
Water Quality Impacts	No direct impacts
Land Effects (a)	
Acreage Requirements (land occupied by facilities or partially obstructed by guywires)	23.6 per MW capacity/corrected for capacity factor
Waste Streams	No annual residue except office and maintenance wastes (b)
Employment (a)	
Construction (employee-years per MW capacity)	1.9
Operations (employees per MW capacity)	0.4
Occupational Safety and Health per MW capacity (b)	
O&M Injuries	35 x 10^(-6) to 69 x 10^(-6)
O&M Deaths	0 to 27 x 10^(-7)
Construction Injuries	8 x 10^(-5) to 149 x 10^(-6)
Construction Deaths	1 x 10**(-7) to 3 x 10**(-7)

(a) See sources and calculations in Appendix F to this eis. Twenty-five percent capacity factor assumed.

(b) Adapted from Arthur D. Little. 1985. Analysis of Routine Occupational Risks Associated with Selected Electrical Energy Systems. ea-4020. Electric Power Research Institute, Palo Alto, California.

3.2.1.4 Solar

Technical Description

Solar Thermal. Solar thermal plants are similar to other thermal generating plants--they convert heat energy into electricity through a turbine generator. Solar energy is highly variable, both during the day and between seasons. It is not available at night, and is greatly diminished during cloudy weather. Because solar radiation is diffuse, it must be gathered and concentrated to be useful in a solar thermal system. This requires large arrays of panels with controls, and mechanisms to reflect and focus the incident light and direct it to a heating unit. The heating unit

of a solar thermal station has high absorptivity for trapping and retaining incident radiation, which is then transferred to a working fluid.

Collectors for solar thermal generators are characterized by large surface areas for capturing sunlight, and specific geometric shapes for concentrating the radiant energy. There are three main types of collectors: central station receivers, line-focus parabolic troughs, and point-focus parabolic dishes. In central station receivers, movable mirrors, called heliostats, track the sun and reflect the sun's energy to a central receiver mounted on a tower.

The best example of a central receiver station is the 1 0-MW plant in Barstow, California, which has operated since 1982. This system has 1,818 individual tracking heliostats with 766,000 square feet of reflective surface. In its operating history, the plant has produced as high as 11.7 MW of peak power, with a 10 percent capacity factor and a maximum annual output of 8,816 MWh.

Parabolic in-line troughs are the solar thermal power technology most used by utilities. The reflective trough is bent into a parabolic shape the entire length of the trough and concentrates the sun's energy along a line parallel to the parabolic trough. Along this line, receivers are tun to capture the concentrated energy.

Because many of these systems are designed to be stationary, elaborate tracking mechanisms and controls are not needed. Troughs are typically oriented north-to-south and lie horizontally. This configuration tends to offer the best tradeoff between maximizing capacity and keeping first costs and maintenance costs down. If energy is to be maximized instead of capacity, other orientations--such as tilting or tracking the troughs toward the sun--can be considered.

Receivers for in-line parabolic troughs are a specially coated pipe inside a glass vacuum tube. One company, Luz International--which operates the world's seven largest solar thermal plants--uses a synthetic oil as a heat transfer fluid in the pipes. The oil reaches 753 degrees F, then runs through a heat exchanger and super heats the steam that drives a turbine generator. With this design, solar thermal conversion efficiency has improved to about 29 percent.

Point-focus parabolic dish systems are single dish units, focusing the solar energy to a single point where the receiver is located, like a flashlight reflector in reverse. Unlike the in-line troughs, the parabolic reflector must track the sun continuously on two axis. One axis allows for tracking east to west during the day; the other axis allows for tracking north to south as the sun's declination angle changes with the seasons. Because of this system's requirement for accuracy and reliability to work effectively, fabrication is difficult and expensive.

Some point-focus systems have external heat engines, such as a reciprocating Stirling, that absorb heat directly and turn generators. Others have a system of fluid lines connecting each receiver and carrying a heat transfer fluid, which in turn is used in a turbine generator. Compared to the in-line parabolic reflectors, point-focus systems can concentrate much more energy. As of 1987, there were four point-focus reflector pilot projects testing various engine and generation technologies.

Photovoltaic. Photovoltaic cells (PVs) use the photoelectric effect to convert the sun's radiation directly into DC power. In photovoltaic cells, sunlight strikes a semiconductor material, typically a treated silicon, and frees up electrons, which generates a DC current. The DC power is then conditioned through an inverter with controls to produce AC current.

There are two main types of PV systems: flat-plate and concentrating. Flat-plate systems are usually deployed as a group of cells in stationary panels. Thus,

the incident sunlight upon the cells varies markedly throughout the day and with the season as the angle of the sun's rays changes. Concentrating systems, on the other hand, track the sun throughout the day and are outfitted with lenses to concentrate the sunlight.

Photovoltaic cells are usually grouped together into waterproof modules that range from 0.1 to 2 square meters. These modules are laid out side by side in banks to form arrays. A typical PV cell produces less than 2 amperes at about 0.6 volts, or about 1.2 watts of energy. Commercial PV flat-plate cells can achieve about 12 percent efficiency in converting sunlight into electrical energy; concentrating systems have reached better than 26 percent efficiency using a single-crystal silicon material. Multiple thin-film layered cells currently under development can theoretically reach 42 percent efficiency.

Although the costs of producing PVs are coming down and efficiencies are going up, the technology is still very expensive. Single-layer thin film cells, the least costly to manufacture, also have very low conversion efficiency, about 4 to 6 percent. For this technology to reach wide market acceptance, analysts estimate that efficiencies would have to reach a threshold conversion level of 15 percent; laboratory versions have reached 12 percent. As more and more PVs are manufactured--there were only 30 MW produced in 1988--the industry will be able to reduce costs even further. Costs are expected to drop from a current 55 cents per kWh, down to 8 cents per kWh by 2010.

Photovoltaics are a proven technology with many applications currently in use, including calculators, range fences, and remote lighting and signaling stations. Flat-plate PVs have a free energy source, low operating and maintenance costs, minimal environmental impacts, and very high reliability. Concentrating PVs have a lower reliability because they are more complex mechanically and therefore subject to failure.

Operating Characteristics and Capacity Contribution

Solar Thermal. A solar thermal system's capacity is dependent on the sun. Solar insolation has a daily peak in early afternoon, and, of course, is not available at night. There is also seasonal variation due to the change in the sun's declination angle. Any transient cloud cover also affects the amount of energy available from the sun.

Luz's systems use natural gas as a back-up fuel to boost peak or maintain capacity during cloudy periods and late in the day. in Luz's California plants, the proportion of energy contributed by gas in a solar energy system is constrained to no more than 25 percent. If solar thermal plants were used to supply capacity, as Luz's California plants are, the situation would be analogous to gas-fired systems backing up nonfirm hydro in the Pacific Northwest. A fossil fuel used as a back-up presents the question of whether this fuel would be better used in another application, such as space heating. Without a fuel back-up, a solar thermal station's capacity factor is diminished significantly.

For eight of Luz's solar Electric Generating Stations, typical capacity factors range from 25 percent for a 13.8-MW plant, to 36 percent for an 80-MW plant. First costs range from $4,500 to $2,788 per kW for these same plants. There are about 6,000 to 8,000 square meters of collector area per MW of capacity. Luz's has an installed capacity of over 160 MW at six sites, with almost another 500 MW planned. Luz plants operate in latitudes and climates where the available insolation is much higher than that available in the Pacific Northwest. The most promising locale for solar generating plants in this region is east of the Cascades.

Solar thermal systems offer little or no dispatchability but provide a very good match with natural load shape, especially in summer. Natural gas burning can extend generation into the evening hours after sun sets. Solar thermal systems otter a very good contribution to summer capacity, and a good contribution to winter capacity.

Photovoltaics. As with solar thermal, a PV system's capacity is dependent on the sun. Solar insolation has a daily peak in early afternoon, and, of course, is not available at night. There is also seasonal variation due to the change in the sun's declination angle. Any transient cloud cover also affects the amount of energy available from the sun.

Solar radiation is very dispersed and varies significantly with latitude and climate. The average daily total solar radiation in Phoenix is about twice that of Seattle. Consequently, the most promising PV sites in the region are east of the Cascades. Although about 1 kW of-solar radiation, called insolation, falls on a square meter at noon on a sunny day, a typical PV array can generate only about 120 watts per square meter. A 50-MW power installation would require about 90 acres of PV cells. This is peak capacity and does not account for diminished performance under cloudy skies or early or late in the day. PV system capacity factors for future concentrating PV plants may reach as high as 33 percent.

Photovoltaic systems offer little to no dispatchability, but provide a good match with natural load shape, especially in summer. PV systems offer a good contribution to both summer and winter capacity.

Costs

The cost estimates in Table 3-20 cover three configurations of solar thermal facilities. The solar facility with combustion turbine back-up is characteristic of the more successful California installations. The natural gas-fueled back-up tends to lower the overall cost of the facility and provides a more dependable resource.

The cost of photovoltaic cells is currently on the order of $5,000 per peak kilowatt.

Cost reductions are projected to bring cost of installed photovoltaic systems down to $4,000 per kW. Although specific Northwest applications are possible, it is likely that solar thermal systems will remain more competitive for the foreseeable future.

Table 3-20 Costs and Supply - Solar

	Sol-TR (a)	Sol-TRHTR (a)	Sol-CT (a)
Capital Cost ($/kW)	3,009	3,099	2,485
O&M Cost			
Fixed ($/kW-yr)	44.00	44.00	6.00
Variable (mills/kWh)	0.8	0.8	0.8
Real Levelized Costs (mills/kWh)	109	111	78
Nominal Levelized Costs (mills/kWh)	193	196	138
Supply (aMW)			
Region	22	22	42
SPA	22	22	42

(a) Sol-TR is a stand-alone parabolic trough system. Sol-TRHTR is a parabolic trough with gas heater. Sol-CT is a parabolic trough with a combustion tune backup.

Environmental Effects and Mitigation

Solar Thermal. Although the energy source for solar thermal systems is free and environmentally benign, plant siting and operations do have some environmental impacts. All turbine generators require some cooling to condense working fluids, whether the fluid be steam in central station systems, or butane, iso-butane, or pentane working fluid in a closed loop reciprocating engine. Dry cooling with air may be the heat sink of choice, but even this air must be conditioned, usually with a cooling tower or cooling pond. Ultimately, some makeup cooling water is required to cool the air. In hot, dry climates where solar thermal plants are most likely to be located, water for cooling comes at a premium.

Because of the diffuse nature of solar radiation, large sections of land are required for developing solar thermal sites, which has a localized effect on the ecology of land taken out of use.

If natural gas is used as a back-up energy source, then plant operators must reckon with the impacts of natural gas combustion. Lastly, the working fluids used in engines and turbine generators, such as oils, butane, iso-butane, or pentane must be managed and contained to prevent inadvertent escape into the environment.

Photovoltaic. Significant environmental impacts of PVs are in the industrial processing of the PV materials, where such chemicals as gallium arsenide and cadmium sulfide are used, and in the large surface areas of land required to set up a PV plant.

Examples of potential impacts from solar development are shown in Figure 3-6 and Table 3-21.

Figure (Page E49 Figure 3-6 Environmental Effects and Mitigation - Solar)

Table 3-21 Potential Routine Annual Environmental Impacts Per Average Megawatt of Energy Generation of Central Solar Thermal Generation (a)

Potential Impacts	Generation
Air Pollutants	None
Water Quality Impacts	
Consumption (acre-ft)	0.39 assuming that either central tower or heat exchange fluid other than water is used. (d)
Thermal Discharge (b) (MMBtu)	23,000

Land Effects (c)	
Acreage Requirements	6 per MW capacity corrected for capacity factor.
Waste Streams	No annual residue except office and maintenance wastes. (d)
Employment (c)	
Construction (employee- years per MW capacity)	19.6
Operations (employees per MW capacity)	0.4
Occupational Safety and Health per MW capacity (c)	
O&M Injuries	24 x 10E-6 to 28 x 10E-6
0&M Deaths	0 to 24 x 10E-7
Construction Injuries	342 x 10E-6 to 1428 x 10E-6
Construction Deaths	2 x 10E-7 to 28 x 10E-7

(a) These examples do not include impacts from natural gas-fired combustion that may be Used to firm solar-thermal generation.

(b) Thermal discharge may be to air or water.

(c) See sources and calculations in Appendix F to this eis. Fifty percent capacity factor assumed.

(d) Adapted from Arthur D. Little. 1985. Analysis of Routine Occupational Risks Associated with Selected Electrical Energy Systems. ea-4020. Electric Power Research Institute, Palo Alto, California

(e) U.S. DOE. 1983. Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors. DOE/EP-0093. Washington, DC.

Supply - Forecast

The best potential solar site in the Northwest is in southeastern Oregon. However, because of its latitude, southern Oregon receives only 70 percent of the solar energy received by the best sites in the Pacific Southwest. This, along with higher avoided cost in the Southwest, will be likely to inhibit development in the Northwest. Consequently, only a modest quantity of solar thermal is projected for the Northwest: 80 MW capacity (22 aMW) for both the parabolic trough (Sol-TR) and the parabolic trough with heater (Sol-TRHTR), and 150 MW capacity (42 aMW) for the parabolic trough with combustion turbine backup (Sol-CT) (Table 3-20).

3.2.2 Thermal

3.2.2.1 Cogeneration

Technical Description

Cogeneration is the sequential production of more than one form of energy output from one energy source. Cogeneration is particularly well-suited to process industries, such as pulp and paper, lumber, and food processing, Where large quantities of steam or heat are used for drying or to process materials and plant electric loads are high. Typically, high-pressure, high-temperature steam can be used first in an electricity generation process, then bled off from a turbine for process heat.

Cogeneration is not new. Before large central generating plants came into vogue in the 1930s, as much as 50 percent of the electricity generated in this country came from cogenerators. Historically, most cogeneration plants involved large (5 to 50 MW) units in industrial facilities. Today, cogeneration plants are as diverse as the industries and commercial applications where they are found, and the technology employed is as varied as the kinds of fuels used.

A variety of fuel types can be used in cogeneration. In wood industry plants, for example, wood waste must be disposed and is used as an energy source.

Fuels for proposed cogeneration projects nationwide are as follows: natural gas, 58 percent; coal, 19 percent; and biomass, waste, and other fuels accounting for the rest. Burning municipal solid waste at garbage sites, and using the methane produced at sewage treatment plants, are two possible applications for waste fuels.

Since the Public Utilities Regulatory Policy Act of 1978 (PURPA) has encouraged Independent power production, small, modular systems that can be fueled with natural gas have come into the market. These modules, rated from 4 to 20 MW, are suitable for hospitals, schools, prisons, hotels, and other small commercial and institutional establishments. Rather than the traditional boiler/turbine arrangement of larger cogeneration systems, these packaged units may employ reciprocating internal combustion engines. They are likely to use heat recovery of the exhaust gases to serve secondary energy needs--hot water, drying, space heating, refrigeration, or space cooling. Cooling applications use some of the heat recovery to drive absorption chillers.

Cogeneration technologies have reached commercial maturity and can be operated reliably with high availability and capacity factors. As electricity prices increase, a threshold is reached where it makes economic sense to operate a cogeneration plant. At mills where process heat, as well as electricity, is needed and wood residue is both a waste problem and a fuel opportunity, cogeneration can be an attractive solution. The option may not be as straightforward at a hospital or university. Fuel sources must be stable in both price and availability to induce potential cogenerators to opt for generating their own electricity.

Operating Characteristics and Capacity Contribution

Cogeneration is particularly suited to sites that have a relatively constant thermal load, which requires a stable fuel supply. For this reason, cogeneration makes a good baseload technology. Cogeneration projects have high availability factors of 85 to 90 percent.

Generally, cogeneration offers little or no dispatchability, and is a mediocre match with natural load shape generally. However, a cogeneration plant that operates only during the daytime would have a good to very good match with natural load shape, and would make a good contribution to capacity. Overall, cogeneration otters the same contribution as other baseload resources, unless the utility cannot rely on its cogeneration energy being available, which would reduce the capacity contribution.

Costs

Regional estimates of cogeneration prepared by BPA and the Northwest Power Planning Council used output of the Cogeneration Regional Forecasting Model (CRFM) as the principal source. This model matches cogeneration technologies with facility types for subregions in the Northwest. The program performs a cost/benefit analysis for a subset of the configurations appropriate for each facility type. The objective is to find the configuration, operating mode, and system size that maximizes the internal rate of return as seen by the project sponsor. This process yields a distribution for a supply of cogeneration as a function of internal rate of return. This is then converted to a quantity of cogeneration at different sell-back prices. The price that a utility has to pay for cogeneration is treated as a cost from a supply forecast perspective. This information was reduced to four cost categories (see Table 3-22). The difference between Cogen-1 through Cogen-4 is a difference in cost only; no inference should be made regarding the type of fuel or generation technology.

Table 3-22 Costs & Supply - Cogeneration (1988$)

	Cogen-1	Cogen-2	Cogen-3	Cogen-4
Real Levelized Costs (mills/kWh)	30	35	40	45
Nominal Levelized Costs (mills/kWh)	60	70	80	90
eaST (a)				
Real Levelized Costs (mills/kWh)	32	37	42	47
Nominal Levelized Costs (mills/kWh)	49	57	64	72
REGIONAL POTENTIAL (aMW)	125	500	1,000	4,000

(a) The cogeneration potential is assumed to be evenly split between the east side and the west side of the Cascades. This split is based on the distribution of industrial and commercial cogeneration potential as reflected in the Cogeneration Regional Forecasting Model (CRFM), which is the primary tool used by the Council and BPA to forecast the cost and availability of cogeneration potential.

Environmental Effects and Mitigation

Environmental effects of cogeneration (Figure 3-7) depend primarily on the type of fuel used. New cogeneration plants sited in the region could use a variety of fuels, but the primary fuels are natural gas, biomass, and solid waste. Natural gas is the fuel that would most likely be used for a new CT sited in the region.

Figure 3.7
Environmental Effects and Mitigation - Cogeneration

Figure (Page E53 Environmental Effects and Mitigation - Cogeneration)

Plant emissions for biomass, coal, natural gas, or other fuels would be similar to any combustion facility using these fuels. Compared to large central power stations, though, emissions would be of much smaller scale and very much localized. While emissions may be less concentrated and more dispersed, however, they are likely to be found within large population areas, whereas large central power plants are often remote from population centers. Typical air emissions of natural gas-fueled cogeneration include NOx, CO, and CO_2.

Cogeneration plants generally use water for cooling. Cooling tower blowdown may contain trace amounts of metals or chemicals used to control algae growth, and would generally require treatment before discharge. In addition, there may be water quality impacts associated with leachate from ash or solid waste when wood mass or solid waste are used a fuels.

Because cogeneration plants satisfy thermal energy as well as electricity needs with a single energy source, there is less overall pollution than if separate energy sources were used for these purposes. Cogeneration fuel sources tend to get stretched to maximize the use of the available energy; less energy is wasted.

On the other hand, multiple small units may be less efficient than a large

single unit for the same level of production. This may be the case for installations that produce excess electricity beyond the amount matched to the secondary thermal load for a site. In this case, the byproduct--thermal energy--made available through cogeneration is not used as efficiently.

Another issue, sometimes overlooked, is that developing small-scale electricity supplies, such as packaged cogeneration units, may exclude the opportunity to concentrate on energy efficiency in buildings. Gains in energy efficiency are also likely to reduce pollution, since less generation and, therefore, less fuel combustion is required to meet an equivalent level of electrical service. In addition, small units may not always have pollution controls as sophisticated as may be installed on large-scale units.

Examples of potential fuel cycle impacts for solid waste and wood biomass-fueled cogeneration are shown in Tables 3-23 and 3-24. Natural gas is the fuel that would most likely be used for a new cogeneration facility in the region. Examples of potential impacts from natural gas combustion can be found in Table 3-26.

Table 3-23 Potential Annual Routine Environmental Impacts Per Average Megawatt of Energy Generation For Solid Waste Combustion

Potential Impacts	Generation

Air Pollutants (a)	
Sulfur Oxides (tons)	15.03
Oxides of Nitrogen (tons)	77.36
Particulates (tons)	3.31
Carbon Monoxide (tons)	2.96
Carbon Dioxide (tons)	14,612 (b)
Water Quality Impacts	Undetermined, although leachate from ash and solid waste may be significant.
Thermal Discharge	Varies significantly
Land Effects (c)	
Acreage Requirements	2 per MW capacity corrected for capacity factor
Waste Streams	3,018.8 tons of ash (d)
Approximately 80% of solid waste fuel is consumed -- 20% remains as ash	
Employment (c)	
Construction (employee-years per MW capacity)	29
Operations (employees per MW capacity)	4.5
Occupational Safety and Health	undetermined

(a) Air quality estimates taken from measured emissions of the Marion County facility in Oregon as reported in Khalil, M.A.K., T.P. Steen, R.J. O'Brian, H.T. Osterrud, T.B. Stibolt Jr., F.P. Terraglio, and D.P. Thompson. 1988. Health Impact Review Panel: Report on the Trash Incineration Facility Proposed for Columbia County, Oregon. Metropolitan Service District, Portland, Oregon.

(b) Estimated carbon dioxide emissions from Taylor, H.F. 1991. "Comparison of Potential Greenhouse Gas Emissions from Disposal of MSW in Sanitary Landfills vs. Waste-to-Energy Facilities." in Municipal Waste Combustion. Air and Waste Management Association, Pittsburgh, Pennsylvania.

(c) See sources and calculations in Appendix F to this eis. Eighty percent capacity factor assumed.

(d) Andrews, J.C. 1991. "Incinerator Ash Disposal in the Tampa Bay Region." In Municipal waste Combustion. Air and Waste Management Association, Pittsburgh, Pennsylvania.

Table 3-24 Potential Annual Routine Environmental Impacts Per Average Megawatt of Energy Generation For The Wood Biomass Fuel Cycle (a)

Potential Impacts	Mining and Processing	Transportation	Generation
Air Pollutants			
Sulfur Oxides (tons)	Fossil-fueled	Transport by truck	0.57 (f)
Oxides of Nitrogen (tons)	equipment will	or train will result in	9.94 (f)
Particulates (tons)	release pollutants.	pollutants from	1.88 (f)
Carbon Dioxide (tons)	Reduced slash	fossil fuels.	13,183 (f)
Carbon Monoxide (tons)	burning will improve		18.7 (f)
Thermal Discharge (tons)	air quality in		51,612.9 (b)
	forests.		
Water Quality Impacts	Forest harvest may		
Consumption (acre-ft)	contribute to		54.3
General Effluent (acre-ft)	erosion.		28.7
Thermal Discharge			Varies significantly
Land Effects (c)	1,775 acres of		2.63 per MW capacity
Acreage Requirements	70-year-old forest		corrected for capacity
	needed per year to		factor
	supply 25% of fuel needs; potential loss of wildlife habitat and up to 125,000 pounds of nitrogen from soil. (e)		
Waste Streams	75% of fuel		108
Solid Wastes	expected from mill wastes (d)		

Employment (c)
Construction (employee-
9.6
years per MW capacity)
Operations (employees per
4.5 (a)
MW capacity)

Occupational Safety
and Health (d)
O&M Injuries 3.224 x 10E-4 4x10E-7
6x10E-7 to 2x10E-6
to 2.6x10E-6
O&M Deaths 2 x 10E-6
5.4x10E-9 to 4.5x10E-8
Construction Injuries 0 to 1.5x10E-9
1.6x10E-7 to 4.5x10E-6
Construction Deaths
3x10E-9 to 1.7x10E-8

(a) Unless otherwise indicated, these generic estimates are adapted from: U.S. DOE. 1983. Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors. D0E/EP-0093. Washington, DC.
(b) Flue gas.
(c) See sources and calculations in Appendix F to this eis. Eighty percent capacity factor assumed.
(d) Adapted from Arthur D. Little. 1985. Analysis of Routine Occupational Risks Associated with Selected Electrical Energy Systems. ea-4020. Electric Power Research Institute, Palo Alto, California.
(e) Adapted from ECO Northwest, Ltd., Shapiro and Associates, Inc., and Seton, Johnson, and 0dell, Inc. 1986. Estimating Environmental Costs and Benefits for Five Generating Plants. D0E/BP-11551-2. Bonneville Power Administration, Portland, 0regon.
(f) Adapted from Northwest Power Planning Council. 1991. Northwest Conservation and Electric Power Plan, Volume II, Part II, Portland, Oregon.

Supply Forecast

The Cogeneration Regional Forecasting Model (CRFM) was used as the primary data source for the regional estimates of cogeneration supply prepared by BPA and the Northwest Power Planning Council. The model's objective is to find the configuration, operating mode, and system size that maximizes the internal rate of return as seen by the developer. This process yields a distribution for a supply of cogeneration as a function of internal rate of return. Assumptions are made regarding penetration rates (actual decisions to install the Cogeneration equipment) at different levels of return. This penetration curve is used to reduce the distribution of supply to an expected value for developed cogeneration and the results are aggregated to a regional level. Table 3-22 shows the quantity of cogeneration projected at given prices.

The output of this process is a generic planning estimate of the potential cogeneration. There is no site- or project-specific information in the output.

3.2.2.2 Combustion Turbines

Technical Description

Combustion turbines (or CTs, also called gas turbines) are the same technology used in jet engines. In the basic CT design, air enters a compressor, which packs large amounts of air into a combustor at high pressure. In the combustor, fuel is added to the air and burned, releasing heat energy and producing a high-temperature, high-pressure exhaust gas. This gas is expanded through a turbine, which powers a generator and the compressor.

Natural gas or distillate oils are the primary fuels used in combustion turbines. Gasified fuels, such as the syngas derived from coal, are also potential fuel candidates. (Gasified coal is covered under "Coal" later in this chapter.) The heat rate (or efficiency) for gas turbines is about the same as steam turbine generators. However, CT thermal efficiency is improving as the technology improves and CTs gain the flexibility of conversion to combined-cycle operation.

The inefficiency of a combustion turbine can be seen in the high temperatures of the gases discharged from the turbine. There is significant available energy in the exhaust gases, which can be recovered through a heat recovery process. One way to take advantage of this available energy is to use steam injection (which also has the benefit of reducing NOx emissions). In a steam-injected turbine, hot exhaust gases are recirculated to heat pressurized water into superheated steam. The steam is then injected into the combustor of the turbine and mixes with compressed inlet air. The additional inlet steam helps drive the turbine.

CT efficiencies can also be improved by using multi-stage compressors with inter-cooling between stages and by operation at higher turbine inlet temperatures. Currently, turbines achieve temperatures around 2,000 degrees F, but improvement in heat-tolerant materials can increase this limit to more than 2,300 degrees F.

The high thermal energy in the turbine exhaust makes CTs ideal in cogeneration applications where high-grade process heat is used in addition to electricity. Another way to take advantage of the energy in the exhaust gases is to use the combustion turbine as the "topping cycle" in a combined cycle plant. (Cogeneration is covered earlier in this chapter.)

Combustion turbine technology is proven and widely used. Simple cycle CT designs are basic, reliable, and relatively easy to site. They can be installed with minimum site renovation and preparation because they are compact and generally

do not require additional equipment, such as cooling towers or elaborate fuel processing subsystems.

A combined cycle combustion turbine (CCCT) combines a combustion turbine with a steam cycle plant to generate power very efficiently. Electricity is first generated from the combustion turbine. The exhaust gases from the CT then become the beat source for raising water to steam in a steam cycle system. The combustion turbine cycle is referred to as the "topping cycle," and the steam turbine cycle as the "bottoming cycle."

Combined cycle plants are designed to maximize the thermal efficiency of a power plant by using the available energy in the combustion turbines high-temperature exhaust gases. The key to the combined cycle is the heat recovery steam generator system, which takes the place of the steam cycle boiler. Typical steam conditions in a heat recovery steam generator are 900 to 1,000 degrees F and 1,000 to 1,500 pounds per square inch. Instead of rejecting heat to the environment at gas turbine temperatures of more than 1,000 degrees F, the combined cycle eliminates heat at the steam cycle condenser temperature, which is the temperature of available cooling water--approximately 50 to 70 degrees F.

Operating Characteristics and Capacity Contribution

Combustion turbines can be operated to meet both peak and energy loads. CTs can quickly respond to load demand changes; however, maximum efficiencies are obtained when operating at design capabilities. Because of high fuel costs, CTs tend to be used at a constant rate for a limited period of time. CTs can be quickly fired up and have proved effective in meeting short-term peak loads and load fluctuations due to extreme weather conditions.

CT availability factors run 80 to 90 percent. CTs are candidates for meeting base loads and can also be used in firming applications. Simple CTs operate at heat rates of 11,000 to 12,000 Btu/kWh. Combined cycle applications operate at heat rates of 7,500 to 8,500 Btu/kWh. CTs used to "firm up" or supplement the nonfirm hydropower operate at capacity factors of 15 to 40 percent. When operated to meet short-duration capacity needs, CTs operate at relatively low capacity factors (on the order of 5 percent).

Combustion turbines offer very good dispatchability. A combustion turbines contribution to capacity depends on policies governing its operation. If operated for energy, the plant would probably be run flat-out unless non-firm energy were available to displace it. In this mode, a CT would provide a little additional capacity. If it were operating, it could be ramped down at night, reducing problems of returning energy to the Northwest hydroelectric system (though this would decrease the amount of energy obtained from the CT, postulated to be operated for energy). If it were being displaced, it could still be fired up to run during the day, providing additional peak energy. This contribution could not be relied upon during low water, however.

If operated for capacity a combustion turbine would meet peak loads but provide less total energy throughout the year. For example, at an expected capacity factor of 50 percent, a CT could provide extra capacity in several modes. One mode would be to operate it at 50 percent per day, running at maximum during the day and much lower at night. Another mode Would be to use a CT to recharge the hydro system when it is drawn down to meet prolonged heavy loads (e.g., during a cold snap). The CT would be kept idle perhaps half of the weeks of the winter, but turned on for maximum, flat operation during cold weather, allowing the reservoirs to refill and increase their capacity effectiveness by increasing the head at each reservoir.

Costs

Cost estimates shown in Table 3-25 are based on documentation contained in a July 1988 report, Development of Combustion Turbine Capital and Operation Cost, prepared for BPA by Fluor Daniel, Inc. The Cost of power resulting from using nonfirm energy with CTs is dependent on the amount of nonfirm energy available, the value of nonfirm energy, and the cost and availability of fuel to operate such CTs.

Table 3-25 Costs - Combustion Turbines (1988$)

Capital Cost ($/kW)	
Simple Cycle	66 (a)
Combined Cycle	747 (a)
O&M Cost	
Fixed ($/kW-yr)	
Simple Cycle	3.06
Combined Cycle	7.51
Variable (mills/kWh)	
Simple Cycle	(b)
Combined Cycle	(b)
Real Levelized Costs (mills/kWh)	(c)

Nominal Levelized Costs (mills/kWh) (c)

(a) These capital cost estimates include a $120/kW transmission adder, which reflects siting on the east side of the Cascades.
(b) The variable costs have been loaded into the fixed costs.
(c) Combustion turbine cost depends on how they are used. When displaced by nonfirm hydro power, combined cycle CTs have a cost of 26 to 34 mills/kWh (real).

Environmental Effects and Mitigation

The primary environmental effects of CTs are shown in Figure 3-8. CTs that use natural gas are relatively clean burning. Only NOx emissions tend to be a problem because of the high combustion temperatures, but significantly less so than in coal combustion. NOx can be controlled with either water or steam injection into the CT combustor, eliminating up to 80 percent of the NOx. Water use and visible steam plumes in this case become an environmental concern, but water use can be minimized by re-using the condensed exhaust steam for steam injection.

Figure 3-8
Environmental Effects and Mitigation - Combustion Turbines

Figure (Page E60 Environmental Effects and Mitigation - Combustion Turbines)

If oil fuels are used, there is some sulfur dioxide pollution. SOx exhaust gas can be mitigated with scrubbers, which add to the cost of CTs. As in all combustion technologies, significant amounts of CO_2, a "greenhouse" gas, and waste ,heat are produced. Simple cycle CTs reject waste heat directly to the atmosphere, so cooling water is not required.

Because CTs are often sited close to where gas transportation and transmission lines meet, effects On urban environments need to be considered. As with jet planes at airports, CT noise can be a problem. Noise levels of unsilenced

CTs can run 65 to 70 decibels at 1,200 feet from an operating turbine. Silencing packages can reduce this to 51 decibels at 400 feet.

Environmental impacts for combined cycle plants are the combined impacts of waste heat boiler plants and combustion turbines. For the amount of fuel combusted, though, plant efficiencies are proportionately higher, and, therefore, the environmental impacts are proportionately less.

Examples of potential environmental impacts for the gas-fired combustion turbine fuel cycle are shown in Table 3-26.

Table 3-26 Potential Annual Environmental Impacts per Average Megawatt Per Year of Energy Generation for the Natural Gas-Fired Combined Cycle Combustion Turbine Fuel

Potential Impacts	On-Shore Gas	Transportation	Generation
Air Pollutants			
Sulfur Oxides (tons)	0.95	0.0004 tons	0.03 (d)
Oxides of Nitrogen (tons)	0.056	0.266 tons	5.81 (d)
Particulates (tons)	0.0013		0.03 (d)
Carbon Dioxide (tons)			3,904.95 (d)
Carbon Monoxide			2.23 (e)
Water Quality Impacts			
Consumption (acre-ft)			3.4 (f)
Discharge	0.0058 acre-ft drilling mud		0.0081
Biological Oxygen Demand (tons)	0.0011 0.0074		0.651

Chemical Oxygen Demand 0.0228
(tons) 0.00006
Oil and Grease (tons) 0.00002
Chromium (tons)
Zinc (tons)
Total Dissolved Solids (tons) 0.305
1.06
Total Suspended Solids
1.14
(tons)
Ammonia (tons)
0.00012
Chloride (tons) 0.057
Sulfate (tons) 0.046

Thermal Discharge
28,800

Land Effects (b)
Acreage Requirements .025 Permanent 4.18
0.15 per MW capacity
.032 Temporary
corrected for capacity
Waste Streams
Solid Wastes (tons) 2.24 (Drill Cuttings)
undetermined

Employment (b)
Construction (employee- .029 0.45
1.4 (per MW capacity)
years)
Operations (employees per .003 0.013 employees
0.1 (per MW capacity)
year)

Occupational Safety
and Health (c)
O&M Injuries 7.7x10E(-8) to 2.174x10 1.06x10E(-7) to
3.4x10E(-6) to 6.34x10E(-5)
E(-6) to 1.7x10E(-7)
O&M Deaths 9x10E(-10) to 2.23x10 3x10E(-10) to
3x10E(-9) 2.5x10E(-8) to 1.1x10E(-6)
E(-8)
Construction Injuries
6.8x10E(-6) to 9.88x10E(-5)
Construction Deaths
2.23x10E(-8) to 4x10E(-7)

(a) Unless otherwise indicated, these generic estimates are taken from: U.S. DOE. 1983. Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors. DOE/EP-0093. Washington, DC.
(b) See sources and calculations in Appendix F to this eis. Sixty-five percent capacity assumed.
(c) Adapted from Arthur D Little. 1985. Analysis of Routine Occupational Risks Associated with Selected

Electrical Energy Systems. ea-4020. Electric Power Research Institute, Palo Alto, California. Generation estimates for a natural gas fuel cell.

(d) From BPA's emission estimates for environmental costs and planning.

(e) Adapted from Northwest Power Planning Council. 1991. Northwest Conservation and Electric Power Plan, Volume II-Part II.

(f) Flow rate requirements taken from Fluor Daniel, Inc. 1988. Development of Combustion Turbine Capital and Operating Costs. DOE-BP-63056-1. Bonneville Power Administration, Portland, Oregon.

Supply Forecast

The quantity of combustion turbines installed is not inherently limited. Constraints that are typically discussed include ability to site and availability of fuel supply. These constraints will not impose an impediment for the first several hundred megawatts. For this eis, 1,680 MW of CCCT capacity (1,394 aMW energy) is considered to be available to the region, of which 1,260 MW capacity and 1,046 aMW energy would be available to BPA. It is possible to initially install simple cycle CTs that are configured for conversion to combined cycle units.

3.2.2.3 Nuclear Fission - Completion of WNP-1 and WNP-3

Technical Description

During a fission reaction, the uranium atoms (235 and 238) are split apart, forming new elements and releasing heat. The accumulation of millions of these reactions can be used to produce steam, which turns a turbine generator and produces electricity.

Commercial nuclear power plants use the steam cycle and have two basic designs: the pressurized water reactor (PWR), and the boiling water reactor (BWR). The PWR design uses three separate, sequential, heat transfer systems. The first is the reactor coolant system that circulates high-pressure hot water from the hot reactor core to the steam generator heat exchanger. The steam generator heat exchanger is the second system, where heat from the reactor coolant on the primary scale boils water on the heat exchanger secondary scale to create steam, which is then used to drive the turbines. The third system condenses the steam from the turbine and discharges the excess heat to the environment. These three systems are designed to have no fluid exchange, only heat transfers.

Boiling water reactor designs use two sequential systems. The first system circulates water through the reactor core itself, where steam is produced and then introduced directly to the steam turbines. After expanding through the turbines, the steam is exhausted to the condensers, where it is cooled and then sent back through the reactor. A separate water system brings cooling water to the condenser. In both the BWR and PWR systems, heat from the condensers is discharged to the atmosphere by evaporating water in cooling towers (mechanical or natural), which reject the heat by evaporating water.

Nuclear fission power is a proven commercial technology, with reactors on-line since the 1950s. As of mid-1989, there were 110 reactors in operation in the United States, with a combined capacity of 97,182 MW, producing nearly 20 percent of the nation's electricity.

There are only two commercial nuclear plants operating in the Pacific Northwest: the Trojan plant on the Columbia River near Rainier, Oregon, and the Washington Nuclear Power Plant (WNP-2) on the Hanford Reservation near Tri-Cities, Washington. The Trojan plant is a 1,178-MW (gross) pressurized water reactor plant in service since 1976. The 1,154-MW (gross) WNP-2 facility is a boiling water reactor plant with an in-service date of 1984.

WNP-1 is a 1 ,250-MW net capacity PWR commercial nuclear plant, designed by Babcock & Wilcox, located on land leased from the U.S. Department of Energy on the Federal Hanford Nuclear Reservation about 10 miles north of Richland, Washington. WNP-1 is about 65 percent completed. It has been in a preserved state since construction was suspended in 1982.

WNP-3 is a 1,240-MW net capacity PWR commercial nuclear plant, designed by Combustion Engineering, located near Satsop in Grays Harbor County, Washington. WNP-3 is about 75 percent completed. It has been in a preserved state since July 1983, when construction was suspended.

Operating Characteristics and Capacity Contribution

Nuclear plants are best operated in baseloaded mode at their rated output. Like all steam cycle plants, nuclear plants have a large start-up inertia and cannot respond quickly to changes in load demands. Most nuclear projects are available to meet capacity and energy loads for about 10 months per year. For approximately 2 months, these projects are down for maintenance and refueling. Pacific Northwest nuclear projects are typically down in the late spring. During these outages, the lost power is made up by the Pacific Northwest hydropower system, which has increased streamflows during this timeframe. Nuclear plants typically have availability factors of 60 to 70 percent, depending on project type. Nuclear power plants offer no dispatchability and provides only a mediocre match to natural load. They provide somewhat less capacity contribution than other baseload plants because they are more subject to lengthy, unplanned outages.

Costs

As a result of public input received during review of its draft 1990 Resource Program, BPA recommended deferral of a new comprehensive study of the future of WNP-1 and WNP-3 until significant information becomes available or conditions change sufficiently to warrant a new study.

Detailed cost-to-complete-construction estimates were prepared by the Washington Public Power Supply System (WPPSS or Supply System) and its contractors in 1984. In 1986, the Supply System updated the 1984 estimates in support of BPA's 1987 Resource Strategy. Operation and Maintenance (O&M) cost estimates were also reviewed in 1986. Table 3-27 summarizes the capital and O&M cost assumptions in 1988 dollars. The Northwest Power Planning Council reviewed O&M costs for nuclear power plants for its Draft 1991 Northwest Conservation and Electric Power Plan. It reported that, although O&M costs escalated rapidly from 1974 to 1984, escalation has peaked and declined in later years. The Council assumes that the real rate of O&M cost escalation will decline from 3.5 percent annually in 1986, to zero percent (real) by 2000. (The Council's 1986 cost estimates are inflated to 1988 dollars for analysis purposes.)

Table 3-27 Costs - WNP-1 and WNP-3(1988$)

Cost	WNP-1	WNP-3
Capital Cost ($/kW)	1,325	1,054
O&M Cost		
Fixed ($/kW-yr)	78.85	84.15
Variable (mills/kWh)	6.75	6.75
Real Levelized Costs (mills/kWh)	35	34
Nominal Levelized Costs (mills/kWh)	67	65

A number of nuclear reactor vendors are developing enhanced or advanced reactor designs with the hope of receiving NRC Certification in the 1995 to 2000 timeframe (see section 3.4.3). When BPA reviews its position on the future of the nuclear option, it will consider any new/advanced technology available at that time, as well as economics, safety and nuclear waste disposal (NRC responsibilities), and other environmental impacts.

In April 1991, the Council released its 1991 Power Plan, which included an objective to determine the cost and availability of resources in the region in the next

20 years. Such resources, among others, include Washington Nuclear Projects (WNP) 1 and 3 (the Projects). The Council recommended that BPA and the Supply System undertake the work necessary to determine how to resolve outstanding issues so that the Council can make an informed judgment in the next Power Plan (1994-96) whether to continue preserving the Projects, to construct either of the Projects if needed, or to terminate them, if appropriate.

In response to the Council's recommendation, the Supply System and BPA agreed to study the viability of the Projects as resource options. Three initial areas were identified as having potentially significant impact on the viability of the Projects, namely, (1) institutional issues, (2) the NEPA process, and (3) critical path analysis:

(1) The institutional issues include potential litigation that may impact the Supply System's ability to finance completion of the Projects. Certain Project participants have alleged that the Projects have been terminated and under existing Net Billing Agreements would not be obligated for the repayment of bonds sold to finance completion of the Projects. While BPA's General Counsel, the Supply System's Chief Counsel and the Bond Counsel to the Supply System agree that neither Projects nor the Net Billing Agreements have been terminated, there is potential for litigation to resolve the issue. BPA and the Supply System have agreed to identify potential alternatives for resolution of this issue.

(2) BPA took the lead in addressing the NEPA process issue by hiring a consultant to conduct an independent review of the existing NEPA requirements; The draft report from the study did not identify any new issue that would be an insurmountable obstacle to completion of the Projects. It did conclude that it would likely take 2 years to complete a site-specific draft eis, which would put the NEPA process on the critical path for a 6-year completion schedule if a decision was made now to complete either project.

(3) The Supply System issued a task order for the architect-engineer contractors to develop a critical path analysis for a 6-year completion schedule for the Projects. The critical path analysis verified that the plants could be completed

in a 6-year construction schedule and the specification and contract for the

simulator is on the critical path. The simulator must be operational for operator training prior to fuel loading.

Environmental Effects and Mitigation

The environmental impacts of nuclear energy fall into the categories of mining uranium ore and fuel processing, plant construction, electricity production, and waste disposal. The primary environmental effects of nuclear power are shown in Figure 3-9.

Figure 3-9
Environmental Effects and Mitigation - Nuclear

Figure (Page E66 Environmental Effects and Mitigation - Nuclear)

Uranium is mined in open pits. Exploration, drilling, and blasting in mining operations can disrupt the local ecology and contaminate ground water. Radioactive uranium tailings must be disposed of properly, lest they contaminate water supplies or air quality. Land reclamation problems are similar to those of coal mining, but on a much smaller scale, since the energy content of uranium ore is of much higher density than that of coal. Miners must take precautions to avoid inhaling radioactive material, which carries the risk of inducing lung cancer or other respiratory problems (see Appendix A, Human Health Effects).

During construction, there are erosion and dust pollution impacts, and disruptions to the local economy. These are transitory and typical of large construction projects. Since WNP-1 and WNP-3 are already more than half completed, nearby communities have already experienced many of these construction impacts.

Nuclear plants require relatively large amounts of land. A relatively small portion of the land requirement is for the plant itself and site support (e.g., WNP-3 would require 185 acres). Larger exclusion areas (1,500 acres for WNP-3 and

2,150 acres for WNP-1) have restricted access and cannot be used for agriculture or urban or industrial development. Such exclusion areas can provide open space and habitat for wildlife.

The primary impacts from operating a nuclear power plant include the release of heat and moisture from the plant cooling system, cooling tower drift, and airborne radioactive materials. Impacts related to heat rejection (e.g., water vapor plume, cooling tower drift, cooling tower blowdown) are common to all thermal power plants.

Radioisotopes are products formed as a result of uranium and plutonium fission in the reactor. These include actinides and activation products. Actinides are the isotopes of elements having atomic weights of 89 and greater. Activation products include radioisotopes formed by the neutron flux during reactor operation. The containment building of a nuclear reactor is designed to withstand severe natural forces, especially seismic activity, so that even if pipes break, any released radionuclides will be contained. In the event of a loss in reactor cooling, there is a potential for the core to overheat; however, the primary cooling system is backed up with diverse and redundant systems to prevent this from occurring.

Gaseous radioactive effluents include fission product isotopes of noble gases--krypton, neon, and argon (the primary source of direct, external radiation emanating from a plant's effluent plume)--and carbon-14, tritium, and radioiodines. These products can be controlled through filtration and by collecting them and allowing them to decay to acceptable radiation levels before they are released. Particulates--such as the fission products of cesium and barium, activated products of cesium and barium, and activated corrosion products such as cobalt and chromium--are captured by filtration and then disposed of with solid radioactive waste.

Besides airborne gas releases, there may be some unplanned releases of particulates or waterborne radioactive materials, including fission products such as nuclides of strontium, and activation products such as sodium and manganese, and tritium.

Experience in the design, construction, and operation of nuclear power plants indicates that the average annual release of these kinds of radioactive materials and effluents typically will be a small percentage of the limits specified by

Federal safety regulations. All aspects of nuclear power plants are continuously monitored to ensure that allowable limits are not exceeded.

Other potential water-related effects of nuclear power plant operation include thermal discharges, water consumption, and release of waterborne chemical pollutants. Make-up water in cooling towers tends, overtime, to concentrate mineral salts and other contaminants in the coolant system. These are controlled with continuous "blowdown" to introduce fresh coolant. Blowdown can be environmentally damaging but can also be treated to remove impurities. Blowdown discharges are continuously monitored and must meet strict standards for discharge.

Radioactive waste disposal continues to be a problem. Waste is classified as high-level, transuranic, or low-level. High-level waste has high concentrations of beta- and gamma-emitting isotopes and significant concentrations of transuranic materials, including plutonium. Spent fuel is the Only reactor product that falls into this category. Reactors produce about 400 cubic feet per year of spent fuel. Transuranic wastes have low levels of beta and gamma emissions but significant concentrations of transuranic isotopes. Transuranic wastes are produced during reactor operation, but remain contained within the fuel elements unless the cladding is breached.

Finally, low-level wastes are characterized by a low level of beta or gamma emissions and insignificant concentrations of transuranic materials. These wastes may become radioactive during normal operations. Low-level wastes include clothing, paper, spent ion-exchange resins, filters, and evaporator concentrates from isolated parts of the reactor building. Generally, these wastes are disposed of by allowing them to decay, then diluting them to acceptable concentrations that are much less than those that occur naturally. These wastes are then disposed of in a specially designed and controlled burial site.

Although operational and safety risks can be addressed, long-term disposal of high-level nuclear wastes remains an unresolved problem. In 1982, Congress passed the Nuclear Waste Policy Act making the Federal Government responsible for the ultimate disposal of high-level nuclear wastes, which include the spent fuel from power plants. There have been delays due to state resistance and management problems. To date, no long-term storage facility has been established.

Examples of potential environmental effects of the nuclear fuel cycle are shown in Table 3-28.

Table 3-28 Potential Annual Environmental Impacts Per Average- Megawatt of Energy Generation Per Year of Generation for the Nuclear Fuel Cycle (a)

Potential Impacts	Mining and Processing	Transportation	Generation
Air Pollutants			
Sulfur Oxides (tons)	5.2		
Oxides of Nitrogen (tons)	1.396		
Particulates (tons)	1.51		
Carbon Monoxide (tons)	0.035		
Fluoride (tons)	0.0007		2.6
Radionuclides (curies)	4.81		
Fossil Fuel Emissions (tons)			0.076
Airborne water			3,800,000 gallons
Water Quality Impacts			
Consumption (acre ft)	.993		16
Sulfate	5 (tons)		315.00 mg/l (b)
Manganese	0.01 (tons)		28.45 /l (b)
Chloride	0.011 (tons)		17.75 mg/l (b)
Iron	0.17 (tons)		243.00 (b)
Selenium	0.00026 (tons)		
Calcium	0.0079 (tons)		81.55 mg/l (b)

Fluoride 0.0365 (tons)
0.76 mg/l (b)
Nitrate 0.032 (tons)
Alkalinity as CaCO3
47.00 mg/l (b)
Ammonia as N 0.014 (tons)
0.08 mg/l (b)
Hardness as CaCO3
202.00 mg/l (b)
Magnesium
22.75 mg/l (b)
Phosphorous
0.49 mg/l (b)
Potassium
4.00 mg/l (b)
Sodium 0.015 (tons)
23.35 mg/l (b)
Total Dissolved Solids
786.00 mg/l (b)
Total Suspended Solids
12.90 mg/l (b,e)
Cadmium
1.61 /l (b)
Chromium
15.66 /l (b)
Copper
116.15 /l (b)
Lead
7.44 /l (b)
Mercury
1.88 /l (b)
Nickel
31.15 /l (b)
Zinc
62.35 /l (b)
Radionuclides (curies) 0.739
0.302 curies

Thermal Discharge 954
42,000
(MMBtu)

Land Effects (c)
Acreage Requirements 0.357
2.26 per MW capacity

corrected for capacity

factor (includes

exclusion areas)

Table 3-28, continued:

Potential Impacts	Mining and Processing	Transportation	Generation
Waste Streams			
Overburden and Tailings (tons)	8.3		
Chemical Wastes (tons)	0.79		
Radionuclides (curies)	0.130		0.0058
Employment (c)			
Construction (employee-years per MW capacity)	1.078		1.8
Operations (employees per MW capacity)	0.277	0.513	0.9
Occupational Safety and Health (d)			
O&M Injuries	13.8x10E(-7) to 38x10E(-7)	1x10E(-7) to 16x10E(-7)	1x10E(-7) to 16x10E(-7)
O&M Deaths	2.7x10E(-8) to 5.16x10E(-8)	0 to 1.5x10E(-9)	1.2x10E(-9) to 2x10E(-9)
Construction Injuries			21x10E(-7) to 44.7x10E(-7)
Construction Deaths			3x10E(-10) to 5.82x10E(-8)

(a) Unless otherwise indicated, these generic estimates are adapted from: U.S. DOE. 1983. Energy Technology Characterizations Handbook Environmental Pollution and Control Factors. DOE/EP-0093. Washington, DC.

(b) Concentrations in cooling water blowdown, assuming 5 cycles for WNP-1 and 6 cycles for WNP-3. Source: Washington Public Power Supply System. Environmental Reports for Operating Licenses for WNP-1 and -4. 1982.

(c) See sources and calculations in Appendix F to this eis. Sixty-five percent capacity factor assumed.

(d) Adapted from Arthur D. Little. 1985. Analysis of Routine Occupational Risks Associated with Seated

Electrical Energy Systems. ea-4020. Electric Power Research Institute, Palo Alto, California.

(e) The Supply System reports that TSS from WNP-2 have typically been less than 50 mg/l (Carl Van Hoff, letter of July 2, 1992).

Supply Forecast

For purposes of this document, WNP-1 and WNP-3 are considered to be available for completion. This is the same assumption that was used in BPA's 1990 Resource Program.

3.2.2.4 Coal Conventional Coal Technical Description

Conventional coal plants use the same technology as steam cycle plants fueled with oil, biomass, natural gas, or municipal solid waste. One important distinction between coal-fired plants and other steam cycle plants using these fuels is the significant effort required to process fuel, treat emissions, and dispose of wastes that are peculiar to coal.

In a conventional steam cycle coal plant, heat from coal combustion is transferred to water in a boiler. The boiler changes water under high pressure to high-temperature steam. The steam expands through a turbine, which drives a generator. After passing through the turbine, the steam is condensed to water again, then pumped back into the boiler with a feedwater pump to complete the cycle.

The same technologies used to increase efficiencies in other steam cycle plants--regenerative cycles, superheat, and reheat--are used in coal plants.

Coal deposits are found in seams. Coal comes in many varieties and grades, with varying concentrations of sulfur and ash. The coals available to the Northwest

include those from the East Kootenay coal field in British Columbia, the Powder River coal field in eastern Montana and Wyoming, and the Uinta coal field in Utah and Colorado. All of these coals have low (less than 1 percent) sulfur content.

Because coal is a solid, it is pulverized, then blown into special burners to fire steam boilers.

Coal technology is well established and a prominent power source worldwide. During 1988, 56.9 percent of the electricity generated in the United States came from coal plants. Coal plants are generally designed as large, centralized units, typically sized to 250 MW or more. Often, plants are located near mining sites for easy access to the fuel, but may be just as well located near large transmission lines.

Table 3-29 summarizes the surrogate sites and corresponding coal sources for the five plant sites. These sites were selected because there is current or proposed coal plant activity. They are not the only sites where a coal plant could be constructed. However, they are representative of the areas where development would be likely to occur.

Table 3-29 Assumed Coal Sites and Coal Sources

	Coal-1	Coal-2	Coal-3	Coal-4	Coal-5
Surrogate Site	Colstrip	Creston	Boardman	Thousand Springs	Western WA/OR
Coal Source	Colstrip	East Kootenay	East Kootenay	Thousand Springs	East Kootenay

Operating Characteristics and Capacity Contribution

Coal plants are designed as baseload power generators, with optimum performance at design load. Most coal plants are available to meet energy loads for about 11 months per year. For approximately 1 month per year, these projects are down for maintenance. Coal plants are not designed for short-term peaking operation. The thermal inertia of getting boilers, turbines, and condenser up to operating temperature inhibits quick response to variations in load. Coal plants typically have high availability factors of 75 to 85 percent. Capacity factors are assumed to equal 75 percent. For planning purposes, a heat rate of 10,856 Btu/kWh is assumed at design load.

Coal plants offer little dispatchability and provide only a mediocre match to natural load. They do provide a slightly greater contribution to capacity than nuclear, cogeneration, or geothermal, due to a marginally better dispatchability. A coal plant displaced for one or more months by availability of non-firm energy could be started up if extended cold weather caused a major draw-down of the hydro system. Thus, coal plants can contribute more to winter capacity than other baseload plants, but this contribution is not firm, since it could only occur when the coal plant has been idled.

Costs

Cost estimates for coal-fired resources are derived from documentation prepared for BPA's 1990 Resource Program. These costs are summarized in Table 3-30. The costs and characteristics of pulverized coal plants are composites of large and small plants. The costs are the average of the large (603 MW) and small (250 MW) twin plants.

Table 3-30 Costs - Conventional Coal (1988$)

	Coal-1	Coal-2	Coal-3	Coal-4	Coal-5
Capital Cost ($/kW)	1,995	1,776	1,789	2,042	1,758
Fixed ($/kW-yr)	25.58	29.35	30.29	31.31	31.48
Variable (mills/kWh)	3.5	3.8	3.8	3.8	3.8
Fuel Cost ($/MMBtu) (a)	0.48	1.24	1.39	1.29	1.61
Real Levelized Coats (mills/kWh)	37	44	46	48	49
Nominal Levelized Costs (mills/kWh)	73	87	91	94	97

(a) Fuel costs reflect transportation to the plant site.

Environmental Effects and Mitigation

Coal generation can have substantial impacts to air, land, and water (Figure 3-9).

Figure 3-10
Environmental Effects and Mitigation - Coal

Figure (Page E73 Environmental Effects and Mitigation - Coal)

Among the greatest environmental concerns of coal generation are the emissions of oxides of sulfur and nitrogen (SOx and NOx) and carbon dioxide (CO_2). SOx and NOx are, to some extent, precursors of acid rain. CO_2 is thought to be a "greenhouse" gas, which may have serious environmental impacts. (See Chapter 5 section 5.2.2 for discussion of global warming.) Although there are ways to scrub exhaust gases to reduce SOx and NOx, there is no effective way to mitigate CO_2 pollution. The region currently has about 3,200 aMW of coal-fired generation, much without significant scrubbing capability. Adding scrubbers would reduce SOx emissions by about 70 percent.

Coal combustion produces particulates, most of which can be removed with filters and electrostatic precipitators. Coal is also contaminated with trace amounts of heavy metals and radionuclides, such as lead, cadmium, arsenic, and radium-226, which vary with the source of coal.

If plants are sited remote from transmission grids, transmission lines must be built, and construction of power lines and substations introduces secondary environmental impacts.

Centralized thermal plants also require large quantities of cooling water to carry waste heat from plant condensers. There is a large, localized effect from a

central power plant. Air quality, transportation, burner waste, ash disposal, cooling water, noise, land disruption, temporary dust and erosion impacts during construction, and local economic effects are all expected impacts.

Table 3-31 presents the potential annual environmental impacts per megawatt per year of generation for pulverized coal.

Table 3-31 Potential Annual Environmental Impacts Per Average Megawatt of Energy Generation Per Year of Generation for the Pulverized Coal Fuel Cycle (a)

Potential Impacts	Mining and Processing	Transportation	Generation
Air Pollutants			
Sulfur Oxides (tons)	0.0075	0.12	9.51 (e)
Oxides of Nitrogen (tons)	0.1155	0.105	23.77 (e)
Particulates (tons)	0.006	3.36	1.43 (e)
Carbon Dioxide (tons)			9747.6 (e)
Carbon Monoxide (tons)	0.023	0.156	1.69 (f)
Fugitive Dust (tons)	0.017	10.4	
Heavy Metals (lbs)			1.13
Radium 226 (curies)			0.000006
Methane (tons)			7.01 (f)
Water Quality Impacts			
Consumption (acre ft)			10.69
Oil and Grease (tons)			0.034
Total Suspended Solids (tons)			
Chloride (tons)			0.06
Iron (tons)			0.00002
Copper (tons)			0.00002
General Discharge (acre ft)	0.20 (b) alkaline		
Thermal Discharge (MMBtu)			42,000
Land Effects (c)			
Acreage Requirements	0.25 per year Permanent change in landscape		1.33 per MW capacity corrected for capacity factor
Waste Streams			
Solid Wastes	1,940		
Boiler Bottom Ash			68
Boiler Fly Ash			202
Scrubber Sludge			86

Employment (c)
Construction (employee-   4.7
years per MW capacity)
Operations (employees per   0.195   0.513   0.5
MW capacity)

Occupational Safety
and Health (d)
O&M Injuries   14.5x10E(-7) to
6x10E(-7) to 2x10E(-6)
                              2.1x10E(-6)
O&M Deaths   2.7x10E(-8) to
1.3x10E(-9) to 4.5x10E(-8)
                              4.7x10E(-8)
Construction Injuries   9x10E(-8) to
1.7x1OE(-6) to 22.4x10E(-6)
                                             2.6x10E(-8)
Construction Deaths   1x10E(-9) to
3x10E(-10) to 5.82x10E(-8)
                                             4x10E(-9)

Footnotes, Table 3-31:
(a) Unless otherwise indicated, these generic estimates are adapted from: U.S. DOE. 1983. Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors. DOE/EP-0093. Washington, DC.
(b) Adapted from Argonne National Laboratory. 1988. Energy Technologies and the Environment DOE/EH-0077U. U.S. Department of Energy, Washington, DC.
(c) See sources and calculations in Appendix F to this eis. Seventy-five percent capacity factor assumed.
(d) Adapted from Arthur D. Little. 1985. Analysis of Routine Occupational Risks Associated with Selected Electrical Energy Systems. ea-4020. Electric Power Research Institute, Palo Alto, California.
(a) From BPA's emission estimates for environmental costs and planning.
(f) Adapted from Northwest Power Planning Council. 1991. Northwest Conservation and Electric Power Plan, Volume II, Part II, Portland, Oregon.

Supply Forecast

The amount of coal-fired generation that could be developed at all of the surrogate sites was limited to 4,800 aMW in BPA's 1990 Resource Program. This is the same limit that was used by the Northwest Power Planning Council for its draft 1991 Power Plan. This limit is based on a qualitative assessment of the constraints surrounding the development of the coal resource. The limits are assumed to be 1,800 aMW at the Colstrip site and 750 aMW at the remaining sites. BPA's supply was assumed to be 1,200 aMW.

High Technology Coal - (Fluidized Bed Combustion, Gasification)

Technical Description

Several advanced coal technologies offer better heat rates (higher thermal efficiencies) and greatly reduced emissions compared to the conventional steam cycle coal plant.

Atmospheric fluidized-bed combustion (AFBC) is an advanced coal technology that is gaining wide acceptance throughout the world. In a fluidized bed, a fluid such as air, steam, or oxygen is blown into a reactor vessel. With the help of a fluidizing agent such as sand, the fluid entrains fuel particles in its stream and bubbles or fluidizes them in the combustion zone of the reactor. This fluidizing effect promotes effective heat transfer and complete combustion. Limestone is mixed with coal in the fluidized-bed to trap the sulfur. Removal of much of the sulfur with this design reduces or eliminates flue gas clean-up of the combustion gases.

Pressurized fluidized-bed combustion (PFBC) reactors are operated at high pressures; the exhaust gases can then be used to supply a combustion turbine. Typical reactor conditions may be 16 atmospheres of pressure with a bed temperature of 1,580 degrees F. PFBC technology is now progressing to the demonstration stage, but still lags behind AFBC technology.

Coal gasification technology thermally decomposes solid coal into a high-quality gas fuel that can be burned in a combustion turbine. In gasification, the coal is partially oxidized, producing mostly Carbon monoxide (CO) and hydrogen (H_2), which are combustible gases. A subsequent add process removes the sulfur from the gas stream and converts the reactants to hydrogen sulfide, which is easily removed. Gasification provides a clean, combustible gas, referred to as "syngas," that is nearly sulfur-free.

One of the most efficient coal combustion systems is a combined cycle plant, which uses a combustion turbine as the topping cycle and a steam cycle plant as the bottoming cycle, with a gasifier as the fuel processor. The 100-MW Coolwater plant, near Barstow, California, has successfully demonstrated this design using an oxygen-blown gasifier. Compared to an air-blown gasifier, the Btu content of syngas from an oxygen-blown gasifier is higher.

A combined cycle plant like Coolwater Could be developed in stages. The first phase would be a combustion turbine, initially using natural gas or distillate oil as the fuel source. Phase two would add a steam cycle plant to take advantage of the exhaust heat from the gas turbine to generate steam for a steam turbine. Lastly, a gasification plant could be added and syngas from coal would become the final energy source.

Operating Characteristics and Capacity Contributions

Like conventional coal-fired generators, advanced design coal plants are designed as baseload power generators, with optimum performance at design load. These plants are most likely available to meet capacity and energy loads for about 11 months per year. For approximately 1 month per year, these projects are down for maintenance. They are not designed for short-term peaking operation. The thermal inertia of getting boilers, turbines, and condenser up to operating temperature inhibits quick response to variations in load. Equivalent availability factors, in percent, range from the mid 70s to the high 80s, and capacity factors generally exceed 65 percent. Capacity factors are assumed to equal equivalent availabilities for planning purposes. Fluidized bed designs have capacity factors that range from 9,800 to 10,300 Btu/kWh (9,885 Btu/kWh is assumed for this study). Coal gasification plants have heat rates under 9,500 Btu/kWh (9,270 Btu/kWh is assumed for this study).

Advanced design coal plants, like their conventional counterparts, offer little dispatchability and only a mediocre match to natural load. They are probably only slightly better than nuclear, cogeneration, or geothermal plants in contributing to capacity due to their slightly greater dispatchability.

Costs

Cost estimates for AFBC and integrated gasification combined cycle (IGCC) systems are shown in Tables 3-32 and 3-33. These plants are assumed to be located at the same surrogate sites as the conventional plants. (See Table 3-29).

Fuel cost remains the same. The only change is in the capital and O&M costs.

Table 3-32 Costs - Atmospheric Fluidized Bed Combustion (AFBC) Coal Plant (1988$)

Cost	AFBC-1	AFBC-2	AFBC-3	AFBC-4	AFBC-5
Capital Cost ($/kW)	2,202	1,908	1,899	2,162	1,863
O&M Cost					
Fixed ($/kW-yr)	37.10	37.10	37.10	37.10	37.10
Variable (mills/kWh)	4.8	4.8	4.8	4.8	4.8
Fuel Cost ($/MMBtu)	0.48	1.24	1.39	1.29	1.61
Real Levelized Costs (mills/kWh)	43	47	48	51	51
Nominal Levelized Costs (mills/kWh)	85	93	95	100	100

Table 3-33 Costs - Integrated Gasified Combined Cycle (IGCC) Coal (1988$)

Cost	IGCC-1	IGCC-2	IGCC-3	IGCC-4	IGCC-5
Capital Cost ($/kW)	2,570	2,276	2,267	2,539	2,231
O&M Cost					
Fixed ($/kW-yr)	52.32	52.32	52.32	52.32	52.32
Variable (mills/kWh)	0.8	0.8	0.8	0.8	0.8

Fuel Cost	0.48	1.24	1.39	1.29	1.61

($/MMBtu) (a)					
Real Levelized Cost (mills/kWh)	41	47	49	49	51
Nominal Levelized Costs (mills/kWh)	81	93	97	97	100

(a) Fuel costs reflect transportation to the plant site.

Environmental Effects and Mitigation

Because of the combustion characteristics of fluidized bed and gasifier systems, NOx and SOx emissions are dramatically reduced compared to conventional coal-fired plants (Figure 3-10). However, European experience with fluidized bed combustion suggests that these systems may actually produce higher NOx concentrations than conventional coal plants. Studies are underway to investigate this concern.

Figure 3-11
Environmental Effects and Mitigation - High Technology Coal

Figure (Page E79 Environmental Effects and Mitigation - High Technology Coal)

Other pollutants and emissions from advanced coal systems are similar to conventional coal. Mining, transportation, fuel handling, ash disposal, and cooling water problems are similar for both conventional and advanced coal technologies.

Tables 3-34 and 3-35 present the potential annual environmental impacts per megawatt per year of generation for the AFBC and the IGCC systems, respectively.

Table 3-34 Potential Annual Environmental Impacts Per Average Megawatt of Energy Generation Per Year of Generation for the Atmospheric Fluidized Bed Coal Fuel Cycle (a)

Potential Impacts	Mining and	Transportation	Generation

Air Pollutants
Sulfur Oxides (tons) 0.007 0.109
3.46 (e)
Oxides of Nitrogen (tons) 0.105 0.095
5.8 (e)
Particulates (tons) 0.005 3.05
0.65 (e)
Carbon Dioxide (tons)
8875.74
Carbon Monoxide (tons) 0.021 0.142
1.54 (f)
Fugitive Dust (tons) 0.015 9.46
Heavy Metals and other
1.13
trace elements (lbs)
Radium 226 (curies)
0.000006
Methane (tons)
7.01 (f)

Water Quality Impacts
Consumption (acre ft)
16.43
Oil and Grease (tons)
0.03
Total Suspended Solids
0.06
(tons)
Chloride (tons)
0.06
Iron (tons)
0.00002
Copper (tons)
0.00002
General Discharge (acre ft) 0.182 (b) (alkaline)

Thermal Discharge
42,000
(MMBtu)

Land Effects (c)
Acreage Requirements 0.228
1.58 per MW capacity
Permanent change in
adjusted for capacity
landscape
factor
Solid Wastes 1,766 tons
768
Boiler Bottom Ash
Boiler Fly Ash
Scrubber Sludge
Employment
Construction (employee-
5.1
years per MW capacity)

Operations (employees per MW capacity)	0.178	0.467	0.7
Occupational Safety and Health (d)			
O&M Injuries	14.5x10E(-7) to 2.1x10E(-6)		6x10E(-7) to 2x10E(-6)
O&M Deaths	2.7x10E(-6) to 4.7x10E(-8)		1.3x10E(-9) to 4.5x10E(-8)
Construction Injuries		9x10E(-8) to 2.6x10E(-8)	1.7x10E(-6) to 22.4x10E(-6)
Construction Deaths		1x10E(-9) to 4x10E(-9)	3x10E(-10) to 5.82x10E(-8)

Footnotes, Table 3-34:

(a) Unless otherwise indicated, these generic estimates are adapted from: U.S. DOE. 1983. Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors. DOE/EP-0093. Washington, DC.

(b) Adapted from Argonne National Laboratory. 1988. Energy Technologies and the Enrironment. DOE/EH-0077U. U.S. Department of Energy, Washington, DC.

(c) See sources and calculations in Appendix F to this eis. Ninety-five percent capacity factor assumed.

(d) Adapted from Arthur D. Little. 1985. Analysis of Routine Occupational Risks Associated with Selected Electrical Energy Systems. ea-4020. Electric Power Research Institute, Palo Alto, California. Taken from estimates for a pulverized coal plant.

(e) From BPA's emission estimates for environmental costs and planning.

(f) Adapted from Northwest Power Planning Council. 1991. Northwest Conservation and Electric Power Plan, Volume II, Part II, Portland, Oregon.

Table 3-35 Potential Annual Environmental Impacts Per Average Megawatt of Energy Generation Per Year of Generation for the IGCC Coal Fuel Cycle (a)

Potential Impacts	Mining and	Transportation	Generation
Air Pollutants			
Sulfur Oxides (tons)	0.006	0.10	1.62 (e)
Oxides of Nitrogen (tons)	0.097	0.089	4.26 (e)
Particulates (tons)	0.005	3.2	0.27 (e)
Carbon Dioxide (tons)			8323.53 (e)
Carbon Monoxide (tons)	0.02	0.132	0.15 (f)
Fugitive Dust (tons)	0.014	8.84	
Methane (tons)			7.01 (g)
Water Quality Impacts			
Consumption (acre ft)			16.26 (g)
Oil and Grease (tons)			0.034
Total Suspended Solids (tons)			0.06
Chloride (tons)			0.06
Iron (tons)			0.00002
Copper (tons)			0.00002
General Discharge (acre ft)	0.17 (b) (alkaline)		
Thermal Discharge (MMBtu)			42,000
Land Effects (c)			
Acreage Requirements	0.21 per year Permanent change in landscape		0.75 per MW capacity corrected for capacity factor
Waste Streams			
Solid Wastes	1,649 tons		481.8g
Employment (c)			
Construction (employee-years per MW capacity)			5.7

Operations (employees per MW capacity)	0.166	0.438	0.9
Occupational Safety and Health (d)			
O&M Injuries	14.5x10E(-7) to 2.1x10E(-6)		6x10E(-7) to 2x10E(-6)
O&M Deaths	2.7x10E(-8) to 4.7x10E(-8)		1.3x10E(-9) to 4.5x10E(-8)
Construction Injuries		9x10E(-8) to 2.6x10E(-8)	17x10E(-6) to 22.4x10(-6)
Construction Deaths		1x10E(-9) to 4x10E(-9)	3x10E(-10) to 5.82x10E(-8)

(a) Unless otherwise indicated, these generic estimates are adapted from: U.S. DOE. 1983. Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors. DOE/EP-0093. Washington, DC.
(b) Adapted from Argonne National Laboratory. 1988. Energy Technologies and the Environment. DOE/EH-0077U. U.S. Department of Energy, Washington, DC.
(c) See sources and calculations in Appendix F to this eis.
(d) Adapted from Arthur D. Little. 1985. Analysis of Routine Occupational Risks Associated with Selected Electrical Energy Systems. ea-4020. Electric Power Research Institute, Palo Alto, California. Taken from estimates for a pulverized coal plant.
(e) From BPA's emission estimates for environmental costs and planning.
(f) Adapted from Northwest Power Planning Council. 1991. Northwest Conservation and Electric Power Plan, Volume II, Part II, Portland, Oregon.
(g) Adapted from Ottinger R.L., D.R. Wooley, N.A. Robinson, D.R. Hodas, and S.E. Babb. 1990. Environmental Costs of Electricity. Oceana Publications, Inc. New York.

Supply Forecast

The potential supply of advanced coal technologies is assumed to be the same as conventional coal facilities. This limit is based on a qualitative assessment of the constraints surrounding the development of the coal resource.

The limit is assumed to be 1,800 aMW at the Colstrip site, and 750 aMW at the remaining sites. The total 4,800 aMW potential (1200 aMW for BPA's assumed share) is considered the limit for all coal resources. Any combination of coal technologies could be used within this limit.

3.3 Other Means of Meeting Load

3.3.1 Fuel Switching

Fuel switching occurs when consumers change from electricity to another fuel, usually natural gas, for an energy end use. BPA has begun work to develop a policy regarding what role, if any, BPA should play in influencing the end-use fuel choices of consumers. In January 1992 BPA published an initial technical study of fuel switching potential in the Draft 1992 Resource Program Technical Report Some Northwest utilities are implementing or considering fuel switching programs to help meet their loads. This eis requires analysis of options that may be viewed as resources in the future. Consequently, fuel switching is included as a potential resource in this eis.

The data and analysis presented here are preliminary only. It is important to note that the results are based on the assumption of strong load growth. This fuel switching analysis examines the case where homeowners substitute natural gas for electricity for residential space and water heating. Switching to gas reduces both peak loads and overall energy requirements for electricity. Although many new-home owners are already selecting gas, there is a potential for conversion of electric space and water heat in existing homes to gas. There is also a potential to expand the gas distribution system to reach homes that currently do not have access to gas. This analysis looks at residential fuel switching potential beyond what is expected to occur through market forces driven by the generally lower cost of heating with gas.

Industrial and commercial sectors were excluded from the preliminary analysis. Fuel choice in these sectors is specific to site, equipment, and process. Complex economic and engineering issues and data inadequacy make these market segments difficult to analyze. Exclusion of commercial and industrial fuel switching from the analysis does not mean that cost-effective fuel switching could not be achieved in these sectors. It means only that the residential sector was believed to be more amenable to a screening analysis and more likely to provide near-term fuel switching potential. BPA and others in the region are likely to investigate commercial and industrial fuel switching potential in the future through pilot studies or technical analyses.

Cost

In general, the cost of fuel switching is the difference between installing and operating new gas equipment and operating and maintaining electric equipment. The major cost categories are equipment, administrative, hook-up, and operating. Equipment, administrative, and hook-up are collectively referred to as capital costs. Equipment costs include the space and/or water heating equipment, including flues, venting, piping, and any required code improvements. Administrative costs represent program design, implementation, and oversight costs. These costs are set equal to 20 percent of equipment costs, which is roughly equal to BPA's experience with conservation programs. Hook-up costs are the costs of gas service drop and/or main extension and the metering equipment and installation. Operating costs are the fuel costs associated with operating the space or water heating equipment.

Table 3-36 details projected costs and aMW savings that could be achieved through available fuel switching options.

Table 3-36 Fuel Switching Estimates - 2010

Market Segments	Participating Households (A)	Annual kWh Per Household (B)	Capital Cost per Household (1988$) (C)	Total Savings (Annual aMW) (1988$) (A*B)	Total Capital Cost ($M) (1988$) (A*C)

Existing CFA+WH/SD	34,574	18,300	3,840	72	133
Existing CFA+WH/ME	26,507	18,300	4,920	55	130
Existing Zonal+WH/ SD	46,452	15,100	6,840	80	318
Existing Zonal+WH/ME	35,613	15,100	7,920	61	282
Existing WH Only/SD	137,321	4,500	1,320	71	181
Existing WH Only/ME	105,279	4,500	2,400	54	253
New, all space heat+WH	154,000	10,000	3,654	176	563
TOTAL	539,746			569	1,860

Existing = Existing homes WH = Water Heat CFA = Central Forced Air space heat
ME = Main Extension New = New homes D = Service Drop Zonal = Zonal space heat

Environmental Effects and Mitigation

Fuel switching may create some relatively low impacts to air quality. Impacts to other aspects of the physical environment, water, land use, and wildlife, are all negligible.

Supply Forecast

Estimates of the potential for fuel switching by market segment (see Table 3-36) were based on load forecast information combined with information on natural gas availability. Based on the aggressive policy assumptions and strong load growth required by this eis, a potential of approximately 550 aMW was estimated to be available to BPA by 2010.

3.3.2 Energy Imports

Characteristics and Capacity Effects

BPA is exploring opportunities to serve its future deficits with interregional transactions. Both California and Western Canada have significant potential to provide energy and capacity to the Pacific Northwest: California because of its large system and load patterns which complement Pacific Northwest loads; Canada because of the extent of its gas, coal, and hydro resources. Imports from the Midwest are constrained by the capacity of the existing transmission system and the high cost, both direct and environmental, of new transmission.

BPA could purchase options on winter energy and capacity from California utilities. BPA would normally displace these purchases with nonfirm or spot purchases and/or other short-term purchases whenever economical. Firm energy and capacity options could be used as firm resources for BPA planning and may well provide a cost-effective way to cover at least part of future deficits. An impediment to these transactions is the limited supply of natural gas for electrical utility generation in California in the winter, when residential and commercial demand for gas in the Pacific Northwest is high. Fuel oil can be stored as a backup fuel supply, but this is generally more expensive, and additional fuel storage facilities could be required. The gas supply problem is likely to diminish as new pipeline capacity into California, which is currently under construction or near completion, comes on-line.

Another way of meeting BPA's winter power needs through extraregional transactions would be to enter into joint generating or conservation projects. These projects could provide winter energy and/or capacity to BPA, while providing summer capacity and/or energy to California. Various arrangements need to be explored, including, for instance, joint ownership, where BPA would control the output of the resource in the winter and a California utility would control it in the summer. From the West Coast perspective, capacity is more valuable in summer than winter due to the high value placed on it by California. The addition of nonpower constraints from the System Operation Review (SOR) and Endangered Species Act (ESA) studies could modify this. The value of nonfirm energy also varies over a wide range throughout the year depending on the amount.

Both the Pacific Northwest and British Columbia may have excess capacity available in the summer, which could be used to defer capacity additions that would otherwise be needed to serve growing Pacific Southwest summertime capacity needs. At the same time, Pacific Southwest utilities appear to have the ability to produce firm fossil-fuel-powered energy in the late fall and winter, which could be used to defer new firm energy resources that would otherwise be needed to serve growing Pacific Northwest and Canadian wintertime firm energy needs. These strategies may offer environmental benefits to both anadromous fish in the Pacific Northwest and to air quality in the Pacific Southwest.

The contribution of energy imports to system capacity depends upon the provisions of each contract. BC Hydro may be able to provide energy to the region on-peak, which would make a very good contribution to capacity during the months covered by the contract. California entities are more able to deliver energy off-peak, which would be a depletion of capacity. Nighttime import contracts would be deleterious for capacity. They might provide BPA with the option of declining the energy in the event of nighttime minimum load problems, though the energy foregone by such a choice may have been counted on to meet firm load and would have to be replaced.

Costs

Supplies of imports from the Pacific Southwest were assumed to cost 34.4 mills per kWh (levelized 1988$). Pacific Southwest imports were also assumed to be shaped into the fall-winter period and surplus to the needs of Pacific Southwest systems during that time. As a result, costs do not include embedded system costs, but were based on variable costs.

Canadian imports were assumed to be from Western Canada at a cost of 37.8 mills per kWh (levelized 1988$). These imports were assumed to be built expressly to serve Pacific Northwest loads and full costs are assumed to be covered by BPA. The small difference in costs is due to low fuel costs in Canada and high efficiencies of all-new plants assumed to be built there. For modeling purposes, imports were assumed to use natural gas as fuel. However, actual future transactions may involve any of the other resources described in this eis, particularly cogeneration, hydropower, and conservation.

Environmental Effects

If future transactions involve different resource types, their impacts would be generically described by resource types included in this document.

Air quality is expected to be the area of most environmental effect. Air quality is a problem in metropolitan areas in California, particularly the Los Angeles basin area. Summer power exports from the Pacific Northwest to California would allow dirtier plants to be displaced and could therefore improve air quality in their problem season. Winter generation to return energy to the Pacific Northwest, however, would increase emissions when the plants were operated. The net effect would likely be to improve air quality overall in sensitive areas, but it is likely that the tradeoffs would receive wide public scrutiny before such transactions became routine.

Supply Forecast

For this ElS, import resource supplies available to BPA were assumed to be 1,500 aMW from the Pacific Southwest and 1,500 aMW from Western Canada. For the Pacific Southwest, two-thirds of these resources are assumed to be newly built gas-fired CTs and one-third of the imports are expected to come from existing facilities. The imports from Canada are all expected to come from new gas-fired CTs. The energy resource potential in both the Pacific Southwest and Western Canada may be significantly greater than the 3,000 aMW assumed for this ElS, but actual effects would be specific to resource type, not source.

3.3.3 Efficiency Improvements Technical Description

Hydropower efficiency improvements consist mainly of electronic 3-D cam installation on existing Kaplan hydropower turbines. These savings estimates were first described in 1985 (Generating Resource Supply Curves, DOE/BP/473, July 1985). Most of the turbines that could be modified are located at Corps of Engineers and Bureau of Reclamation projects. These improvements allow the turbines to maintain optimum output by automatically adjusting blade and wicket gate position through a variety of operating heads.

Improving the Federal transmission system consists of reducing the power losses inherent in power transmission. See section 3.3.5 for a detailed technical description.

Operating Characteristics and Capacity Contribution

Efficiency improvements have the same characteristics as the resource they affect. Generation improvements simply increase the output in the same shape as the original hydroelectric resource. Transmission and distribution improvements

are a function of line loadings and other factors that are difficult to project. Consequently, output of this resource is assumed to be flat.

The contribution of efficiency improvements to capacity depends on the nature of the load or resource being made more efficient. Hydro efficiencies would generally allow more generation on-peak with the same amount of water, and would increase capacity.

Costs

Hydroelectric efficiency improvements are estimated to cost less than 3 mills real (6 mills nominal). Transmission efficiency improvements are estimated to cost less than 12 mills real (24 mills nominal).

Environmental Effects and Mitigation

Efficiency improvements improve the efficiency of existing facilities. They are not known to have detrimental environmental consequences.

Supply Forecast

Hydroelectric system improvements available to BPA are projected to be 100 aMW. Federal transmission system improvements are estimated at 34 aMW.

3.3.4 Load Management Technical Description

Demand-side management means planning and implementing activities designed to influence consumer use (demand) of electricity in ways that support meeting that load in a least-cost manner. Demand-side options can be used to support all utility system requirements for satisfying loads. The demand-side options should be compared on an equal basis with other options--combustion turbines, cogeneration, and others.

BPA has traditionally pursued conservation as the demand-side option of choice to help meet loads. The possibility of more stringent hydro system regulations, which could affect the availability of generation to meet loads (see Appendix E), has prompted BPA to begin evaluating other demand-side options.

Following are the demand-side options available to BPA:

Conservation. This is the option with which the Pacific Northwest is most experienced. Conservation is typically pursued when the utility system is deficient in meeting loads in general, e.g., during all or most months and hours of the day.

Load Shifting. This is typically referred to as load management. It is used when there is a problem meeting loads during certain hours, generally peak hours, and when loads during off-peak hours are not a problem. Load management is used to shift load from peak hours to off-peak hours.

Rate Design. A marginal-cost-based rate design which sends price signals to wholesale and retail customers and could potentially reduce load growth and "shape" loads to be more consistent with marginal costs.

Peak Clipping. This is frequently thought of as curtailment. Peak clipping is typically used when there is a problem meeting loads during peak hours and there is no interest in shifting use to off-peak hours.

Flexibility. This is a concept that is used if the system requirements are dynamic and largely unpredictable. Flexibility can be implemented only if consumers are willing to respond immediately to signals from the utility.

Operating Characteristics and Capacity Contribution

The potential contribution to capacity from load management is substantial. In thermal-based systems in other parts of the U.S., load management is one of the most important ways to manage peak capacity deficits. Load shifting to decrease daytime load and increase nighttime load, whether induced by rate design or other

measures, has the potential to increase the regional capacity supply significantly, though the region has little experience with the costs of such an increase.

Environmental Consequences

Demand-side options are viewed as being environmentally benign. They, in fact, can be turned to when more environmentally destructive generating options need to be displaced.

3.3.5 Customer System Efficiency Improvements

A portion of electric power is lost as it is distributed along power lines. As the load supplied by a system grows and changes character, a system that was once properly sized for economic operation becomes undersized, resulting in ever-increasing power losses. Power losses are significant because the utility has purchased the power but lost it without being able to sell it to the ultimate user. Also, the supplier must generate this power, providing the kilowatt-hours lost and the peak capacity to generate these kilowatts, along with the line capacity to transmit the power. When losses are reduced, the energy saved is available for consumers, and the total sales of power can increase without needing to generate additional power.

In the Northwest, total transmission and distribution losses are estimated to be 1,300 aMW per year. Losses for BPA customers range from as low as 2 percent, to as high as 22 percent, with the typical utility experiencing losses averaging around 8 percent. If maximum losses could be held at 5 percent, the potential savings in energy available are estimated to be 2.7 billion kWh annually. Over the last decade, BPA has gathered substantial data on losses in the Northwest and the potential for conservation of lost energy through implementation of customer system efficiency improvements (CSEIs). Research has shown a significant number of CSEIs to be well-established and cost-effective energy saving techniques for utilities.

The two principal sources of losses on a customer distribution system are the primary conductors and the service transformers. Conductor losses occur primarily because of the resistance of the conducting material (aluminum and copper) to the flow of electric current. Usually, the smaller the diameter of the conductor, the greater the resistance to the flow of electrical current. When distribution systems are designed and built, an attempt is made to achieve an economic balance between the cost of larger conductors and the cost of anticipated losses that would occur with the use of smaller conductors. The most economic size for a conductor is one that exhibits the lowest total cost.

With transformers, which change the voltage of the primary system to a voltage that can be used by the customer, losses are classified as either core (no-load) or coil (load) losses. Core losses occur continuously, independent of the load, while coil losses are dependent on the load. In both cases, the loss represents the energy lost as heat during the voltage/current transformation process. Heat reduces both the life and load-carrying capability of all transformers.

Transformer core losses amount to approximately 1.4 percent of the electricity generated on a utility system. Transformers are generally selected so that initial loadings are equal to a given percentage of their nameplate rating. As customers use more power, the transformer becomes more heavily loaded and losses increase.

Seven practical methods can be used to reduce losses associated with transformers and conductors:

1. Substitute larger conductors for smaller ones. This results in lower losses for the same amount of power transmitted. Losses are proportional to peak load

squared, multiplied by resistance. Larger conductors with lower resistance reduce losses proportionally.

2. Increase system voltage, which usually requires installing insulators or transformers, or adding one or more substations. This results in fewer losses, since doubling the voltage reduces the loss to one-quarter of the original value. Losses are inversely proportional to the square of the voltage.

3. Use efficient transformers in place of less efficient transformers. This lowers losses significantly. High-efficiency transformers, such as amorphous core transformers, offer a 60 to 70 percent reduction in the energy consumed by no-load losses in distribution transformer cores.

4. Improve power factors by adding shunt capacitors. This is a cost-effective and simple way to improve power factor and thus reduce active and reactive losses. Essentially, an electric power device that supplies the reactive, magnetized power required by reactive loads, shunt capacitors remove the reactive power from the distribution system, which in turn unloads the distribution lines, releases electrical system capacity, and cuts power bills. An improved power factor also

increases voltage levels, which results in greater distribution efficiency and reduced transformer losses.

5. Add or balance phases. Single phase and two-phase lines have greater losses than balanced three-phase lines.

6. Add parallel feeders. This is a special type of reconductoring in which a heavily loaded feeder is split at a breakpoint some distance from the substation. The breakpoint is chosen to either split the load in half or to supply a large spot load. Losses are reduced as the remote load is carried on a new, large conductor instead of the smaller old conductor.

7. Conservation Voltage Reduction (CVR), which involves regulating distribution voltages to reduce voltage to the consumer, is another CSEI option available to utilities with an appropriate distribution system configuration and load mix. Utilities have found CVR to be both a cost-effective conservation measure and an effective means of reducing peak load and maintaining better distribution system control.

One study sponsored by BPA estimated that approximately 380 aMW could be saved cost effectively on the Northwest systems through reconductoring, transformer replacement, and upgrading the distribution voltage from 12.5 to 34.5 kV. Additional savings of 270 aMW could be achieved through the implementation of CVR.

Environmental Effects and Mitigation

The following list of potential environmental effects parallels the list of seven customer system efficiency improvements provided above.

1. Substituting larger conductors for smaller ones would have negligible environmental impacts. Most potentially significant is a probable change in the electromagnetic field (EMF) produced by the power line. Reducing line losses would probably have little effect on EMF strength. Although the evidence is uncertain, human exposure to EMF is a public health issue. (See the Environmental Effects and Mitigation discussion in Section 3.5, Transmission, for more information on this issue.) Heavy equipment used to change conductors would cause local, temporary impacts (such as operating noise and slight vegetation damage) similar to the impacts of operating heavy equipment for maintenance.

2. Increasing system voltage would affect only previously developed substation facilities, and would therefore not affect the natural environment.
3. Replacing less efficient transformers with more efficient transformers would usually have no effect outside existing substations, so long as old transformers are retired and disposed of properly. In some cases, however, it may be best to replace an old substation with a new substation. This would cause land use impacts at the new substation site that would require site-specific environmental review. Retired transformers should be tested and disposed of in accordance with Environmental Protection Agency and state regulations.
4. Improving power factors by adding shunt capacitors would have no effect outside existing substations.
5. Adding or balancing phases would probably change the EMF characteristics of the line; see discussion under (1), above. This would also cause a negligible change in the appearance of the line, including support structures (poles and crossarms), and minor impacts from heavy equipment operation.
6. Adding parallel feeders might change the EMF characteristics of the line; see discussion under (1), above. If new support structures are needed, construction impacts could also occur, and might require site-specific environmental review.
7. Conservation Voltage Reduction may have negligible effects on EMF characteristics, but would have no construction impacts.

3.4 Emerging Technologies

3.4.1 Fuel Cells Technical Description

Fuel cells are similar to batteries; they convert the energy released in chemical reactions into electricity. Electric current passes between anode and cathode, with hydrogen gas oxidized at the anode and oxygen gas reduced at the cathode, and an electrolyte solution in between. Although one cell produces less than 1 volt, current densities in fuel cells are quite high, on the order of hundreds of amperes per square foot of electrode area. These densities are possible when groups of cells are formed into stacks to provide high power levels.

There are three major types of fuel cells under development, named for the type of electrolyte used: phosphoric acid, molten carbonate, and solid oxide. Aside from different electrolytes, a key distinction among these three cell types is their different operating temperatures. Phosphoric acid cells operate at 400oF, molten carbonate cells at 1,200oF, and solid oxide cells at 1,800oF. Waste heat energy from the chemical reactions can be used as a heat source for steam or in low-temperature bottoming cycle cogeneration. Fuel cells operate at a constant temperature and pressure, regardless of load.

Fuel cell power plants have a fuel processing system and three subsystems: a fuel stack subsystem, a power conditioning subsystem, and a balance of plant subsystem. A fuel processing system may convert natural gas or petroleum distillate into a fuel rich in hydrogen to supply the cathode. Ultimately, coal gasification may be used to generate this fuel, but catalytic reforming is the commercial process currently employed. The fuel stack subsystems generate DC electricity while removing the CO_2 and H_2O byproducts. The power conditioning subsystem converts DC to AC current and also modulates the fuel cell's power factor. The balance of plant subsystem has the controls, water and heat management, cooling, and heat recovery.

Conversion efficiencies, in theory, are near 80 percent, but in practice are reduced to about 60 percent because of parasitic losses, especially electrical

resistance. Since fuel cells are a direct conversion technology, they do not suffer the efficiency penalties of other electric generation technologies, such as steam and gas turbines, that convert heat energy into electrical energy.

Operating Characteristics and Capacity Contribution

Fuel cells have excellent load-following ability; they can adjust output quickly and over a broad range. If an adequate fuel supply is available, fuel cells can also provide baseload service. Projected availabilities should be greater than 90 percent.

Costs

The projected capital cost for fuel cells is $1,300 per kW. Fixed operation and maintenance cost is estimated to be $5.43 per kW per year, and variable operation and maintenance cost is 9 mills per kWh. Levelized energy costs, given current natural gas prices, would be 54 mills per kWh (real) and 83 mills per kWh (nominal). These estimates are based on forecasted operation. Fuel cells have not yet achieved these cost levels.

Environmental Characteristics

For the most part, environmental impacts of fuel cells are related primarily to the fuel type used to provide the hydrogen for the electrochemical reaction. If gasified coal is the source, sulfur removal at the gasification site will be a significant environmental concern. Waste products, including ash and contaminated effluent from gasifier cooling systems, must be treated. If water cooling systems are used to remove heat

from the fuel cells, there may be some thermal pollution where the cooling water is discharged.

Supply Forecast

Although simple and compact, fuel cells have not yet reached commercial maturity. Unproven reliability and durability of the fuel cell stacks themselves, as well as relatively high manufacturing costs, have slowed commercial implementation. Therefore, fuel cells are not considered to be available for planning purposes.

3.4.2 Hydrogen Technical Description

Hydrogen gas is a highly combustible, but environmentally acceptable fuel. Decomposing water through electrolysis is the principal means of producing hydrogen. If there were enough off-peak or surplus power available, hydroelectric energy could be used to produce hydrogen. This fuel could be used later in a combustion turbine, fuel cell, or internal combustion engine to generate electricity during peak periods.

An electrolyzer cell consists of an electrolyte, electrodes, a water porous separator, and a container. In electrolysis, a direct current is passed between two electrodes immersed in a water-based electrolyte. Water molecules dissociate into hydrogen and hydroxyl (H^+ and OH^-) ions. The hydrogen ions migrate toward the cathode and form H_2 gas while the OH^- ions migrate toward the anode. At the anode, the hydroxyl ions decompose to O_2, giving up their hydrogen atoms to other hydroxyls which form water.

The anode and cathode electrodes are usually catalytic metals that help accelerate the reactions and therefore are a critical factor in effective electrolysis. The electrolyte is also critical because it should not react with the hydrogen and hydroxyl ions, not decompose under the voltages induced in the cell, be chemically stable, and resist pH changes. For most practical applications sulfuric acid, H_2SO_4, meets all these criteria.

Electrolysis conversion efficiency is determined by the amount of kilowatt-hours used in electrolysis compared to the heating value (in Btu) of the hydrogen fuel. Since electrolysis is the reverse of the hydrogen combustion reaction, the theoretical maximum heating value of hydrogen would exactly equal the kilowatt-hours of electrical energy used in the electrolysis. However, parasitic loads--mainly for pumps to circulate cooling fluid, electrolyte, and gas products--account for about 5 percent of the total system energy. The rest is the electric power used in electrolysis. Even some of the resistance heat in the cell helps induce the electrolysis reaction.

There is a net energy loss in producing hydrogen as fuel then generating electricity compared to direct hydroelectric conversion. First, the electrolysis conversion efficiency is about 80 percent; then converting the energy in hydrogen gas into electricity carries an additional penalty. Per kilowatt-hour, the electrical energy produced from a combustion turbine or fuel cell using hydrogen fuel would be about 15 to 30 percent that produced directly from a hydroelectric turbine.

Reliable technologies for electrolizing, storing, and using hydrogen exist. The principal technical obstacle in using hydrogen for peak power is to understand the adequacy of reservoirs where the hydrogen might be stored. Underground natural gas reservoirs might be an option. Compared to natural gas, hydrogen has about one-third the energy content per cubic foot so would take about three times the storage volume required by natural gas. Two Northwest sites--Jackson Prairie,

Washington and Mist, Oregon--have been identified as possible hydrogen storage reservoirs.

Pipeline or transport arrangements would be needed to move the hydrogen from storage to a combustion turbine for peak load generation. However, electrolysis generation of hydrogen only makes sense when there is surplus hydropower and the overall conversion efficiency of storing hydrogen fuel and regenerating electricity with it is economical.

Operating Characteristics and Capacity Contribution

Hydrogen as a fuel would most likely be used in CTs for peaking power. Fuel cell use of hydrogen is also a possibility. The generation profiles of either of these applications would depend on how CTs or fuel cells are used.

The idea behind hydrogen energy storage would be to produce hydrogen gas during the spring and summer months when the Columbia River system water runs high and electricity demand is low, store the hydrogen, then use it during winter peak periods as a combustion fuel in combustion turbine peaking plants.

Costs

Costs for a hydrogen electrolysis plant were developed from data obtained from the Pacific Northwest Hydrogen Feasibility Study, March 1991, prepared for BPA by Fluor Daniel, Inc. These costs are based on an electrolyzer-fuel cell combination. Capital cost projections are $4,100 per kW; fixed operation and maintenance cost is $8.26 per kW per year; variable operation and maintenance cost is 28 mills per kWh. This would yield a real levelized cost of 158 mills per kWh (242 mills per kWh nominal levelized). These cost levels were calculated assuming an input power cost of 14 mills per kWh.

3.4.3 New Nuclear Fission Technology

The nuclear industry and the Federal Government have, over the past several years, been developing advanced nuclear power plant designs. Objectives of these advanced designs include improved economics, reduction in investment risk, and improved safety. This is to be accomplished by reduced plant size, increased factory fabrication, increased reliance upon "passive" safety systems requiring no operator intervention, general simplification of design, increased safety margins, improved maintainability and improved operator-machine interfaces. Guiding the development of advanced designs is a philosophy of avoiding revolutionary design changes in favor of an evolutionary approach that begins with refinement of current designs.

Advanced Nuclear Plant Designs

Three generations of advanced designs are under development. "Large evolutionary" designs are based on incremental improvements to existing light water reactor designs. These plants are available for overseas order and are expected to be approved for construction in the United States in the early 1990s. "Small evolutionary advanced" designs use current light water reactor technology, but would incorporate significant downsizing and passive safety features. These designs may be available for order by the mid-1990s. "Modular advanced" designs would use non-light water reactor technology and would incorporate extreme downsizing, a high degree of modularity, and passive safety features. Modular advanced designs probably will not be available for order until the turn of the century.

Large Evolutionary Plants

Two U.S. vendors are actively developing large evolutionary advanced designs for the international market and for submittal to the Nuclear Regulatory

Commission for certification. The models and vendors are General Electric's Advanced Boiling Water Reactor (ABWR), and the System 80+ by Combustion

Engineering. These designs are essentially refinements of these vendors' earlier light water reactor designs. They retain the large-scale (1,200 MW capacity) and general engineering features of predecessor designs.

The Advanced Boiling Water Reactor is an evolutionary version of existing General Electric boiling water reactors such as WNP-2. Design of this plant has been underway since 1978, under the auspices of an international consortium of boiling water reactor vendors. The Advanced Boiling Water Reactor is intended to incorporate the best features of the earlier boiling water designs offered by participating vendors. Distinguishing features include a simplified coolant recirculation system, triple-redundant emergency core cooling, improved containment, and improved control and instrumentation systems. Two 1,365-MW units have been ordered by the Tokyo Electric Power company for construction beginning in 1991 at the Kashiwazaki-Kariwa station. Commercial operation of the first unit is scheduled for 1996 and the second unit in 1998.

The Combustion Engineering System 80+ is a refinement of the Combustion Engineering System 80 designs used at Palo Verde 1-3 and at WNP-3. Operating experience at Palo Verde is being used to guide design improvements, as is the experience of Duke Power, one of the more successful U.S. nuclear utilities. The principal design changes involve improvements to the containment building, the emergency core cooling system, a safety depressurization system, increased thermal margins, and improved control room design. The System 80+ is scheduled to be certified by the Nuclear Regulatory Commission in Fiscal Year 1992.

Because they have not yet been built or tested, the cost and performance characteristics of large evolutionary designs remain somewhat speculative.
Because these plants represent refinements of current nuclear technology, actual construction costs are likely to be similar to those of the better plants recently completed.

Small Evolutionary Advanced Plants

The small evolutionary advanced nuclear power plants would represent a major departure from contemporary nuclear power plant design. Though using conventional light water reactor technology, these plants would be considerably smaller than current designs, would use greatly simplified mechanical and electrical systems, and would employ passive safety systems requiring no operator intervention for many hours following an abnormal occurrence. These designs are expected to have greatly improved performance and cost compared with contemporary designs. Performance objectives for small evolutionary designs, prepared by the Electric Power Research Institute, include 87-percent availability, a 4-year construction period, and a 60-year operating life (Stahlkopf, 1988).

Two small evolutionary advanced designs are being developed. The Westinghouse AP-600 would employ conventional pressurized light water technology in a 600-MW plant, featuring overall simplification, a passively actuated and operated emergency core cooling system, and advanced instrumentation and control systems. A 3-year construction schedule is targeted, with a 5-year overall lead time from order to commercial operation. Construction costs are estimated to be $1,270 to $1,500 per kW (Electrical World, 1988; Stahlkopf, et al., 1988). The AP-600 is being developed under a program jointly funded by the Electric Power Research Institute and the U.S. Department of Energy.

The General Electric Small Boiling Water Reactor (SBWR) would be based on conventional boiling light water reactor technology. This plant also would be in the 600-MW size range, and also would employ passively actuated and operated

emergency core cooling. This design also is being developed under the Advanced Light Water Reactor program of the Electric Power Research Institute and the U.S. Department of Energy.

Modular Advanced Plants

Modular advanced reactors would employ alternatives to the conventional light water reactor technologies used in the current generation of commercial nuclear plants to achieve the objectives of improved performance and safety, and lower construction and operating costs. Most of the proposed designs are highly modular, with unit sizes ranging down to the 100 to 200 MW level. These small sizes would permit greater factory fabrication, better quality control, shorter construction lead time and would allow for improved containment of radioactive materials. Several design concepts envision arrays of small reactors operated by a central control room and supplying a common turbine generator to capture some of the economies of scale associated with larger plant sizes.

Examples of this generation of advanced designs include the Asea Brown-Bovari PIUS, the General Atomic Modular High Temperature Gas-Cooled Reactor, and the General Electric PRISM. These designs are currently at the conceptual stage of development. It is not expected that they would be certified for commercial use prior to 2000.

Prospects for New Nuclear Plants in the Pacific Northwest

Three generations of new nuclear power plant designs are presently under development. The most advanced of these (in the sense of schedule) are the so-called large evolutionary advanced plants. These plants are basically refinements of existing models offered by U.S. vendors, and are expected to be certified for U.S. construction by the Nuclear Regulatory commission by the early 1990s. There is little evidence of interest in these plants by any U.S. utility, since they would face many of the development issues faced by conventional light water commercial reactors. Though these plants might be easier to build and achieve better performance, they will retain the large size and active safety systems of current designs. Because of their investment risk, lengthy construction period, and large plant size, the Council has not included these plants in its resource portfolio.

The small evolutionary plant designs would address some of the major development issues associated with nuclear power. Cost uncertainties will likely be reduced and public acceptance might improve because of passive safety systems and improved cost and schedule certainty. Smaller plants, shortened construction time, and greater cost certainty should help alleviate investment risk. These plants might be available for commercial operation in the 2000 to 2002 period.

Finally, modular advanced designs may be certified for construction near the end of the century. These designs would further reduce investment risk by using much smaller unit sizes. Plant safety should be improved, in an absolute sense, by improved containment of radioactive materials and innovative system design. Cost reductions and greater cost certainty should be achieved by using extensive factory fabrication. Commercial units probably will not see service before 2005. There is a possibility that the Northwest might see a demonstration unit using modular advanced technology, because the U.S. Department of Energy is considering construction of a tritium production reactor with this technology at the Idaho National Engineering Laboratory. This plant could come on-line around the end of the century.

None of the advanced designs address the issue of high-level waste disposal. By providing additional on-site spent fuel storage, utilities can prolong

plant operation until such time as a high-level waste repository is developed. Alternatively, the Federal Government or utilities could develop centralized monitored retrievable storage facilities for interim storage of spent fuel.

The more advanced design concepts--small evolutionary advanced plants and modular advanced plants--feature smaller unit sizes, passive safety systems, and other features enhancing their attractiveness. But there is great uncertainty with respect to the time when these plants will be available for construction. Because they are at such an early stage of development, their cost and performance characteristics also are highly uncertain. Current cost and performance estimates appear attractive, but most likely are optimistic design goals and may not be realistic. Because of these uncertainties, advanced nuclear technologies do not appear, at this time, to be reliable and available within the meaning of the Northwest Power Act and therefore are not included in the portfolio.

The Council will continue to monitor new nuclear technologies and reassess them as part of future power plans.

3.4.4 Pumped Storage

Like most utility storage technologies, off-peak energy is used to "charge" or fill a reservoir, which is then discharged during peak demand periods in a cyclic fashion. A typical pumped storage system uses a reversible pump/turbine and a reversible motor/generator. During off-peak charging, the motor drives the pump and delivers water to an elevated reservoir. During peak periods, the water is released and runs back through the reversible pump, which serves as the turbine.

The turbine drives the electric motor in reverse, which works as the generator. A modular energy storage system uses a closed pumped hydro technology. It differs from the traditional pumped storage in that it uses ground water to charge a relatively small closed system, thereby avoiding fish impacts. Since it does not depend on surface water flow, its location is more flexible than traditional hydro or pumped hydro. A typical installation would have a 100 MW capacity (twin 50 MW units) and would cost $700 per kWh (turn-key installation). A disadvantage of any pumped hydro system in the Northwest is that it is a net energy loser. Since the Northwest is an energy deficit region, the loss of energy makes pumped hydro systems an expensive alternative to more traditional ways of acquiring capacity (e.g., combustion turbines). Although there may be specific applications where such facilities make economic sense, such facilities are not generally considered to be a competitive resource.

3.5 Transmission Technical Description

Development of new generation and import energy resources may require construction of new or upgraded transmission facilities to integrate with the existing transmission system, and to ensure continued reliable operation of the regional transmission system. However, until specific information is available on the size, location, and operating characteristics of proposed new resources, collateral transmission system requirements cannot be specifically known. Generally, resources located farther from load centers, especially resources east of BPA's transmission system, would require more transmission facility construction than would resources closer to load centers.

Transmission construction actions could include building new double-circuit extra-high-voltage lines, single-circuit lines, upgrading existing lines, and upgrading existing substations. New lines could be located along existing transmission line corridors, or on new corridors. (See Figure 3-3.) Both the construction and operation of transmission facilities may have environmental effects. These potential environmental effects are described below and will be addressed in detail in subsequent site-specific environmental documents tiered to this eis.

Environmental Effects and Mitigation

Land use impacts are directly related to the amount of new and existing rights-of-way affected. Building a transmission line with a new corridor would have a greater impact to residential, commercial, agricultural, and forest land because new line segments would intrude on existing land use. Agricultural land would be removed from production for tower sites and access roads, and structures could interfere with farming operations. Forest land would be removed from production for the right-of-way, line clearances, and access roads. Transmission lines may cross trails and intrude on scenic views. Many people contend that transmission lines reduce property values. A transmission line using expanded or existing right-of-way would create fewer land use impacts. Construction and maintenance may cause soil erosion. Careful siting, terraces, and other erosion control methods, and restoration can reduce erosion.

Clearing during construction and expanding existing rights-of-way can impact vegetation. Existing vegetation is removed, and vegetation composition may change. Noxious weeds may be introduced. Vegetation communities also are affected by maintenance, especially if herbicides are used. Clearing should be kept at a minimum and disturbed areas should be reseeded.

Floodplains and wetlands may be affected during construction of structures and access roads, and vegetation may be removed. Using existing right-of-way or spanning floodplains and wetlands would decrease potential impacts.

Although the increase would be short-term, clearing new right-of-way, expanding existing right-of-way, and constructing access roads can accelerate run-off and increase sediments in streams. The resulting decrease in water quality could impact fish. Culverts and hand clearing near streams can reduce potential impacts. Herbicides used to control vegetation, and oil used in capacitors at substations could contaminate ground water.

Figure 3-12
POTENTIAL NEW GENERATION AND IMPORT LOCATIONS, AND RELATED TRANSMISSION PATHS

Figure (Page E98 POTENTIAL NEW GENERATION AND IMPORT LOCATIONS, AND RELATED TRANSMISSION PATHS)

Birds may collide with the new line. However, by increasing the amount of edge habitat, species diversity may increase. Clearing may displace some wildlife and alter habitat and increase access for hunters.

Transmission lines may have visual impact. Lines could cross scenic areas, and towers may be out-of-scale with the surrounding landscape. Views would be disrupted for the long term. Careful siting, including avoiding crossings at high points, avoiding long views, placement of lines behind ridges or timber, diagonal approaches, and maximizing the use of natural screens (vegetation or terrain) can reduce visual impacts. Since transmission lines may be a hazard to aircraft, lines and towers are marked. While these markings increase safety, they may not be aesthetic.

Upgrading existing lines, constructing a new corridor, or expanding an existing right-of-way could disturb cultural resources. Construction may disturb subsurface sites, and the line may intrude visually on cultural resources. Archaeological surveys and vegetation screening may reduce impacts.

Construction vehicles create dust and exhaust emissions. Some construction debris is burned. Although these impacts are temporary, air quality may be affected. Construction and maintenance may also create noise.

Electric and magnetic fields and corona are electrical properties of alternating current (AC) transmission lines that may affect plants, animals, and people.

Electric and Magnetic Field Effects. Electric fields induce voltages and currents in conducting objects. When a person or animal insulated from ground touches a grounded object in a strong electric field, a perceptible tingling or an annoying spark discharge may occur. However, if a grounded person were to touch a large conducting object insulated from ground, a painful or harmful discharge shock could be received. For this reason, fences, irrigation systems, antennas, and other large metallic objects near the larger transmission lines are routinely grounded, as required by BPA policy and the National Electric Safety Code. It is also possible that fields from transmission facilities could affect operation of cardiac pacemakers and cause premature detonation of explosives with electric blasting caps, and that spark discharges could ignite flammable mixtures (e.g., gasoline vapor and air). BPA publishes safety information about these possible effects in a free, non-technical booklet, Living and Working Around High-Voltage Power Lines.

Magnetic fields scan also induce voltages in objects near transmission lines, resulting in nuisance shocks. However, techniques are available which BPA uses effectively to mitigate shocks from magnetic field induction.

Although shocks associated with electric and magnetic fields are well understood and largely controllable, questions have been raised as to whether there are long-term health effects from exposure to electric and magnetic fields. These fields induce weak currents and electric fields in people and animals. Although these currents and fields are too small to be felt, other than by hair stimulation, some scientists suggest that long-term exposures to these fields are potentially harmful and should be minimized.

Hundreds of studies have been done throughout the world. Both laboratory and field studies have been done on plants, focusing on growth and yield. Electric and magnetic fields produced by transmission lines do not appear to affect the growth of crops or other low-growing vegetation. Tree branches allowed to grow near conductors can be damaged by induced corona from strong electric fields. However, overall tree growth and survival apparently are not decreased.

Extensive field research has also been done on a variety of animals, including insects, wildlife (birds and mammals), fish, and livestock. Research to date has not shown that electric and magnetic fields have an adverse effect on behavior or health. Although various functional changes (e.g., drops in hormone levels) have been reported in exposed animals, research with laboratory animals has not shown any hazardous effects from exposure to electric or magnetic fields.

Other studies have found that these fields can also cause functional changes in isolated cells and tissues. Some scientists believe that the fields cause effects by interacting directly with cell membranes. Laboratory research to obtain the information needed to assess the biological implications of these reported effects and to understand their causative mechanisms is ongoing.

A growing number of epidemiological studies suggest an association between electric and magnetic fields and cancer. Even though the relative risks reported in these epidemiological studies are low and a cause-and-effect link has not been established, the need for long-term research to resolve this issue is universally acknowledged. Because of the uncertainty, BPA has adopted Interim

Guidance as a precautionary measure. This Interim Guidance was updated in August 1992. When new transmission facilities are designed and located, the potential for long-term field exposure increases is considered a major decision factor. Such increases are avoided if practical alternatives for reducing the exposures exist. This interim guidance will be reassessed as new information becomes available.

Corona Effects. In addition to electric and magnetic field effects, transmission lines produce corona. Corona, the breakdown of air very near conductors, occurs when the electric field is greatly intensified at projections (such as water droplets) on the conductor. Corona is most noticeable in 500-kV and higher voltage AC lines during foul weather. Corona may result in audible noise, radio and television reception interference, light, and production of minute amounts of ozone.

Line designs have been developed that greatly reduce audible noise levels and often corona effects. Few noise complaints are now received from persons living near BPA 500-kV lines. Although radio and television interference sometimes occurs, BPA policy requires all problems to be investigated and corrected if a BPA facility is involved. Studies have shown that the amount of ozone produced is generally not detectable above average background levels.

For additional information on either electric and magnetic field effects or corona effects, please refer to a publication available from BPA titled Electrical and Biological Effects of Transmission Lines: A Review.

3.6 Capacity

Capacity is the ability to produce energy upon demand. The Pacific Northwest, with its huge hydro system, has often been likened to a battery: when the wicket gates open and water is released through the turbines, electricity is generated. Shut the gates and generation ceases. Thermal-based systems build resources just to hold in reserve so they will be available to meet peaks. Many of these are low-capital-cost, high-operating-cost resources that the utilities hope they will never have to run, but which they must have available to meet reserve requirements for peak loads, resource failures, and system reliability.

The Pacific Northwest hydropower system was designed with turbines capable of capturing much more of the potential energy from the rivers than its firm energy capability. Since firm energy capability is defined as worst flow conditions, not average, the system has much more installed capacity than is required to serve its firm loads. Because of the transmission interconnections between the Pacific Northwest and British Columbia, and between the Pacific Northwest and California

and the Inland Southwest, the region can often sell its excess capacity as nonfirm energy, thus reducing the need for purchasing utilities to invest in resources they do not expect to operate. Such sales generate revenues to repay investments in the Federal transmission system, and to minimize BPA's rates consistent with the "prudent business practices" required by its authorizing statutes.

Overall, the west coast electric power system is a summer peaking system, with summer loads exceeding winter loads by a factor of about four. BPA's system, conversely, is largely a winter peaking system, and capacity needed to meet winter loads is underutilized in summer. Except for part of the 1980s, when the entire system was awash with new, baseloaded, and surplus resources, seasonal exchanges in which BPA sold summer capacity in exchange for combinations of capacity, energy, and money have been the norm. As loads in the west coast system have grown, capacity is becoming increasingly valuable, and may provide both increasing revenues to BPA and increased efficiency of the existing west coast system in the period covered by this eis. However, recent changes in hydroelectric system operations to enhance fish survival have reduced the capacity of the Federal system during some months. The future capacity of the Federal system may be affected by decisions about system operations that result from the on-going System Operation Review (SOR) and Endangered Species Act planning.

Development of new resources in the Pacific Northwest may increase potential summer capacity (and energy) sales. Such transactions can have added benefits. Substitution of Pacific Northwest capacity in the summer reduces the adverse effects of generation on the vulnerable airsheds of California's metropolitan areas. When the capacity sold comes from the Pacific Northwest hydropower system, the increased flows associated with generation also speed young anadromous fish on their way to the ocean. Some of these transactions have lately been dubbed "environmental exchanges."

The planning models used in this eis are energy models and do not take into account potential capacity impacts of resource additions. As a result, economic costs and benefits attributable to capacity are not incorporated in the economic analyses presented. A model which does incorporate capacity is being developed for resource planning at BPA, with preliminary estimates indicating that summer capacity sales potential may become a significant economic factor in future resource acquisition decisions.

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Appendix F. Technical Information on Analysis Methods and Results

Appendix F. Part 1. Model Descriptions

SECTION 1: Integrated System for Analysis of Acquisitions (ISAAC) SECTION 2: Accelerated California Market Estimator (ACME) SECTION 3: System Analysis Model (SAM) F1

SECTION 1 INTEGRATED SYSTEM FOR ANALYSIS OF ACQUISITIONS (ISAAC)

Model Description

The ISAAC model is a decision analysis model developed jointly by BPA, the Northwest Power Planning Council (NWPPC), and others in the region to analyze resource acquisition strategies and issues. The ISAAC model simulates the acquisition of resources to meet load growth in the Pacific Northwest. It also simulates the operation of the Pacific Northwest power system over a wide range of uncertainties, including load growth, resource supply, streamflow conditions, fuel prices, and aluminum markets.

The ISAAC model is an energy model that tuns on a monthly or seasonal basis for twenty years or longer. The ISAAC model divides the Pacific Northwest into three parties; Generating Public Utilities (GPU), Investor Owned Utilities (IOU), and Bonneville Power Administration (BPA). The BC Hydro power system operation, the California demand for energy and the Interties that connect these regions are also modeled.

The ISAAC model has a detailed simulation of acquisition planning. In each simulation, the ISAAC model options and acquires generating and conservation resources to meet a planning load forecast and then dispatches the power system to meet the actual load growth. Running many simulations over a wide range of load growth, streamflows, and other uncertainties allows the model to account for the value of many resource characteristics, such as; options, construction lead times, unit size, and dispatchability.

The ISAAC model operates the hydro system as a one dam model. The modeling of the thermal dispatch, California market, and Intertie policies is less complex than other models which are designed to address detailed operational issues. This speeds up the run time and allows one to evaluate a large number of resource acquisition plans.

Inputs to the ISAAC include a distribution of load forecasts, cost and performance characteristics of existing hydro and thermal generating resources, new resource supply curve data (cost, availability, lead times), aluminum industry data (price forecasts and plant capabilities), California market conditions, and extra-regional and intra-regional contracts.

A typical study consists of 100 simulations, each simulation selecting discrete values for the uncertainty variables for a study horizon of twenty years or longer. Results are reported as sample means over all simulations or as frequency distributions. The ISAAC model reports capital costs, system operating costs, and revenues received by each party from extra-regional sales. The model also reports transactions between PNW parties, how often particular resources are acquired and how often those resources are dispatched to serve load. The ISAAC model measures the costs of over-building when loads subsequently fall, or under-building when loads subsequently rise faster than forecast.

Since the System Analysis Model II does not make resource acquisition decisions, it needs as input additional resources to maintain load/resource balance through 2012. The ISAAC model was used to select new conservation and generating resources for the study horizon 1993 to 2012. For planning purposes, it was assumed that BPA and the IOUs will acquire resources separately and that none of the IOU load will be placed on BPA. It was also assumed that all load growth of the GPUs will be placed on BPA.

SECTION 2 ACCELERATED CALIFORNIA MARKET ESTIMATOR (ACME)

Model Description

The ACME is a model developed by BPA that provides estimates of the market in California for nonfirm energy from the Pacific Northwest (PNW). It produces a market curve that relates the quantity of nonfirm energy delivered to California to the variable cost of the resources that nonfirm energy could displace. The ACME considers one week at a time, each week divided into 56 3-hour periods that represent a month. It can produce a market for up to 20 years.

The ACME uses two bubbles to represent California (CAL) and the Inland Southwest (ISW). All entities in California are aggregated together and the states of Nevada, Utah, Arizona and New Mexico in the ISW are aggregated together. Each bubble has its own set of loads and resources. One of the available resources to meet California load represents nonfirm energy from the PNW. The resources in each bubble are dispatched to serve their respective loads. This dispatch takes four stages: hydro dispatch, pre-commitment to determine minimum generation, unit commitment to determine maximum generation, and a thermal dispatch. Next a transfer dispatch takes place that allows energy deliveries from ISW to CAL if the ISW has a cheaper resource to run that could displace a more expensive CAL resource. Finally, the model operates California pumped storage facilities to shift load from heavy-load periods to light-load periods.

Inputs to the ACME include California and Inland Southwest energy load forecasts and load shapes, California and Inland Southwest resource data (minimum and maximum generation factors, heat rates, maintenance, etc.), Intertie connections, gas and oil price forecasts and coal escalation rates.

There are two types of output the ACME produces that represent California's demand for PNW nonfirm energy. The first output file (MARGINAL.DAT) is a demand curve that relates California's marginal costs (in mills/kwh) to the amount of PNW nonfirm energy purchased by California (in 1000 MW increments). This market is produced by increasing the amount of PNW nonfirm energy purchased to displace California generation by 1000 MW increments from 0 to 8000 MW and recording the marginal cost of the last resource running in California. The second output file relates the quantity of

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PNW nonfirm energy purchased by California (in MW) to the price of PNW nonfirm energy (in 1 mill/kwh increments). This `mill-by-mill' output is generated by varying the price, not the amount, of PNW nonfirm energy and recording the amount of PNW nonfirm energy purchased by California.

The ACME model was used to provide a California market for the SAM II for the study horizon 1993 to 2012. The file `MARGINAL.DAT' represents California's potential market for PNW nonfirm energy based solely on California's decremental fuel cost of resources to displace.

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SECTION 3 SYSTEM ANALYSIS MODEL (SAM)

Model Description

The SAM is a Monte Carlo simulation model that was developed by BPA and other Pacific Northwest Utilities to evaluate planning and operating policies of the Pacific Northwest. The model simulates the operation of the Pacific Northwest power system and British Columbia Hydro power system taking into account uncertainties in loads, thermal performance, and streamflow conditions. The SAM includes a complex hydro regulation model that is integrated with thermal resource operation. The SAM is an energy model that operates on a monthly basis for a study horizon up to twenty years.

The SAM II is an option of the SAM that splits the PNW region into three groups; Generating Public Utilities (GPU), Investor-Owned Utilities (IOU), and Bonneville Power Administration (BPA). The SAM II shares much of the same logic as the SAM, but includes planning and operating policies that reflect how the PNW groups interact. The policies that the SAM II accounts for include: the GPU Requirement load, Northwest preference, regular interchange, and Intertie ownership.

The SAM includes regional planning as defined by the Pacific Northwest Coordination Agreement. The purpose of regional planning is to operate the hydro system in a coordinated manner. The model includes a two-year critical period planning process that occurs at the beginning of each operating year. During this annual planning, decisions about shifting and shaping hydro Firm Energy Load Carrying Capability (FELCC) are made. During a period planning process, Prices for loads and dispatch rates for hydro resources are at to simulate the operation of the hydro/thermal system as realistically as possible.

The regional SAM operates the hydro and thermal systems as a one utility owner. Hydro and thermal resources are dispatched to serve load in the most economic manner; the resource with the lowest variable cost serves the load with the greatest value or price. If running the SAM II, an economic dispatch is also performed where each PNW group has the opportunity to serve its own load, serve another group's load, or displace another groups resource based on opportunity costs. The California demand for nonfirm energy is included as a

load. If there is economic surplus energy available in the PNW or Canada, the California market is allocated according to the Long-Term Intertie Access Policy. Surplus BC energy is made available to the US for purchase after BC resources are operated to serve its own load.

After the dispatch is complete, the hydro regulator is called to produce a desired amount of hydro generation. Even though the hydro system is operated as a one utility owner, the model keeps track of project generation by owner. This allows for storage transactions to take place between PNW groups, when running the SAM II option.

The SAM models uncertainty in streamflow conditions. Water years for each operating year are randomly selected from fifty historical water years (1929 - 1978). The SAM reflects variations in load due to weather conditions and economic trends, but does not consider load growth uncertainty. The model accounts for two sources of uncertainty for thermal plants; availability (forced outages) and arrival dates.

Inputs to the model include PNW loads, intra-regional and extra-regional firm contracts, existing and planned thermal plant characteristics and operating costs, hydro plant data, conservation and renewable resources, SC Hydro loads and resources, California market, Intertie ownership, and BPA rates.

The California market input to the SAM consists of California's marginal costs for 563-hour periods for each month for twenty years as a function of PNW nonfirm energy available in 1000 MW blocks. The SAM adjusts the California market to reflect the impact of firm contracts with California. Firm exports reduce and firm imports increase the amount of market for PNW nonfirm energy. Also, since the SAM is a monthly energy model, the hourly market is reduced to a monthly average demand curve.

A typical study consists of 200 simulations, selecting random values for streamflow conditions, loads, and thermal performance. The model provides system costs (production, curtailment) and revenues (economy energy, wheeling) for economic analysis. It also provides resource sac output (thermal plant generation, hydro operation data) for environmental analysis. The hydro data includes reservoir elevations, flows, and overgeneration spill. Results are reported as sample means over all simulations. Some information can be reported as sample means over low, medium and high streamflow conditions.

Modeling of the Northwest Power Planning Council (NWPPC) Phase II Amendments To the Columbia River Basin Fish and Wildlife Program

The SAM was modified to incorporate the Phase II amendments to the NWPPC's Fish & Wildlife Program. The Phase II amendments call for a new water budget operation on the Snake River and an operational water budget on the Columbia River to be used in conjunction with the existing water budget volume.

Appendix F. Part 2. NFP eis Analytical Specification

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Appendix F

Part 2. NFP eis Analytical Specification

OVERVIEW

The purpose of this discussion is to identify the System Analysis Model (SAM) studies for the NFPeis. This appendix contains three major sections. The first section identifies each of the alternatives and their respective assumptions that will be modeled in the SAM. Not all of the alternatives listed in Chapter 2 will be analyzed with the SAM because of model limitations. Those alternatives not covered will be analyzed using a qualitative procedure versus the quantitative SAM based procedure. However, the qualitative analysis may rely on inferences made from the SAM study results. The second section identifies the types of sensitivities that are considered in the environmental process. Accounting for all of the alternatives and the sensitivities results in a large number of required SAM runs. It is prudent to minimize the number of actual SAM runs needed. Therefore, a third section subjects the full range of required SAM studies to a process that logically removes certain studies from consideration.

ALTERNATIVE SPECIFICATION

This section identifies the assumptions contained in each of the NFPeis alternatives analyzed with the SAM. The procedure employed in the NFPeis analysis is defined as one of `comparative statics.' This is a process of comparing the results from two different SAM studies where only one factor has been allowed to change between the studies. The differences in the study results can then be attributed to the impact of the one altered factor.

A basic set of data and assumptions is contained in each of the SAM studies.

This load, resource, and operational information is intended to. represent !he current situation as modeled by the SAM. This basic data is described under the `No Action' alternative and is common to all of the NFPeis alternatives analyzed. The discussion of each alternative identifies data and assumptions that differ from the `No Action' case.

No Action

The No Action case implies that no new decisions will be made concerning use of the Third AC Intertie during the 20 year (September 1992 through August 2012) study horizon. The assumptions in this case are essentially those that

frozen early in the eis process and may not be the most current available. Considerable time is required for updating and verifying the impact of new information in the SAM. Until the SAM studies for the NFPeis were performed, information more current than that included in the SAM was considered in light of whether it would alter the eyed results of the study process. The nature of the `comparative statics' approach implies that certain data modifications common to both studies will not affect the differences between those studies. Items that would alter the differences were incorporated as much as possible and those that didn't were not incorporated. Each of the major data categories and their assumptions are described below.

BC Hydro

BC Hydro load and resource information is based on the 1991 update of their Electricity Plan. The rated transfer capability of the transmission interconnection

with the Northwest is 2300 MW.

Pacific Northwest

Loads

The 1991 Joint Load Forecast provides the individual entity (Investor Owned Utilities - IOU, Generating Publics - GPUB, Non-Generating Publics - NGPUB, and Federal - BPA) load forecasts. This forecast is used in the 1991 Pacific Northwest Loads and Resources Study (Whitebook) and in the 1992 Resource Program. BPA power sales contracts are assumed to be renewed in 2001.

Estraregional imports and exports include all such contracts listed in the 1991 Whitebook. In addition, new contracts not included in the 1991 Whitebook were added. These include Idaho Power to Azusa, Banning, and Colton (assured delivery contracts 7 MW peak, 7 aMW, delivered-year round from 11/1993 thru 9/2010) and Washington Water Power to NCPA (joint venture contract, 50 MW peak, 50 aMW, delivered year round from 11/1993 thru 9/2010).

The NFPeis assumes that the 800 MW of intertie capacity available for assured delivery under the Long Term Intertie Access Policy are fully used. For the NFPeis studies, the 153 MW peak, 122 aMW of unused assured delivery capacity for firm surplus sales was split 52% - 48%, IOU - GPUB, respectively. Generic IOU/GPUB firm sale contracts to the Southwest were created to fill the unused portion of the assured delivery capacity.

Resources

The amount of existing thermal resource in the region is consistent with the 1991 Whitebook. The major difference is that Trojan is removed from service in 1996. Incremental resources required to create a load/resource balance are provided from the ISAAC model. Resource availability and cost information is consistent with the 1992 Resource Program. NFPeis resource additions for high and low loads, by entity (BPA and IOU), are detailed in tables 1 thru 4 at the end of this appendix.

Regional hydro resource capability is based on the 1992 Pacific Northwest Coordination Agreement (PNCA) submittals. It is assumed for the NFPeis that the PNCA will be renewed in 2003. In addition, non-treaty storage with B.C. Hydro is 4.5 million acre-feet and the current agreement is assumed to be renewed in 2003. Hydro system operating guidelines for the Columbia and upper Snake are based on Phase 2 of the Regional Council's plan. Appendix C contains a brief discussion of Phase 2 requirements.

PNW - PSW Intertie

The NFPeis assumes that the Long Term Intertie Access Policy remains in force throughout the study horizon. The first 800 MW of the Third AC comes in service January 1993 with the remaining 800 MW operational in November 1993. With completion of the Third AC, the total intertie size is 7900 MW of which PGE owns 950 MW and PacifiCorp owns 400 MW. Of the remaining capacity, 800 MW is filled with assured delivery contracts and another 650 MW is filled with existing Federal marketing and joint venture contracts. This leaves 5100 MW of the intertie available for spot market transactions in the `no action' case (see Chart 1).

Wholesale Rates

The rates charged by BPA for power sales and transmission activities are consistent with the 1991 Wholesale and Transmission Rate Schedules and the November 1991 Wholesale Power Rate Projections document.

California/Inland Southwest

California market data included in the SAM is provided by the Accelerated California Market Estimator (ACME). The base ACME data is derived from the California Energy Commission Draft 1992 Energy Report. Fuel price forecasts are based on the June 1992 BPA long term forecast of oil and gas prices.

Federal Marketing

The Federal marketing (FM) case analyzes the environmental impact associated with the marketing of incremental streamflows due to flow requirements for fish passage during May and June. The SAM portrays this alternative in two separate parts. The first option (FM Case A) adds a firm power seasonal diversity export to the Southwest during May and June of 1100 MW peak and 1100 aMW energy. The energy associated with this export is returned to BPA during the offpeak hours of the months October through March. Case A also includes a capacity energy exchange contract of 1100 MW during the months of July through September with the return of the exchange energy deferred until the October through March period.

Federal marketing Case B includes elements of the above but is geared to combining the use of incremental flows with other firm contracts using the intertie to access the California market. In this case, a firm power export of 1100 MW peak and 1100 aMW energy, during all months of the year, is added to the SAM data. This contract flows over the BPA portion of the intertie as a joint venture type of contract: The resource used to serve this contract comes from outside of BPA during the months of July through April. During May and June, BPA supplies this firm contract with the same type of seasonal diversity contract as noted above. The energy associated with the two month delivery is returned to BPA offpeak during the months of October through March.

Both Case A and B alter the `no action' case intertie allocation by increasing the portion used for Federal marketing. In Chart 1, it is shown that the intertie allocation for Federal marketing goes from 650 MW to 1750 MW. This has the effect of reducing the intertie space remaining for spot transactions from 5100 MW to 4000 MW.

Capacity Ownership

In the capacity ownership (CO) case, 725 MW of Federal intertie capability is transferred to non-Federal owners. The CO case thus reduces the portion of the intertie available for spot market transactions from 5100 MW to 4375 MW (see Chart 1). Modeling this option in the SAM required some specification of how the 725 MW would be allocated among the non-Federal users and what types of contracts would flow over that portion of the intertie.

Allocation Methodology

The NFPeis considers environmental impacts based on a `bounding' approach. The intent is to determine a set of alternatives that represent the bounds of all

possible expected outcomes. That way, any decision that is made will fall within the analyzed bounds and, consequently, within the analyzed environmental impacts. This approach was applied to the specification of the allocation methodology employed in the SAM.

BPA executed Memoranda of Understanding (MOU) with those entities indicating an interest in obtaining a portion of the available 725 MW. The total amount of interest ranged from a low of 1170 MW and a high of 1542 MW. The NFPeis allocation scheme employed in the SAM was to allocate the 725 MW over the IOUs and Publics based on the indications provided by the MOUs. Of the total amounts requested, the IOUs accounted for an average (an average of the high and the low request for each group) of 48% and the Publics accounted for 52%. These percentages were applied to the 725 MW with a resulting 350 MW going to the IOUs and 375 MW going to the Publics. The other alternative is to assign all of the 725 MW to the Publics. For the purposes of the NFPeis, these two allocation alternatives are felt to bound the actual allocation scheme that may result.

Contract Alternatives

The `bounding' approach is also applied when specifying alternative contract types considered in the NFPeis There are two types of contracts that would most likely represent the variety of contracts that would flow over the intertie. These two are seasonal exchange contracts and annual firm power sale contracts. The two alternatives modeled in the SAM are one where the 725 MW is filled with firm power exports and another where it is filled with seasonal exchange contracts.

The firm power sale is modeled as a firm export for 12 months of the year delivered at a 100% load factor. The seasonal exchange contract was modeled as a firm export during the months June through September and as a firm import during the months November through February. Both the export and the import portions are delivered at a 100% load factor. The rationale for the four month delivery and return is based on existing seasonal exchange contracts between PNW and PSW utilities. The 1991 Whitebook lists five such contracts, four of which are delivered June through September and one that is delivered May through September. Three of these contracts are returned November through February, one is returned November through March, and one is returned December through March. The decision to deliver at a 100% load factor is directly related to the fact that the SAM is an energy model and a 100% load factor will generate the largest energy impact. This is once again a result of the `bounding' approach.

Resource Acquisitions

When developing the contract alternatives, the issue of resource acquisitions surfaced. Resource acquisition decisions are assumed in the NFPeis to be made on the basis of annual deficits. With a hydro based generation system, the opportunity exists for water to be shaped from one month to the next to handle monthly or shorter term resource deficits. However, if a deficit occurs on an annual basis, just shaping water will not solve the shortage since there is a planning deficit. Consequently, for those cases where a non-Federal participant enters into a firm power export contract that creates an annual deficit, combined cycle combustion turbine generation is added to the resource stack modeled in the SAM.

The assumption, particularly with respect to the Publics, is that export contracts to the Southwest that create an increase in annual load, will not increase the annual load placed on the Federal system. The SAM assumes that all Public agency load in excess of their own resources is placed on the Federal system as net requirements customers. If the Publics were to write an export contract without adding some resource to serve that contract, additional net requirement load would be placed on BPA

This result does not apply to the seasonal exchange contracts. Seasonal exchange contracts net to zero on an annual basis. While the annual load placed on BPA by a Public that writes a seasonal exchange contract does not change, there are changes in the monthly loads. During the periods of export or delivery, the load placed on BPA will likely increase. However, when the contract takes the form of the import, the load placed on BPA is reduced.

The NFPeis considers the environmental impact associated with non-Federal participation in the intertie. The assumptions concerning contract types and resource requirements in the capacity ownership case are intended to generate the most significant impact while still remaining consistent with expected BPA policy.

Assured Delivery

The assured delivery (AD) case considers the impact of increasing the intertie space dedicated to assured delivery contracts from the current 800 MW to 1525 MW, an increase of 725 MW. This case requires the same set of assumptions concerning allocation of the increased assured delivery, contract types that may use the additional space, and resource acquisition requirements. All of the assumptions made in the capacity ownership case apply to the increased assured delivery case as well. All provisions regarding assured delivery as

specified in the Long Term Intertie Access Policy apply to the additional 725 MW.

In Chart 1, it can be seen that the assured delivery case does not alter the amount of intertie space remaining for spot transactions over that shown for the capacity ownership case. The fundamental difference between the two cases is how unused intertie capacity is treated in the SAM. Under the capacity ownership case, the 725 MW is reserved exclusively for the use of the owner at all times. If some of the capacity is unused, it will remain so. Under the assured delivery case, the 725 MW is available for exclusive use of the subscriber only during times that the contract is being delivered. During other times, any unused intertie space is allocated under the provisions of the Long Term Intertie Access Policy.

Cumulative Alternatives

It is reasonably clear that BPA will attempt to mitigate the impacts on the power system associated with increased fish related flow requirements. This mitigation will include some sort of increased Federal marketing. It is also the case that BPA's preferred alternative with respect to non-Federal participation in the intertie is the capacity ownership alternative. In any event, it is likely that the final outcome will include some combination of the individual alternatives described above. Consequently, the NFPeis includes cumulative alternatives that analyze the combined effects of certain actions. These alternatives combine the Federal marketing cases A or B with the various capacity ownership and assured delivery cases. Chart 2 indicates the effect of these combinations on the intertie allocation. In the federal marketing case 4000 MW of intertie capacity remains for spot market sales. When adding an additional 725 MW of capacity ownership or assured delivery, the amount remaining for spot sales declines to 3275 MW.

STUDY SENSITIVITIES

To arrive at an overall estimate of environmental impacts, each of the specified alternatives are sometimes considered under a series of alternate assumptions or sensitivities. These sensitivities could include varying the regional load forecast from high to medium to low and/or varying the price forecast of natural gas in the Southwest from high to medium to low. Load forecast variations will alter the types of resources acquired to meet load growth or generate a situation where the region has surplus resources. Since natural gas is the fuel for the California resources displaced by purchases from the Northwest, adjusting the price of gas directly affects the value of the market faced by this region. These

variations create situations where alternative use of the intertie has significantly different values and potentially different environmental impacts.

Chart 3 presents a decision tree listing all possible study combinations of the alternatives previously identified. If one were to analyze all 27 of the alternatives under each of the three load forecasts matched with each of the three Southwest gas price sensitivities, the total number of studies generated would be 243. This large amount of information is unnecessary to adequately consider a viable range of environmental impacts. It is possible to logically winnow out those studies that are redundant or do not provide information that would alter any given decision. This study minimizing process assumes that environmental assessment requirements can be met by `bounding' environmental impacts by considering those sensitivities that would create the most significant impacts under a given set of alternatives. This procedure would then provide environmental coverage for any decision that represents a result that falls anywhere between the bounds considered.

Load Forecast Sensitivities

Load forecast sensitivities can create significant changes in expected results. Under the low load forecast, the regional entities have a surplus of resources. With a surplus, as compared to a balanced system, more sales will be made over the intertie, more resources may be displaced, and the hydro system may be operated differently because of the surplus. When estimating a `boundary' for impacts associated with non-federal ownership of the intertie, the SAM needs to be operated assuming surplus conditions. Thus, the NFPeis studies include the low load sensitivity.

With current projections, both the high and medium load forecast exceed regional resource capability. From a planning standpoint, resources would be acquired to balance system loads and resources under conditions of adverse water. The major difference between these two load forecasts, when applied to a SAM analysis, concerns the types of resources acquired to create a balanced system under each forecast. With the high load forecast, the resources acquired would include all of those needed to meet the medium load forecast plus other resources. These other resources could include resource types not considered in the medium case such as coal or nuclear generation. The SAM depiction of system operation does vary greatly depending upon whether the system is surplus or balanced. System operation does not show large variation when considering two situations where both are-balanced. The difference in balanced operation lies in the amounts and types of resources added and how the hydro system can best be used to minimize the overall operating cost. Selecting the high load case as a sensitivity provides the greatest opportunity for assessing

effects on system operation due to altering intertie ownership primarily due to the large number and variety of resource additions with high loads. The `bounding' argument implies that the NFPeis studies consider high loads and that studies based on the medium load forecast can be disregarded since their results would fall between the high and low cases.

Southwest Natural Gas Price Sensitivities

The forecasted cost of natural gas supply to utilities in the Southwest is important when estimating the impact of changing the amount of Federal ownership in the intertie. An input to the SAM is an estimate of the decremental (i.e. the cost saved by displacing or not operating the resource) operating cost of Southwest generating resources. This decremental cost is directly related to the cost of natural gas since that is the fuel of choice for most of those displaceable resources. To make an argument concerning the use of any particular gas forecast, it is important to understand the basics of how the Southwest market is calculated and applied in the SAM.

Intertie capacity has value because it allows for firm export contracts, firm import contracts, and spot market economy energy sales between the Northwest and the Southwest. The SAM assumes that Northwest exports to the Southwest are used by Southwest utilities to displace operation of their highest cost resources. Consequently, the data in the SAM indicating the size and value of the Southwest decremental resource market is reduced alter accounting for Northwest export contracts. Northwest firm imports from the Southwest augment the Northwest resource base and essentially expand the size of the Southwest market because imports are displaceable by Northwest resource operation. The Southwest decremental cost market, as adjusted for export and import contracts, is then used in the SAM to determine the market for economy energy sales.

Basically, the SAM estimates spot market sales of economy energy over the intertie by comparing the incremental (i.e. the cost incurred to generate an additional unit of energy) cost of generation by Northwest entities to the decremental cost of generation in the Southwest.

On an operational basis, when the differential between the Northwest incremental cost and the Southwest decremental cost is large, there is more opportunity to make economic energy sales to the southwest. This increased opportunity translates into an increased value for those Northwest entities that have access to the intertie and an increased value for the intertie itself. When estimating the value of ownership rights in the intertie or the impact associated with alternative firm contract types, it is more environmentally and economically significant to test this value when the cost differential is the greatest. The

NFPeis studies assume that the Southwest is experiencing a forecast of high natural gas prices.

Alternatives Considered

In addition to reducing the various sensitivities, there are some of the alternatives that do not need to be analyzed. As noted in the alternative description section there is very little difference between the assured delivery and capacity ownership alternatives. The only difference noted related to the use of unused intertie capacity. The assumption was made when designing the firm power export sale contract that the contract was delivered 24 hours a day all year round. This contract type was proposed to be analyzed under both the capacity ownership and assured delivery alternative. For this alternative, it can be seen that the contract continually fills all of the intertie space available under both the assured delivery option and the capacity ownership option. There is no unused capacity to be allocated in a different manner between the two alternatives. There is also no need to analyze both the assured delivery and capacity ownership cases when considering the firm export contract case since the results will be identical. Consequently, the NFPeis has deleted from consideration all those SAM studies that included the firm export sale with the assured delivery alternative. These studies are shown in Chart 3 as lines 7, 9, 17, 19, 25, and 27.

By reducing the sensitivities to include only the high Southwest gas forecast, the high and low load forecast, and only those SAM studies that are needed greatly reduces the number of SAM studies required. A full listing of the required SAM studies is presented in Chart 4. This chart shows that the `bounding' approach has reduced the total number of studies from 243 to a more manageable 42.

Figure (Page F19 Chart 1 NFP-eis INTERTIE ALLOCATION DISCRETE ALTERNATIVES)

Figure (Page F20 Chart 2 NFP-eis INTERTIE ALLOCATION CUMULATIVE ALTERNATIVES)

Figure (Page F22 Chart 3 NFP-eis DECISION TREE SYSTEM ANALYSIS MODEL STUDIES)

Figure (Page F23 Chart 4 NFP-eis DECISION TREE SYSTEM ANALYSIS MODEL STUDIES)

Table F-1 BPA RESOURCE ADDITIONS FOR HIGH LOADS AVERAGE MW

OP YeaR	DATE	CONS	RENS	PURCH	COMBINED CYCLE CT	COAL	WNP 3	TOTAL
1993	Sep-92	64	0	1230				1294
1994	Sep-93	117	95	1230				1442
1995	Sep-94	179	159	1476				1814
1996	Sep-95	248	417	1230				1895
1997	Sep-96	322	417	0	1460			2199
1998	Sep-97	402	417	0	1460			2279
1999	Sep-98	484	417	0	1825			2726
2000	Sep-99	571	417	0	1825			2813

2001	Sep-00	657	417	0	2190			3264
2002	Sep-01	738	552	0	2190			3480
2000	Sep-02	821	556	0	2190			3567
2004	Sep-03	901	560	0	2190		806	4457
2005	Sep-04	988	568	0	2190		806	4552
2006	Sep-05	1080	816	0	2190		806	4892
2007	Sep-06	1168	1010	0	2190		806	5174
2008	Sep-07	1246	1022	0	2190		806	5264
2009	Sep-03	1324	1026	0	2190		806	5336
2010	Sep-09	1397	1026	0	2190		806	5419
2011	Sep-10	1397	1026	0	2190		806	5419
2012	Sep-11	1397	1026	0	2190		806	5419

Purchases modeled as Simple Cycle CTs

Simple Cycle CTs = 246, Combined Cycle CTs = 365, COAL = 426, WNP 3 = 806

Renewables are Solar, Goethermal, Cogeneration, Small Hydro, etc.

Table F-2 IOU RESOURCE ADDITIONS FOR HIGH LOADS AVERAGE MW

OP YeaR	DATE	CONS	RENS	PURCH	COMBINED CYCLE CT	COAL	WNP 3	TOTAL
1993	Sep-92	10	0	984				994
1994	Sep-93	54	15	1230				1299
1995	Sep-94	142	30	1722				1894
1996	Sep-95	250	655	1230				2135
1997	Sep-96	364	975	738	1095			3172
1998	Sep-97	479	2131	0	1095			3705
1999	Sep-98	595	2488	0	1095			4178
2000	Sep-99	717	2828	0	1095			4640
2001	Sep-00	839	3137	0	1095			5071
2002	Sep-01	961	3205	0	1095			5261
2003	Sep-02	1083	3226	0	1095	426		5830
2004	Sep-03	1202	3244	0	1095	852		6393

2005	Sep-04	1308	3281	0	1095	1278	6962
2006	Sep-05	1394	3281	0	1095	1704	7474
2007	Sep-06	1478	3281	0	1095	1704	7558
2008	Sep-07	1563	3585	0	1095	2130	8373
2009	Sep-08	1645	3693	0	1095	2556	8989
2010	Sep-09	1727	3733	0	1095	2556	9111
2011	Sep-10	1727	3733	0	1095	2982	9537
2012	Sep-11	1727	3733	0	1095	3408	9963

Purchases modeled as Simple Cycle CTs

Simple Cycle CTs = 246, Combined Cycle CTs = 365, COAL = 426, WNP 3 = 806

Renewables are Solar, Goethermal, Cogeneration, Small Hydro, etc.

Table F-3 BPA RESOURCE ADDITIONS FOR MEDIUM LOADS AVERAGE MW

OP YeaR	DATE	CONS	RENS	PURCH	COMBINED CYCLE CT	COAL	WNP 3	TOTAL
1993	Sep-92	56	0	492				548
1994	Sep-93	103	95	492				69O
1995	Sep-94	159	154	246				559
1996	Sep-95	221	412					633
1997	Sep-96	288	412					700
1998	Sep-97	360	412					772
1999	Sep-98	435	412					847
2000	Sep-99	512	412		365			1289
2001	Sep-00	587	412		365			1364
2002	Sep-01	657	412		365			1434
2003	Sep-02	730	412		365			1507
2004	Sep-03	772	421		365			1558
2005	Sep-04	815	425		365			1605
2006	Sep-05	863	429		365			1657
2007	Sep-06	921	432		365			1718
2008	Sep-07	980	437		365			1782
2009	Sep-03	1038	440		365			1843
2010	Sep-09	1097	440		365			1902
2011	Sep-10	1097	440		365			1902
2012	Sep-11	1097	440		365			1902

Purchases modeled as Simple Cycle CTs

Simple Cycle CTs = 246, Combined Cycle CTs = 365, COAL = 426, WNP 3 = 806

Renewables are Solar, Geothermal, Cogeneration, Small Hydro, etc.

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Table F-4 IOU RESOURCE ADDITIONS FOR MEDIUM LOADS AVERAGE MW

OP YeaR	DATE	CONS	RENS	PURCH	COMBINED CYCLE CT	COAL	WNP 3	TOTAL
1993	Sep-92	5	0	0				5
1994	Sep-93	43	5	246				294
1995	Sep-94	118	20	492				630
1996	Sep-95	208	109	492				809
1997	Sep-96	304	378		1095			1777
1998	Sep-97	402	423		1095			1920
1999	Sep-98	503	702		1095			2300
2000	Sep-99	605	819		1095			2519
2001	Sep-00	706	919		1095			2720
2002	Sep-01	790	1188		1095			3073
2003	Sep-02	873	1316		1095			3284
2004	Sep-03	953	1473		1095			3521
2005	Sep-04	1027	1626		1095			3748
2006	Sep-05	1098	1634		1095			3827
2007	Sep-06	1165	1682		1095			3942
2008	Sep-07	1230	1905		1095			4230
2009	Sep-08	1295	2018		1095			4408
2010	Sep-09	1361	2066		1095	426		4948
2011	Sep-10	1361	2066		1095	426		4948
2012	Sep-11	1361	2066		1095	426		4948

Purchases modeled as Simple Cycle CTs

Simple Cycle CTs = 246, Combined Cycle CTs = 365, COAL = 426, WNP 3 = 806

Renewables are Solar, Geothermal, Cogeneration, Small Hydro, etc.

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Table F-5 BPA RESOURCE ADDITIONS FOR LOW LOADS AVERAGE MW

OP COMBINED

YeaR	DATE	CONS	RENS	PURCH	CYCLE CT	COAL	WNP 3	TOTAL
1993	Sep-92	52	0					52
1994	Sep-03	93	95					188
1995	Sep-94	143	154					297
1996	Sep-95	201	412					613
1997	Sep-96	263	412					675
1998	Sep-97	331	412					743
1999	Sep-98	400	412					812
2000	Sep-99	468	412					880
2001	Sep-00	534	412					946
2002	Sep-01	596	412					1008
2003	Sep-02	660	412					1072
2004	Sep-03	663	412					1075
2005	Sep-04	667	412					1079
2006	Sep-06	670	412					1082
2007	Sep-03	673	412					1085
2008	Sep-07	677	412					1089
2009	Sep-03	681	412					1093
2010	Sep-09	685	412					1097
2011	Sep-10	685	412					1097
2012	Sep-11	685	412					1097

Purchases modeled as Simple Cycle CTs

Simple Cycle CTs = 246, Combined Cycle CTs = 365, COAL = 426, WNP 3 = 806

Renewables are Solar, Geothermal, Cogeneration, Small Hydro, etc.

Table F-6 IOU RESOURCE ADDITIONS FOR LOW LOADS AVERAGE MW

OP YeaR	DATE	CONS	RENS	PURCH	COMBINED CYCLE CT	COAL	WNP 3	TOTAL
1993	Sep-92	2	0					2
1994	Sep-93	18	0					18
1995	Sep-94	51	0					51
1996	Sep-95	108	0					108
1997	Sep-96	182	5					187
1998	Sep-97	261	15					276
1999	Sep-98	326	33					359
2000	Sep-99	381	37					418
2001	Sep-00	440	40					480
2002	Sep-01	504	106					610
2003	Sep-02	569	115					684
2004	Sep-03	625	124					749
2005	Sep-04	679	132					811
2006	Sep-05	738	141					879
2007	Sep-06	796	150					946
2008	Sep-07	851	159		365			1375
2009	Sep-08	900	165		365			1430

2010	Sep-09	949	165	365	1479
2011	Sep-10	949	165	365	1479
2012	Sep-11	949	165	365	1479

Purchases modeled as Simple Cycle CTs

Simple Cycle CTs = 246, Combined Cycle CTs = 365, COAL = 426, WNP 3 = 806

Renewables are Solar, Geothermal, Cogeneration, Small Hydro, etc.

Appendix F. Part 3. Hydro System Operation

SECTION 1: Important Terms and Concepts

SECTION 2: Hydropower System Planning and Operation

SECTION 1 IMPORTANT TERMS AND CONCEPTS

Federal Columbia River Power System (FCRPS) as a Multi-Use System

The Federal Columbia River Power System serves multiple purposes in addition to power generation: flood control, navigation, recreation, irrigation, fishery benefits, and other such non-power uses. BPA markets the power from FCRPS projects pursuant to the Bonneville Project Act and other Federal legislation and orders. FCRPS projects are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. BPA and these agencies have Memorandums of Understanding recognizing each others' responsibilities and establishing operating arrangements. Non-power uses and electric power production are brought together in the development of "operating requirements" (see following discussion of Operating Requirements).

The Pacific Northwest Coordination Agreement (Coordination Agreement)

The electric utilities of the Pacific Northwest plan and operate their systems in a coordinated manner. BPA plays a major role in this planning. This planning is carried out under the specifications of the Agreement for Coordination of Operations among Power Systems of the Pacific Northwest, also known as the Pacific Northwest Coordination Agreement. The Coordination Agreement's major provisions deal with preparation of the Annual Operating Plan, and the monthly, weekly, and daily operations of the parties' generating systems. Coordination of reservoir operations is given special attention, particularly when there is diverse ownership of generating plants downstream from a reservoir.

The Coordination Agreement does not cover two significant aspects of coordination: long-range planning of new resources, and short-term hour-by-hour coordinated operation of generating facilities.

All major generating utilities in the Pacific Northwest are parties to the Coordination Agreement, except The Idaho Power Company. Idaho Power does coordinate its Brownlee Reservoir operations in concert with the Agreement to a certain extent. Joint planning is essential because the system utilities are interconnected electrically through shared transmission facilities, and hydraulically through the effect of released water on downstream hydroelectric projects. The advantages to the region of operating a coordinated system are:

* ability to take advantage of more efficient operation of hydro resources;
* ability to exchange power among member utilities;
* assistance gained during emergency outages of transmission lines or generators;
* ability to take advantage of diversities among systems in loads, generation, and maintenance outages; and

* reduced overall costs from coordinated use of all facilities and elimination of duplicative or multiple generation, transmission, and control facilities.

Reservoir-owning parties and parties with downstream generating plants coordinate storage and release of water and interchange power among systems to achieve more efficient use of the hydro system for the region and greater guarantees of meeting firm load.

Annual Operating Plan

Each year, an operating plan is prepared for the next July-June operating year. It combines the operating characteristics of thermal and hydroelectric plants, load forecasts, and historical streamflows to determine system capabilities. It uses monthly (sometimes half-month) time increments. It describes loads and resource capabilities in terms of two quantities -- average energy for monthly periods, and peak load or generating capability during the month. The purpose of the Annual Operating Plan is to determine how much load can be served with existing resources.

Determination of the Multi-Year Critical Period and FELCC

Preparation of the Annual Operating Plan starts in February of each year. Participants in the Coordination Agreement (BPA, various investor-owned utilities, public utilities, and hydroelectric project operators) submit loads, resources, and operating requirements for a multi-year period (that is, each year, they submit data for the next 4 years) for use in developing an Annual Operating Plan. The Northwest Power Pool Coordinating Group then uses a computerized model to produce the Actual Energy Regulation study to determine the critical period for the coordinated system and the total Firm Energy Load Carrying Capability (FELCC) for the coordinated system and for each member system.

The Critical Period

The critical period is that portion of the historical 50-year streamflow a record which, when combined with draft of all available reservoir storage, will produce the least amount of energy, with energy used according to seasonal load patterns. At present, the coordinated system's critical period is about 3-1/2 years long, encompassing the historical period from September 1928 through February 1932.

Prior to the construction of the three "Canadian Storage" reservoirs and the Libby dam, the coordinated system's critical period was about 8 months long, encompassing the historical months from September 1936 through April 1937. The the data on actual water conditions that prevailed during the critical period are used with current data on loads and resources to determine FELCC.

Firm Energy Load Carrying Capability (FELCC)

FELCC is the level of energy capable of being produced by the hydro system using all of the reservoir storage in combination with critical period streamflows. FELCC is used to determine the levels to which the coordinated system's reservoirs may be drafted to produce firm energy. The Coordination Agreement's published annual operating program includes the FELCC for each month of the coming operating year for the coordinated system and for each participant.

The planning model takes into account the requirements imposed on the system (flood control, navigation, irrigation, the Water Budget, and other factors).

An important concept of the Coordination Agreement is that the energy studies are made by using the total coordinated system as if it were a single-ownership system.

Operating Requirements

FCRPS plants are operated to produce power within "operating requirements," some of which describe the physical operating limits of the project, and some of which prioritize the use of the project between power and non-power uses. Operating requirements may limit maximum or minimum reservoir levels, project outflows, spills, rates of change of outflows, or many other operating parameters. These limits are often different for various times of the year.

Operations planning is another important guide to FCRPS operation, and to the trade-offs between power and non-power functions of each project.

At the time each hydroelectric project is designed, numerous operating parameters are defined. These include the maximum and minimum reservoir elevations, minimum outflows, and other parameters. Operating limits sometimes include maximum rates of change of reservoir levels or outflows. Some may be the direct result of physical design parameters: for example, the minimum reservoir elevation may be determined by the vertical placement of the outlet works. Some may be to preserve existing river uses. A good example of this is the minimum project outflow. Some operating requirements may be established to obtain benefits for uses other than power, for example, minimum outflows may be established to provide water for irrigation or for downstream navigation. Minimum reservoir elevations may be established to permit navigation or recreation on the reservoir. Flood control operation of typical Pacific Northwest reservoirs results in some of the most complex operating requirements. These usually vary both seasonally and with forecasts of runoff.

To the extent these requirements are established during the design phase, they are taken into account in the studies which determine the feasibility of the project. After a project begins operating, additional operating requirements may have to be established, possibly because some effect of operations was overlooked in the design phase or because conditions have changed.

While some requirements are very definite, for example, those based on the physical characteristics of the project, others may be simply a priority of use. Frequently, non-power requirements can be met without adversely impacting power production. However, when similar requirements are applied to many FCRPS projects, meeting them all may become impossible. Some requirements are more definite, while others express a desire for a certain operation if it is possible without impacting other uses.

Annual Spill Plans

Until mainstem Columbia and Snake River projects are properly screened to protect fish runs, the Council's Fish and Wildlife Program calls for spills of water to carry fish over dams instead of letting the fish pass through the turbines. Enough spill must be provided to protect at least 90 percent of the young fish at each project through the middle 80 percent of the runs. The Program calls for project owners and operators to develop and implement spill plans. These plans list percentages of spill for specific projects. Development and implementation of spill plans are multi-party efforts involving fishery agencies and tribes and project owners and operators.

BPA and fishery agencies and tribes have developed a 10-year spill agreement which would set forth spills at specific projects pending completion of other acceptable bypass methods.

Water Budget

The Northwest Power Act gave BPA significant new responsibilities to mitigate the effects of the development and operation of the FCRPS on fish and wildlife. These activities are conducted with the guidance of the Northwest Power Planning Council's Fish and Wildlife Program. One of the first measures taken by BPA and hydro project operators to carry out the Council's first Program was the implementation of the first Water Budget in 1983. BPA treats the Water Budget as a firm operating constraint that allows for the Fish Passage Managers to request certain levels of flow in the Columbia and Snake Rivers between April 15 and June 15 to help juvenile salmon and steelhead achieve their downstream migration to the sea. For the Water Budget, water is reserved in the reservoirs and is released, either through the turbines or as spill, depending on the demand for energy, at times and in quantities as specified by the Fish Passage

Managers within the guidelines of the Water Budget plan. The Water Budget results in an amount of Firm Energy Load Carrying Capability (FELCC) to be produced in the April 15 to June 15 period which is in excess of the demand for firm energy. It results in an overall decrease in the amount of firm power which can be produced to meet the region's firm loads. This decrease is borne collectively by the Coordination Agreement parties. Affected parties, including BPA, attempt to store the excess firm energy from April 15 to June 15 outside the Columbia River Basin or market it.

Flow Augmentation

The NWPPC's Phase II Amendments to the Fish and Wildlife Program call for an expanded water budget operation on the Snake River and an operational water budget on the Columbia River to be used in conjunction with the existing water budget volume.

The existing water budget of 3.45 million acre-feet (MAF) is still available in the Columbia for spring time flow augmentation. For poor to moderate water years, the Phase II amendments call for the storage of an additional volume of water. The amount to store varies based on the January - July runoff volume forecast and can not exceed 3 MAF. The water is stored at Grand Coulee and Arrow.

For poor water years, the Phase II Amendments call for an increase in water budget volume at Dworshak of 900 thousand acre-feet (KAF) in excess of minimum flows during May and June. In addition, the four lower Snake projects are to operate within one foot of minimum operating pool elevations during the migration period. At John Day the desired operation is near one foot of minimum irrigation elevation.

Refill

Each year, Coordinated System Operations endeavor to refill reservoirs each summer to what is referred to in the Coordination Agreement as "normal top elevation." Operations during the year are constantly analyzed in light of best available data to check their effect on probability of refill.

SECTION 2 Pacific Northwest Hydropower System Planning and Operation

Introduction

The Pacific Northwest depends on its hydroelectric power system for a large percentage of its electric power needs. The amount of runoff in this system is highly variable. The average annual runoff is about 134 million acre-feet (MAF), but in the past has varied from a low of about 78 MAF to a high of 193 MAF. The monthly mean streamflow (unregulated), as measured at the Dalles, Oregon, can range from 40,000 cubic feet per second (cfs) in January to 1,240,000 cfs in May.

The hydro system consists of many "run-of-river" projects with limited daily or weekly storage, and a few much larger "seasonal storage" projects whose storage may be drawn upon over a year or more before emptying or refilling. Since streamflows do not occur in the same pattern as electric energy requirements, the water is used as a storage medium for potential energy. The streamflow pattern is regulated into a more usable shape by controlling project outflow to store energy when natural streamflows exceed load requirements, and to release stored energy as needed. The total storage capacity of the system is only about 42 MAF, nearly half of which is located in Canada. The Canadian portion of the storage is operated by BC Hydro, with the U.S. rights determined by the Columbia River Treaty. Because of the low storage capacity compared with runoff, the hydro system has the potential of producing about 12,000 average megawatts (aMW) of energy as "firm" during low runoff conditions. It can generate about 16,000 aMW on a long-term average basis, and about 19,000 aMW in a high runoff year. This means that in planning the coming year there is an additional unknown factor; up to 7,000 aMW of nonfirm energy that may or may not be available.

Seasonal Planning

The operational planning of Pacific Northwest hydro system is based on the Pacific Northwest Coordination Agreement (PNCA). The PNCA is a contract among the parties to that agreement that defines how planning and operation of the hydro system is carried out on a coordinated basis. The Treaty reservoir storage space in Canada is included in the PNCA planning process and is operated to rule curves and refill requirements similar to other Pacific Northwest reservoirs. Planning is based on the "critical period," which is that period using the historical streamflow data base during which the hydro system can produce the least amount of power while drafting the water in the reservoirs allocated to power from full to empty. The amount of power produced under critical water conditions is called "firm." The critical period itself is most often defined as the 42 months of low streamflow from September 1, 1928, through February 29, 1932. This represents the level of risk that the regional utilities have contractually agreed upon under the PNCA in relying on the hydro system to produce firm energy. Since flows are usually better than what occurs under critical water conditions, the amount of additional power produced is called "nonfirm." If all the runoff could be stored in any streamflow runoff year, as is the

case with some other large hydro power systems in the U.S., the hydro system could always produce an average amount of power, and firm energy would be based on average runoff.

The flexibility of the hydro system to "shape" generation to meet load is limited by many requirements. Requirements modeled in the planning process include upper storage limits for flood control or recreation, project minimum and maximum outflows, tailwater restrictions, spills of water from dams to transport juvenile fish around (rather than through) the turbines, and the water set aside for increased streamflows to aid in the downstream migration of fish (the Water Budget). While meeting these and other requirements, hydro system flexibility is used wherever possible for power operations.
By drafting reservoirs earlier in the year to meet higher loads, energy is shifted forward in time, or "borrowed" from the future, up to certain limits. While thermal plants are meeting base loads, the hydro system is meeting both base and peak loads. Nighttime

requirements on the ability to refill plants that have storage capability further limit the system. Operational requirements limit the ability to shift firm energy within the critical period. These requirements place limits on the amount of reservoir drawdown permitted at certain times during the year.

In planning for each coming operating year, Northwest utilities prepare a critical period study in accordance with the PNCA. This study defines certain operational parameters called critical rule curves under which the system will operate. A critical rule curve for a reservoir is a schedule of the end-of-month storage contents attained by that reservoir in the critical period study. Critical rule curves are designed to protect the ability of the hydro system to serve firm load with the occurrence of flows no worse than those of the critical period. For each reservoir, there is a set of four rule curves showing storage contents, one rule curve for each year from July 1928, through June 1932. The critical period study shows how the system would operate if all the loads and resources were in place as forecasted and the historical critically low streamflows reoccur. The study also defines the amount of load the system can serve on a firm basis (the firm energy load carrying capability, or FELCC). Operationally, the system reservoirs are drafted proportionately with respect to each reservoirs critical rule curves under noncritical, but highly variable, streamflow conditions.

Operations

The critical rule curves are used along with reservoir refill requirements to develop the generation needed to meet the FELCC regardless of the amount of streamflow that actually occurs. For example, if the flows during the given month are less than the flows used in the critical period study, the system reservoirs would be drafted proportionately according to each reservoir's critical rule curves taking into consideration each project's refill probability. If the flows are higher, but the reservoirs are lower than the rule curves, then the reservoirs could be proportionately filled to the rule curve while meeting firm loads. If the system is surplus when compared with critical water conditions, then nonfirm energy would be offered to displace higher cost Northwest thermal resources, exported out of the region, stored in reservoirs, or spilled. Note, however, that the Northwest under the PNCA would not draft the reservoirs below their rule curves to

serve nonfirm markets because that would jeopardize the system's ability to meet its FELCC in the remainder of the operating year. In addition, this would also impair the ability of the system to refill all reservoirs by July 31 of each year.

Ideally, the system refills each summer. By late summer, in most years, the snowpack in the region has melted, causing the streamflows to recede sharply. In order to continue meeting FELCC, reservoirs must be drafted. In some years, climatic conditions are such that the system is surplus and some nonfirm energy is available in the fall or early winter. In January, the first snowpack measurements and the first forecasts of the January through July runoff are made. Flood control curves are developed to prevent flooding in the spring and refill requirements are developed so as to insure that firm loads are met and system reservoirs are refilled by July 31. This would not be difficult if accurate forecasts of the January through July runoff were available. However, the January forecast is based on actual snowpack and projected precipitation through July. The future precipitation can vary greatly from projections and since most storage reservoirs and drainage areas are relatively remote, little accurate data are available on the amount of snowpack loss or gain between snowpack surveys. Even with January through July runoff projections updated monthly, a project may run at maximum generation one month for flood control, and then because of an unexpectedly low snowpack measurement, be run at minimum the next month in order to refill. The closer to July, the more accurate the forecast, since less of it is based on future precipitation. Unfortunately, if a reservoir is drafted too much early in the season based on a high projected runoff, it may be impossible to refill if precipitation is much below normal. Likewise, if it is not drafted enough, flood control will force water to be spilled, a loss that can run to tens of thousands of dollars per hour. With an annual runoff that varies between about 60 percent and 145 percent of normal and limited storage space, hydro operations is really a continual balancing act between maximizing revenues and the need to refill annually for recreation, fisheries, and to assure future energy needs.

Differences Between Hydro and Thermal Systems

A major difference between hydro and thermal systems is the time it takes to bring generation on line. A thermal plant can require hours, or even days, to reach maximum output, while hydro units can be brought on line in a few minutes. A coal or nuclear plant is limited in its ability to ramp up or down, while a hydro system can usually call upon a large number of units to be brought on line singly or in groups. A thermal plant's fuel supply can be controlled within certain limits while there is very limited control over the hydro system's "fuel" due to variations in the amount of the spring runoff, or the runoff from sudden rainstorms or snowmelts. Moreover, as previously discussed there are significant restrictions on the ability of the hydro resource to generate power because of the need to refill reservoirs, the requirements to maintain specific elevations for flood control, wildlife, recreation, navigation, or irrigation; and the requirement to provide flows for fish migration, recreation, and navigation.

Appendix F. Part 4. PNW Resource Operation Results

Resource Operation Impacts

Overview

Contract types and intertie use alternatives modeled in the NFPeis affect the operation of resources in the Pacific Northwest (PNW), Canada (BCH), and the Pacific Southwest (PSW). This appendix discusses those operational impacts.

Study results are presented in three major categories related to contract type. Twenty-one different scenarios were modeled and tested with the SAM. This discussion combines alternatives into those that include seasonal exchange (SE) contracts, those that include power sale (PS) contracts, and those that represent combinations of both PS and SE contracts. Operational impacts for the federal marketing (FM), capacity ownership (CO), and assured delivery (AD) alternatives are identified for each of the three regions noted above. For BCH, the impact is changes in generation associated with increased exports from Canada to the PNW and PSW. For the PNW, the analysis considers changes in hydro, coal, and combustion turbine generation used to serve regional and PSW loads. For the PSW, information concerning the change in PSW resource operation due to the added import and export contracts as well as economy energy purchases from the PNW and BCH is considered.

SAM generated operational data for each alternative is presented in a series of tables at the end of this appendix. Table 1 provides the operational data for the no action (NA) case in average megawatts (aMW). The remaining tables contain data for each of the alternatives presented in three separate formats. The main table contains the total generation in aMW for each category. A second table (labeled subtable A) presents the data in percentage changes from the NA case. A third table (labeled subtable B) shows the differences from the NA case in aMW. The A and B subtables are helpful in maintaining a proper perspective. In some instances, the change in aMW appears quite large yet it represents a small change relative to the total amount. The opposite condition can also exist. Consequently, both subtables provide information useful in determining the relative impact of any given alternative.

Data for each region is presented under the high and low load forecasts on a monthly basis with the lad column showing the annual average. The first section identifies PNW generation data for hydro, coal, and combustion turbines (CT). As part of the 'bounding' procedure (see Appendix B) applied to air quality impacts, coal and CT operation is also presented under conditions of low water and high water. Sales to the PSW consist of two categories. The first is economy or spot market sales from the PNW and BCH to the PSW. The net export sales category adds in the amounts of additional firm contracts associated with the alternative including any generation that the PSW needs to

serve return provisions, such as those with SE contracts. BCH data consists of spot market sales to the PNW and to the PSW.

Seasonal Exchange Alternatives

The seasonal exchange (SE) alternatives include the federal marketing case A (FMA) and the assured delivery (AD) and capacity ownership (CO) cases with the intertie allocated 100 percent to the public agencies (AD1 and CO1) and cases with the intertie allocated 52 percent to the publics and 48 percent to investor owned utilities (AD5 and CO5). This grouping also includes combinations of FMA and CO1, CO5, AD1, and AD5. The combinations are included because BPA is attempting to mitigate the impact associated with increased fish related flow requirements through additional federal marketing arrangements and at the same time is committed to either expanding the assured delivery amounts or offering capacity ownership. See Appendix B for a discussion of each of the alternatives.

Federal Marketing Case A (FMA)

Contracts included in this case are designed to sell required fish related flows during their release and have the energy that was delivered returned to BPA during those months when BPA needs it. A power sale contract during May and June is combined with a capacity/energy exchange contract during July through September to create a contract package that could be desirable to PSW parties.

The May/June energy along with the exchange energy associated with the July through September contract is returned to BPA in equal amounts during October through March.

For the PNW, the NA case had a load/resource balance with high loads and a resource surplus under low loads. For the FMA case, the exchange energy returned to BPA changes the load/resource situation under high loads to one of surplus resources and increases the existing surplus under low loads. Consequently, for the FMA case, there is a reduction in PNW hydro, coal, and combustion turbine generation on an annual average basis over both high and low load forecasts (see Table 2-B). There is a shift in the monthly generation patterns due to the seasonal nature of the FMA contracts. As expected, there is a reduction in PNW generation during the winter months when the PSW returns the energy. There is also an increase in PNW generation during May and June. This last result does not necessarily imply that the additional flows during May and June are not capable of producing enough energy to make the 1100 aMW firm sale. In the NA case, as much of the fish related flow as possible is sold as economy energy. In the FMA case, as much as 1100 aMW of the fish flow related energy could be used to serve the firm contract to the PSW. As a result of this sale, there is a reduction in the amount of economy energy available for sale during May and June. There is a reduction in economy energy sales to the

PSW during May and June. This reduction is, however, less than 1100 aMW and generates a result where total sales (economy plus firm) to the PSW are larger than in the HA case. Increases in PNW generation in the FMA case could be related to those increased sales to the PSW and/or it could be related to a reduction in the amount of generating resources displaced because of reduced availability of economy energy. In any event, the result is related to the attempt to firm up the use of the augmented fish related flows.

Operationally, intertie capacity and the size of the PSW market available for economy energy transactions during May and June are reduced by the amount of the firm contract. The size of the PSW market faced by the northern entities increases during October through March because generation can be sold to displace PSW generation needed to serve the returns. The data in Table 2-B shows an increase in economy energy sales to the PSW during the winter months and a decrease in sales during May and June. There is an increase in economy energy sales to the PSW on an annual basis under both high and low load forecasts. The net impact on the PSW, taking into consideration economy energy sales as well as the additional firm contracts, is shown in Table 2-B as Net Export Sales. Due to returns of energy made by the PSW, the region becomes a net exporter on an annual average basis even with the increased economy energy sales. The PSW must increase its generation during the winter to serve the return requirements. There is a reduction in PSW generation during May and June but not enough to offset increased generation in other months.

Sales of economy energy by BCH do not change by a significant amount on an annual average basis. Monthly changes in BCH sales are due to the changing relationship between the PSW and PNW markets as a result of the FMA contracts.

Capacity Ownership (CO)

The capacity ownership case transferred 725 W of intertie capacity to non-Federal owners. The allocations were 1000h to the publics (PUB) (CO1) and 52%/48% PUB/investor owned utilities (IOU), respectively (CO5). In the seasonal exchange case, the 725 MW was filled with a contract delivered to the PSW during June through September and returned from the PSW during November through March. The net effect of this contract on the load/resource balance is zero on an annual basis. Any increase in the monthly load of the PUBs was allowed to be placed on BPA since there would be reductions in the PUB load during those months where the energy was returned.

Tables 3 and 4 present the SAM results for the CO1 and CO5 cases. A comparison of these two cases indicates that there are no significant differences on an annual average basis. Under high loads, there is a slight increase in hydro generation and a reduction in the annual operation of CTs. Hydro and

coal generation under low loads is reduced in both cases. Increases in average annual CT generation under conditions of low loads are related to spot market sales to the PSW. With the value of the PSW market based on a forecast of high gas prices, there are opportunities for economic sales of CT output, especially under conditions of low water.

The monthly changes in generation follow the same pattern as those in the FMA case. Generation tends to increase during those periods of delivery (June through September) and decrease during periods of return. On a monthly basis, differences between CO1 and CO5 relate to what kind of generation was operated or displaced. During November through February, the CO5 case makes more sales south instead of reducing CT operation as in the CO1 case. This result is related to the assumption in the SAM that BPA is limited in the prices it can charge for economy energy by its rate schedule. In the CO1 case, the power returned to the BPA system (in the form of reduced PUB net requirements) has a greater value in the displacement of PNW CT operation. In CO5, a portion of the power coming from the PSW goes to the IOUs that are not rate constrained. For them, the best deal is to sell additional power to the PSW and leave some of the CTs running. This result is also related to the high valued PSW market assumed in these studies.

Similar to the FMA case, intertie capacity and the size of the PSW market available for economy energy transactions are reduced during periods of delivery and increased during periods of return. On an annual average basis, under both high and low loads, there is a decrease in the amount of economy energy sales and a concomitant increase in the amount of generation that the

PSW must commit in returning the power to the PNW., However, the PSW may see annual operational benefits because they are net importers during the spring, summer and early fall which covers the PSW high demand periods.

The reduction in the amount of intertie available and the change in the size of the market affects BCHs ability to sell economy energy to the PSW. However, the increased load in the PNW increases the market for BCH power. Under both load forecasts, there is an increase in the amount of economy energy sold on an annual basis to the PNW and a decrease in the amount sold to the PSW. The net impact on the BCH system is relatively small.

Assured Delivery (AD)

The assured delivery case increased the amount of space on the intertie allocated to assured delivery contracts by 725 MW. This increased AD space was allocated between utility groups in the same manner as the CO cases; 100% to the PUBs (AD1) and 52%/48% PUB/IOU, respectively (AD5). The modeling of the AD cases in the SAM is almost identical to the modeling of the CO cases. The only difference is who gets access to the 725 MW when it is not

filled with an assured delivery contract. In the CO case, the owner has the rights to their share of the intertie at all times, whether they use it or not. In the AD cases, a given contract is moved down the intertie during the hours that it is scheduled. During those hours or months that no AD contract is scheduled, the intertie space reverts back to BPA and it is allocated for use according to the provisions of the Long Term Intertie Access Policy (LTIAP). If the AD contract was for 12 months of the year, 24 hours a day, then there would be no difference between the CO and AD case modeling. In the seasonal exchange contract case there are some months when no AD contract is using the 725 MW of intertie space.

Tables 5 and 6 present the SAM results for the AD1 and AD5 cases. There are no significant operational differences between AD1 and AD5 on an annual basis.

The monthly changes in generation follow the same pattern as those in the FMA and CO cases. Generation tends to increase during those periods of delivery (June through September) and decrease during periods of return. On a monthly basis, differences between AD1 and AD5 relate to what kind of generation was operated or displaced. These monthly changes are similar to those exhibited in the, CO cases and occur for the same reasons.

One difference between the AD impact relative to the NA case and the CO impact relative to the NA case is CT operation under low loads with low water. In the AD cases, annual CT operation under low loads and water is less than in the NA case. CT Operation in the CO cases under similar conditions was greater than in the NA case. This reflects the impact of owning a portion of the intertie versus receiving an allocation under provisions of the LTIAP. Under low loads, where the region is surplus, utilities who had ownership rights in the CO cases may not receive as large an allocation of the available intertie under the AD cases as under the CO cases. With low water conditions, surplus resources are mainly thermal and reduced access to the PSW market through a lower intertie allocation would cause a reduction in the operation of thermal resources to serve the market. CTs are the most expensive thermal resource and are generally the marginal resource when serving the PSW market. Consequently, economy energy sales to the PSW are slightly lower and CT operation is lower in the AD cases than in the CO cases. The impact on SCM is relatively small in the AD cases as well as the CO cases.

Alternative Combinations

Those alternatives representing combinations of AD and CO seasonal exchange contracts and the FMA case were studied with the SAM. These combinations (FMACO1, FMACO5, FMAAD1, and FMAAD5) consider the operational effects of combining increased federal marketing with increased nonfederal use of the intertie.

Operational impacts from the SAM are shown in Tables 7 - 10. On an annual average basis, generation in the PNW is reduced in all cases relative to the NA case and relative to each of the cases on an individual basis. Combining the FMA contracts and CO or AD seasonal exchange contracts provides for a larger reduction of generation during those periods when the PSW returns the power. This allows for the hydro system to use its flexibility so that generation in other months can also be reduced resulting in a larger annual decrease. The combined contracts also reduce the PSW economy energy market so that there are not as many opportunities to sell thermal energy south as under the CO or AD cases individually.

The monthly operational changes still show the expected impacts associated with seasonal exchange contracts. Reduced generation during periods of return and some increase in generation during those periods of delivery. Combining the FMA with CO1/AD1 or CO5/AD5 does not change the monthly differences associated with intertie ownership alternatives. The 52%/48% PUB/IOU split cases still tend to displace fewer CTs during the winter months than the 100% PUB cases. The reasons already noted (see section D.2.2) are not sensitive to whether BPA increases the amount of federal marketing in conjunction with capacity ownership or assured delivery. The reduction in the available market for economy energy sales does change the CT operation differences between the CO and AD cases under conditions of low loads and water. When combined with the FMA case, both the CO and AD cases reduce CT operation under the conditions noted. However, it is still the case that CT operation under those conditions is less with AD than CO.

For the PSW, there is no difference in the annual operational impact associated with any of the four combined alternatives considered. The PSW remains a net exporter of power to the PNW. When comparing the PSW results in the combined alternatives with the individual cases, it is seen that in all of the four cases the amount of the net export under high loads remains the same as in the individual FMA case. Under low loads, however, the PSW is more of a net exporter than under any of the other cases when treated separately. The combined exchange and FMA contracts reduce the market for economy energy sales during delivery to the PSW and increase displacement opportunities during return from the PSW to such an extent that the month to month sales to and returns from the PSW are considerably larger than under any of the individual cases. Combining FMA with CO or AD does not alter the monthly variations in service to the PSW market noted in the individual cases. There are still larger changes in sales to the PSW on a monthly basis in the CO cases than the AD cases and these differences still disappear on an annual average basis.

BCHs ability to sell power on the spot market to the PNW or the PSW does not change significantly under the combined cases. While quite small, BCH does see more variation in sales on an annual average basis under the AD cases

than under the CO cases. This result is not different from that seen in the individual cases and would lead to the conclusion that capacity ownership or assured delivery combined with federal marketing has little effect on BCHs ability to sell in the economy energy market.

Power Sale Alternatives

The power sales (PS) alternatives include the federal marketing case B (FMB) and the capacity ownership (CO) cases with the intertie allocated 100 percent to the PUBs (CO1) and cases with the intertie allocated 52 percent to the PUBs and 48 percent to the IOUs (CO5). This grouping also includes combinations of FMB and CO1 and CO5. Because there is no difference between the SAM modeling of the firm contract under CO and AD conditions, the AD cases were not necessary to consider. The results associated with the CO cases apply to the AD cases (see section D.2.3).

Federal Marketing Case B (FMB)

The FMB case is a companion to the FMA case. Both cases assess the impacts associated with increased federal marketing over the intertie. The FMA case considered contracts and operating strategies that were placed entirely upon the federal system. The attempt there was to create a combination of contracts that would appeal to the PSW and provide BPA with the opportunity to sell the increased fish related water. The design of the FMB case is based on a joint venture type of contract. It is assumed that some entity other than BPA wants to access the PSW with a firm annual contract. In providing access to the intertie, BPA joins in the agreement and supplies the firm contract to the PSW during the May and June and requests that the energy delivered during those months be returned to BPA in equal amounts from October through March. This portion of the agreement is the same as that included in the FMA case and it allows BPA sell the fish related water flows during May and June and have them returned during a period of greater need. The PSW gets a firm contract all year and needs to return the power received during May and June during off peak periods. While the FMB case is not strictly a firm power sale, it resembles one in many aspects and is, therefore, included in the firm power sale discussion.

Operational impacts for the FMB case are provided in Table 11. These results need to be considered in light of the resource assumptions included in the FMB case. The entity requesting access to the intertie was not identified in this case and no resource acquisition assumptions were made for the SAM modeling. Joint venture proposals could come from entities outside of the region, such as BCH, or from inside the region. The resources used to supply these contracts could be resources that, from a regional standpoint, would not be considered dispatchable. Cogeneration resources, for example, are considered by the SAM to be non-dispatchable or unable to be controlled by the generation system.

Resources based in another region would also not be dispatchable. The 1100 aMW joint venture contract assumed in the FMB case represents a potentially large number of smaller joint venture contracts served with a variety of different resources. The intent of the FMB case is to assess the impact on the region of giving up access to 1100 aMW of intertie capacity that is currently available for economy energy transactions and to consider the impact on the region due to the reduced market for regional power. The FMB case also considers the impact associated with the marketing and return of fish related flows on the regional hydro system.

The return of the energy from the PSW and the loss in economy sales due to the smaller market available for economy energy causes a general reduction in the annual average energy generated in the PNW. Reduced generation is noticed generally in all months except May and June. Under conditions of low water there is an increase in CT generation during June that could be related to the sale by BPA. It could also be related to the fact that the economy energy sales to the PSW do not reduce by a full 1100 aMW and some of the CT operation could be used to serve sales to the PSW. With the assumed high valued PSW market, the latter case is most likely.

The, PSW becomes a net importer with the delivery of an 1100 aMW contract. There is a reduction in economy energy sales on an annual basis under both high and low loads. The reduction in economy energy sales is larger under low loads because she region has a surplus and the smaller available market means that less of the surplus can be sold. Under conditions of high loads there is less economy energy to sell so the smaller market has less of an impact.

Once again, the alternative creates little impact upon BCH. There is an overall reduction in the sales of economy energy on an annual basis under both low and high loads. Because of the surplus in the PNW under low loads and the reduced PSW market, BCH takes the greatest loss in sales to the PSW under conditions of low loads.

Capacity Ownership (CO)

The capacity ownership case transferred 725 MW of intertie capacity to non-Federal owners. The allocation alternatives were 100% to the PUB (CO1) and 52%/48% PUB/IOU, respectively (CO5). In the power sale case, the allocation of the intertie for each group (CO1 and CO5) was filled with a firm power contract delivered 12 months a year, 24 hours a day. The contract was assumed to be served with the addition of a generic CT equal in size to the contract.

Tables 12 and 13 present the SAM results for the CO1 and CO5 cases. A comparison indicates that there are no significant differences between CO1 and

CO5 on an annual average basis. Under high loads there is a slight increase in hydro generation and about a 20 percent increase in CT generation compared to the NA case. The increase in CT generation is evident in both cases under all load and water conditions. This increase is related to serving the new firm contract. The increase is greater in the CO5 case than the CO1 case for the same ownership and rate limitation reasons that these cases varied in the SE cases (see section D.2.2). Under low loads there is a decrease in hydro generation on an annual basis. BPA prices the firm surplus in the low load case at the firm surplus rate. The projections of the surplus firm rate included in the SAM are somewhat above the operating cost of the new high efficient CTs added to serve the additional load. Consequently, the increased load is served with additional CT operation that is not displaced by hydro generation because it has a higher cost. Another reason for this reduction in hydro generation is due to the reduction in the PSW market resulting from the firm contracts and the loss

The impact on the PSW is similar to that under the FMB case. The PSW becomes a net importer under both high and low loads because of the firm contract. While there is a reduction in economy energy sales because of the reduced market, the reduction is less than the additional amount delivered under contract. It is also the case in this alternative that the loss in economy energy sales is greater under low loads because the reduced market causes more of an effect when the region is surplus. The differences in economy energy sales between the CO1 and CO5 cases are not as large as those occurring in the SE cases. It is still the case however, that more economy energy is sold to the PSW under CO5 than CO1 reflecting resource ownership of the participants.

Because of the increase in PNW firm load, there is increased opportunity for economy energy sales from BCH. There is a slight increase in sales by BCH to the PNW. However, the reduced availability of the PSW economy energy market causes BCH to reduce sales to the PSW. Both of these changes are relatively small.

Alternative Combinations

Those alternatives representing combinations of CO and the FMB cases were studied with the SAM. These combinations (FMBCO1 and FMBCO5) consider the operational effects of combining increased federal marketing with increased nonfederal use of the intertie.

Results for these two combinations are presented in Tables 14 and 15. These combinations of contract types show the largest impact of any of the NFPeis alternatives considered. The combined joint venture and power sale contracts reduce the PSW market by 1825 aMW during months of delivery and this amount is reduced by 445 aMW when the PSW returns to BPA its portion of the

joint venture contract. In both alternatives there is a reduction in hydro and coal generation and an increase in CT generation under both load forecast sensitivities. Hydro and coal generation is reduced because of the reduced PSW market. Under low loads, the reduction is larger because of the surplus situation. Resources normally sold to the PSW are not operated because the market has declined. CT operation increases in all cases. This result is due to the low cost of new high efficiency gas fired combined cycle combustion turbines. The PSW market is still favorable to a low cost resource such as that. The new CT is lower cost than some of the existing high cost coal facilities in the region. This is why coal displacement occurs and CT generation increases relative to the NA case. Compared with the CO cases considered above, CT generation is less. This is also due to the larger market reduction in these cases.

In both cases, the PSW is a net importer of power. There are reductions in the amount of economy energy sold to the PSW. As before, this reduction is larger for the low loads case and where the intertie is allocated entirely to the PUBs. The largest reduction in economy energy sales occurs during May and June. This reduction is still less than the total change in deliveries to the PSW. During those months, there is an increase in generation in the PNW that is used to serve the contracts and the economy energy contracts. As before, it is likely that some portion of the increase was to support the sale of fish related flows by BPA.

Economy energy sales to the PNW by BCH have increased under both load sensitivities for both combinations. The increased load in the PNW creates a larger market for BCH sales. The reduced PSW market however, reduces BCHs ability to sell. Consequently, there is a reduction in sales by BCH to the PSW. There is no significant difference in BCH sales to either market associated with either of the two cases considered.

Combined Seasonal Exchange (SE)/Power Sale (PS) Alternatives

This section considers six additional combinations of alternatives. These alternatives were also constructed because of the likelihood that BPA will pursue some combination of the federal marketing alternative and the capacity ownership or assured delivery alternatives. The first group combines the federal marketing case A with the capacity ownership alternative with a firm power sale (FMACO1 and FMACO5). The second group combines the federal marketing case B with the capacity ownership cases with seasonal exchange contracts (FMBCO1, FMBCO5), and the third group combines the federal marketing case B with assured delivery cases-with seasonal exchange contracts (FMBAD1, and FMBAD5).

Federal Marketing Case A With Capacity Ownership; Power Sale

The assured delivery case is not considered in this combination separately because the assured delivery case is no different than the capacity ownership cases with respect to the modeling in the SAM (see section D.2.3).

The SAM generated operational impacts for these two alternatives are presented in Tables 16 and 17. Because of the addition of the relatively inexpensive CT to serve the increase in firm load, the combined FMACO cases more closely resemble the CO case than the FMA case. In both load scenarios, over both cases, there is an increase in CT generation and a reduction in coal and hydro operation on an annual average basis. The reductions in coal and hydro generation are slightly greater than that in the CO cases and the increase in CT generation is less than in the CO cases. The addition of the seasonal exchange characteristics of the FMA contracts lessens the need for increased CT generation. On a month by month basis, the returns to BPA from the PSW tend to create changes in hydro and coal generation that resemble the FMA changes under high loads. Under low loads, the returns and the reduced PSW market, combined with the inexpensive CT, causes much larger monthly variation in hydro and coal generation. CT generation does not vary from the monthly pattern seen in the CO cases. In May and June, the FMACO cases see an increase in generation over both the FMA case or the CO cases. This increase is related to the addition of the firm contract combined with the fish flow related firm contract in the FMA case.

The impact on the PSW is similar to that under the CO case. The PSW becomes a net importer under both high and low loads on an annual average basis because of the firm contract. With the seasonal exchange returns, there are months where the PSW is a net exporter While there is a reduction in economy energy sales because of the reduced market, the reduction is less than the additional amount delivered under contract. It is also the case that the loss in economy energy sales is greater under low loads because the reduced market causes more of an effect when the region is surplus. It is still the case, however, that more economy energy is sold to the PSW under FMACO5 than FMACO1, reflecting resource ownership of the participants.

Under high loads, BCH sees a small reduction in sales to the PNW and virtually no change in sales to the PSW on an annual average basis. Under low loads, the change in BCH economy energy sales to the PNW and the PSW is almost identical to those that occurred in the CO cases with power sales contracts.

Federal Marketing Case B With Capacity Ownership; Seasonal Exchange

Tables 18 and 19 provide the SAM results from the FMBCO1 and FMBCO5 cases. Similar to the other alternatives considered, there is very little difference

between the two cases on an annual average basis. Both cases experience a reduction in all types of resource generation under both load sensitivities because of the large reduction in the PSW market due to the added contracts and the return of energy associated with the BPA portion of the joint venture contract. The decrease is larger under low loads because of the surplus. The change in annual PNW generation in the combined case is almost identical to the sum of the changes in the individual alternatives. This implies that there are no additional impacts due to any interaction between the alternatives. Monthly variations in generation are also similar to those experienced in the individual FMB and CO seasonal exchange cases when added together. Generation tends to decrease during the winter months due to the return of energy and the reduced market and increases during the spring and summer because of the delivery of energy to the PSW.

The PSW remains a net importer under either load forecast. There is a reduction in the sales of economy energy with the reduction being more pronounced in the low loads case. This is again related to the sensitivity of economy energy sales during periods of surplus. Monthly impacts on the PSW market also match the combined impacts of the CO seasonal exchange cases and the FMB case. There is an increase in economy energy sales during the winter months when the energy is returned to the PNW from the PSW. This increase is greater in the high load case than in the low load case and the effect is larger in the FMBCO5 case than in the FMBCO1 case. Economy energy sales decrease during the spring and summer when energy delivered is sent under firm contract instead of as economy energy sales as in the NA case. The reduction in economy energy sales during May and June is less than the increase in the firm contracts. Consequently, there is an increase in generation used to serve the 1100 aMW of joint venture sales and the 725 aMW exchange contract.

Due to the changed load situation in the PNW and the reduction in the PSW economy energy market, BCH is able to increase its economy energy sales to the PNW and decreases sales to the PSW. This result is the same under both load forecasts and is also approximately equal in effect to the sum of the individual CO and FMA cases.

Federal Marketing Case B With Assured Delivery; Seasonal Exchange

The SAM results for the FMBAD1 and FMBAD5 seasonal exchange combined cases are listed in Tables 20 and 21. The differences between the two cases are negligible on an annual average basis. There is a reduction in PNW generation in both cases over both load scenarios. There is slightly more CT generation in the 52%/48% PUB/IOU allocation case than in the 100% PUB intertie allocation case. This result varies with the load forecast and is most visable on a monthly basis. Under high loads, during the winter months when

the seasonal exchange energy and the energy to BPA associated with the joint venture contract is returned, more resource displacement occurs in the 100%

PUB case. Given BPAs rate limitations for sales south and regional preference, displacement represents the greater value use for the energy. Under the 52%/48% PUB/IOU allocation case, energy returned to the IOUs increases the amount they have to market. Given that the IOUs are not rate constrained, they tend to market more of the power to the PSW and there are fewer resources displaced. Under low loads, the region is surplus with most of the surplus residing on the federal system. The market to the PSW is fairly full such that the additional energy returned to the system is not readily salable to the PSW and is used for displacement purposes. Consequently, there is practically no difference in regional generation between the 52%/48% PUB/IOU allocation case and the 100% PUB intertie allocation case under low loads. This result is also related to the fact that the FMB contracts have significantly reduced the available economy energy market. This result is also evident in the FMBCO cases described above and supports the differences between FMBCO1 and FMBCO5.

There are essentially no annual average differences between these two FMBAD cases and the FMBCO cases discussed above. There is a slightly lower amount of generation in the FMBAD cases than in the FMBCO cases. This difference is based on the potentially larger amounts of total intertie allocation available under the CO cases than under the AD cases. These differences are more noticeable on a monthly basis. During the winter, there are months where generation in the CO case is higher than that in the AD case and there is an associated increase in economy energy sales to the PSW. The results indicate that under the FMBAD cases, resource displacement and sales to the PSW tend to vary with the intertie allocation between parties. This is also the case for the FMBCO cases but, the ownership option causes the variation in resource operation and displacement to be even larger than that under the FMBAD cases.

The PSW remains a net importer under either load forecast. There is a reduction in the sales of economy energy with the reduction being more pronounced in the low loads case. This is again related to the sensitivity of economy energy sales during periods of surplus. Given the above discussion, it is no surprise that the reduction in spot market sales to the PSW is greater in the FMBAD cases than in the FMBCO cases under conditions of high loads. Under low loads, service to the PSW is essentially the same between the FMBAD cases and the FMBCO cases.

Due to the changed load situation in the PNW and the reduction in the PSW economy energy market, BCH is able to increase its economy energy sales to the PNW only under low loads. In all other cases there is a reduction in sales by BCH to the PSW and the PNW. This change is small, however.

Summary

Seasonal Exchange Alternatives

Annual average operational impacts associated with the seasonal exchange contract for each alternative are summarized in Charts 1-4. Under high loads, PNW CT operation decreases from 12 to 128 aMW. The range in PNW coal generation is from no change to a decline of 19 aMW. Regional hydro generation ranges from a decrease of 6 aMW to an increase of 7 aMW. Total sales to the PSW are reduced from 21 to 169 aMW. Economy energy sales from BCH range from a 5 aMW increase to a 13 aMW decline.

Under low loads, PNW resource operation still does not change by much. PNW CT generation ranges from an increase of 9 aMW to a decrease of 22 aMW. The reduction in PNW coal generation ranges between 15 to 79 aMW. Hydro generation decreases from 13 to 34 aMW. Total sales to the PSW are reduced from 56 to 147 aMW and economy energy sales from BCH range from a positive 13 aMW to a negative 29 aMW.

On an operational basis, these results indicate that seasonal exchange contracts tend to reduce PNW generation, reduce total sales to the PSW, thus, increasing their generation, and, generally reduces the amount of economy energy sold by BCH. The magnitude of these changes is relatively small. The results indicate that while there are different impacts associated with each alternative, no single alternative creates impacts that are significantly larger than any other alternative. There are no interactions that occur when the cases are combined. The combined results are basically the sum of the individual cases.

Power Sales Alternatives

The annual average operational results from the power sales cases are summarized in Charts 5 - 8. These cases are not strictly comparable because of the resource differences between FMB and the CO cases. The FMB case did not include any additional generation to serve the new 1100 aMW load while the CO cases assumed that the 725 aMW additional load was served with a generic combined cycle combustion turbine.

Under high loads, the FMB case created within the PNW a 130 aMW reduction in CT operation, a 58 aMW reduction in coal operation, and an 8 aMW reduction in hydro operation compared to the NA case. Because of the 1100 aMW firm sale, the PSW became a net importer of 714 aMW and BCH saw a 9 aMW reduction in economy sales. Under low loads, the FMB case created within the PNW a 30 aMW reduction in CT operation, a 174 aMW reduction in coal operation, and a 167 aMW reduction in hydro operation. The PSW remained a net importer of 532 aMW and BCH saw a 48 aMW reduction in economy sales.

While there was no assumed increase in generation to serve the increased load, the FMB results are still relevant. Potential joint venture contracts with BPA could be signed with entities from outside the region (such as BCH). The generation used to serve these contracts would not be part of the regional resource base and as such may not be displaceable with any regional resources with lower cost. If this were the case, resource operational changes in the PNW would be related to reductions in the economy energy market in the PSW due to the additional firm contract. This is the situation under the FMB case. If the resource used to serve the joint venture contract was inside the region, but, had operational characteristics such that the resource was not controllable, the results of the FMB case would also apply. Resources with these characteristics could be, for example, conservation or cogeneration associated with a production process that operates all day, all year around. Output from the cogeneration resource is related to business operation and not necessarily related to the hourly or monthly generation needs of a power system. In terms of the SAM modeling, the output from non-dispatchable resources is treated simply as a load reduction and the dispatchable resources are then used to serve the remaining load. Consequently, the SAM related results would not change.

For the CO and combined FMB/CO cases, CT generation increased because of the additional resource used to serve the additional load. Under high loads, PNW CT operation increases ranged from 288 to 454 aMW. The range in PNW coal generation is from an increase of 6 aMW to a decline of 72 aMW. Regional hydro generation ranges from a decrease of 8 aMW to an increase of $ aMW. Due to the large export contracts to the PSW, total sales to the PSW increase from 431 to 1222 aMW. Economy energy sales from BCH decrease from 7 to 27 aMW. Under low loads, PNW CT generation increases 209 to 311 aMW. The reduction in PNW coal generation ranges between 22 to 219 aMW. Hydro generation decreases between 60 to 249 aMW. Total sales to the PSW increase from 204 to 768 aMW and economy energy sales from BCH decrease 27 to 75 aMW.

On an operational basis, the power sales cases see an increase in the generation of the resource assumed to be acquired to serve the contract. The increased operation is less than the full contract amount since some displacement occurs. The variation in the results is directly related to the resource assumptions included in each of the cases. As with the seasonal exchange cases, the combined results are basically the sum of the individual cases.

Combined Seasonal Exchange (SE)/Power Sale (PS) Alternatives

The results for those cases that combined the SE and PS contract types are summarized in Charts 9 - 12. Once again, the combined impacts are approximately the same as the sum of the individual cases. For the federal marketing case A combined with capacity ownership and power sales contracts, PNW CT operation increased over both high and low loads, ranging from 256 to 347 aMW. This increase was again related to the addition of the low cost combined cycle CT. Both coal and hydro generation in the PNW was reduced under both load forecasts. The reduction ranged from 7 to 44 aMW for coal and from 7 to 75 aMW for hydro. Net export sales to the PSW increased, ranging from 207 to 393 aMW and economy energy sales from BCH decreased, ranging from 2 to 26 aMW.

For those cases that combined the federal marketing case B with capacity ownership or increased assured delivery and seasonal exchange contracts, PNW generation was decreased in all cases. Hydro generation decreases ranged from 1 to 213 aMW, coal generation decreases ranged from 59 to 243 aMW, and CT generation decreases ranged from 23 to 159 aMW. These reductions are related to the loss of available PSW market due to the large contract assumed in the FMB case and to resource displacement resulting from the energy returned to BPA during the winter as part of the joint venture contract.
Net export sales to the PSW increased, ranging from 399 to 698 aMW and economy energy sales from BCH decreased, ranging from 13 to 82 aMW.

Table F-7 Table 1 No Action Case Operation - 20 Year Averages - Average MW

PNW Generation	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads													
Ave Water Hydro	10793	11937	13268	16668	18910	18700	19679	20113	22654	21346	17531	13113	17059
Coal	5596	5653	5008	5719	5685	5606	4960	3778	3102	4012	4939	5707	5030
CT	3753	3663	3597	2818	2422	2320	1577	1355	42	690	1447	3188	2239
High Water Coal	5601	5644	5607	5721	5714	5710	4623	3442	2240	1794	3999	5733	4652

CT	4077	2710	2606	1975	1784	1690	760	408	0	0	101	2112	1518
Low Water Coal	5601	5666	5615	5750	5750	5750	5496	4572	4077	5326	5749	5750	5425
CT	4137	4079	4313	3895	4392	4432	4179	3918	153	2539	3963	4341	3695
Low Loads													
Ave Water Hydro	12300	13054	15117	16604	18377	18028	17518	17885	20207	19091	16761	12835	16482
Coal	4352	4352	4195	4183	3983	3616	2996	2064	1283	1865	2691	4248	3319
CT	268	238	157	170	216	155	166	186	0	6	119	352	169
High Water Coal	4551	3595	3840	3875	3824	3336	2324	1376	861	972	973	3610	2761
CT	272	33	9	27	8	1	0	0	0	0	0	38	32
Low Water Coal	4595	4578	4574	4687	4774	4772	4520	3627	2698	3983	4769	4772	4362
CT	340	357	328	372	1222	1003	963	981	0	29	816	1011	619
Sales to PSW													
High Loads													
Economy Energy	1391	1725	1741	2503	2840	3485	3680	4091	4417	4622	3860	2302	3054
Net Export Sales	1391	1725	1741	2503	2840	3485	3680	4091	4417	4622	3860	2302	3054
Low Loads													
Economy Energy	3355	3656	4391	4728	5621	5824	5327	5038	6296	5625	5138	3787	4900
Net Export Sales	3355	3656	4391	4728	5621	5824	5327	5038	6296	5625	5138	3787	4900
BCH Sales South													
High Loads													
PNW	234	188	251	51	244	238	91	407	285	383	396	344	260
PSW	290	223	217	130	103	173	58	164	70	127	206	510	189
Low Loads													
PNW	140	74	109	59	151	244	159	170	38	62	67	275	129
PSW	333	272	231	140	78	124	76	77	4	13	110	612	172

Table F-8 Table 2: Federal Marketing Case A Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	11153	11863	13381	16505	18684	18623	19716	20071	22688	21416	17392	13137	17053
	Coal	5596	5647	5607	5701	5680	5558	4849	3667	3170	3974	5001	5703	501
	CT	3653	3443	3362	2570	2377	2147	1424	1303	53	741	1513	3133	2143

High Water	Coal	5601	5649	5602	5696	5713	5663	4365	3324	2199	1770	4128	5731	4620
	CT	3934	2478	2309	1809	1695	1533	453	288	0	0	135	2055	1391
Low Water	Coal	5601	5666	5615	5748	5750	5750	5496	4573	4082	5326	5750	5750	5425
	CT	4026	3899	4127	3659	4374	4414	4208	3967	195	2893	3970	4331	3672
Low Loads														
Ave Water	Hydro	12703	12846	14950	16523	18424	18023	17401	17943	20165	19045	16766	12838	16469
	Coal	4307	4338	4150	4172	3970	3595	2972	2042	1274	1879	2700	4249	3304
	CT	215	210	136	141	185	137	139	182	0	11	121	358	153
High Water	Coal	4483	3644	3646	3893	3813	3329	2333	1357	861	1001	973	3618	2746
	CT	245	29	5	28	0	0	0	0	0	0	0	39	29
Low Water	Coal	4542	4538	4536	4609	4775	4774	4521	3626	2687	4019	4775	4772	4348
	CT	281	318	282	275	1163	927	814	919	0	63	812	1020	573
Sales to PSW														
High Loads														
Economy Energy		1601	2011	2195	2707	3171	3700	4060	3916	3628	3780	3857	2257	3071
Net Export Sales		1601	1331	1515	2027	2491	3020	3380	3916	4728	4880	3857	2257	2914
Low Loads														
Economy Energy		3609	3986	4782	5185	6181	6362	5874	5063	5347	4697	5146	3783	5001
Net Export Sales		3609	3306	4102	4505	5501	5682	5194	5063	6447	5797	5146	3783	4844
BCH Economy Sales South														
High Loads														
	PNW	175	160	193	68	223	206	120	456	267	382	396	347	250
	PSW	320	245	271	144	132	188	49	114	61	124	215	505	197
Low Loads														
	PNW	137	56	138	50	147	257	277	171	33	65	60	279	139
	PSW	303	281	251	153	86	137	110	69	4	12	104	591	175

Table F-9 Table 2-A: Federal Marketing Case A Operation - Percentage Change From No Action Case

		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	3.3	-0.6	0.9	-1.0	-1.2	-0.4	0.2	-0.2	0.2	0.3	-0.8	0.2	0.0
	Coal	0.0	-0.1	0.0	-0.3	-0.1	-0.9	-2.2	-2.9	2.2	-0.9	1.3	-0.1	-0.3

```
            CT       -2.7     -6.0     -6.5   -8.8   -1.9   -7.5   -9.7   -
3.8   26.2    7.4    4.6   -1.7  -4.3
High Water  Coal      0.0      0.1     -0.1   -0.4    0.0   -0.8   -5.6   -
3.4   -1.8   -1.3    3.2    0.0  -0.7
            CT       -3.5     -8.6    -11.4   -8.4   -5.0   -9.3  -40.4  -
29.4    0.0    0.0   33.7   -2.7  -8.4
Low Water   Coal      0.0      0.0      0.0    0.0    0.0    0.0    0.0
0.0    0.1    0.0    0.0    0.0   0.0
            CT       -2.7     -4.4     -4.3   -6.1   -0.4   -0.4    0.7
1.3   27.5   13.9    0.2   -0.2  -0.6
Low Loads
Ave Water   Hydro     3.3     -1.6     -1.1   -0.5    0.3    0.0   -0.7
0.3   -0.2   -0.2    0.0    0.0  -0.1
            Coal     -1.0     -0.3     -1.1   -0.3   -0.3   -0.6   -0.8   -
1.1   -0.7    0.8    0.3    0.0  -0.5
            CT      -19.8    -11.8    -13.4  -17.1  -14.4  -11.6  -16.3   -
2.2    0.0   83.3    1.7    1.7  -9.5
High Water  Coal     -1.5      1.4     -5.1    0.5   -0.3   -0.2    0.4   -
1.4    0.0    3.0    0.0    0.2  -0.5
            CT       -9.9    -12.1    -44.4    3.7 -100.0 -100.0    0.0
0.0    0.0    0.0    0.0    2.6  -9.4
Low Water   Coal     -1.2     -0.9     -0.8   -1.7    0.0    0.0    0.0
0.0   -0.4    0.9    0.1    0.0  -0.3
            CT      -17.4    -10.9    -14.0  -26.1   -4.8   -7.6  -15.5   -
6.3    0.0  117.2   -0.5    0.9  -7.4
Sales to PSW
High Loads
Economy Energy       15.1     16.6     26.1    8.2   11.7    6.2   10.3   -
4.3  -17.9  -18.2   -0.1   -2.0   0.6
Net Export Sales     15.1    -22.8    -13.0  -19.0  -12.3  -13.3   -8.2   -
4.3    7.0    5.6   -0.1   -2.0  -4.6
Low Loads
Economy Energy        7.6      9.0      8.9    9.7   10.0    9.2   10.3
0.5  -15.1  -16.5    0.2  .-0.1   2.1
Net Export Sales      7.6     -9.6     -6.6   -4.7   -2.1   -2.4   -2.5
0.5    2.4    3.1    0.2   -0.1  -1.1
BCH Economy Sales South
High Loads
            PNW     -25.2    -14.9    -23.1   33.3   -8.6  -13.4   31.9
12.0   -6.3   -0.3    0.0    0.9  -3.8
            PSW      10.3      9.9     24.9   10.8   28.2    8.7  -15.5  -
30.5  -12.9   -2.4    4.4   -1.0   4.2
Low Loads
            PNW      -2.1    -24.3     26.6  -15.3   -2.6    5.3   74.2
0.6  -13.2    4.8  -10.4    1.5   7.8
            PSW      -9.0      3.3      8.7    9.3   10.3   10.5   44.7  -
10.4    0.0   -7.7   -5.5   -3.4   1.7
```

Table F-10 Table 2-B: Federal Marketing Case A Operation - Average MW Change From No Action Case

```
PNW Generation        SEP      OCT      NOV    DEC    JAN    FEB    MAR
APR    MAY    JUN    JUL    AUG   AVE
High Loads
Ave Water   Hydro     360      -74      113   -163   -226    -77     37    -
42     34     70   -139     24    -6
            Coal        0       -6       -1    -18     -5    -48   -111    -
111    68    -38     62     -4   -17
```

CT -100 -220 -235 -248 -45 -173 -1153 -
52 11 51 66 -55 -96
High Water Coal 0 5 -5 -25 -1 -47 -258 -
118 -41 -24 129 -2 -32
CT -143 -232 -297 -166 -89 -157 -307 -
120 0 0 34 -57 -127
Low Water Coal 0 0 0 -2 0 0 0
1 5 0 1 0 0
CT -111 -180 -186 -236 -18 -18 -29
49 42 354 7 -10 -23
Low Loads
Ave Water Hydro 403 -208 -167 -81 -47 -5 -117
58 -42 -46 5 3 -13
Coal -45 -14 -45 -11 -13 -21 -24 -
22 -9 14 9 1 -15
CT -53 -28 -21 -29 -31 -18 -27
-4 0 5 2 6 -16
High Water Coal -68 49 -194 18 -11 -7 9 -
19 0 29 0 8 -15
CT -27 -4 -4 1 -8 -1 0
0 0 0 0 1 -3
Low Water Coal -53 -40 -38 -78 1 2 1
-1 -11 36 6 0 -14
CT -59 -39 -46 -97 -59 -76 -149 -
62 0 34 -4 9 -46
Sales to PSW
High Loads
Economy Energy 210 286 454 204 331 215 380 -
175 -789 -842 -3 -45 17
Net Export Sales 210 -394 -226 -476 -349 -465 -300 -
175 311 258 -3 -45 -140
Low Loads
Economy Energy 254 330 391 457 560 538 547
25 -949 -928 8 -4 10
Net Export Sales 254 -350 -289 -223 -120 -142 -133
25 151 172 8 -4 -56
BCH Economy Sales South
High Loads
PNW -59 -28 -58 17 -21 -32 29
49 -18 -1 0 3 -10
PSW 30 22 54 14 29 15 -9 -
50 -9 -3 9 -5 8
Low Loads
PNW -3 -18 29 -9 -4 13 118
1 -5 3 -7 4 10
PSW -30 9 20 13 8 13 34
-8 0 -1 -6 -21 3

Table F-11 Table 3: Capacity Ownership - 100% PUB - Seasonal Exchange - Operation - 20 Year Averages - Average MW

PNW Generation SEP OCT NOV DEC JAN FEB MAR
APR MAY JUN JUL AUG AVE
High Loads
Ave Water Hydro 11143 11935 13140 16597 18534 18471 19785
20189 22717 21406 17607 13261 17065

	Coal	5597	5652	5607	5706	5673	5572	4963	3738	3097	4057	4989	5711	5030
	CT	3820	3654	3404	2517	2387	2173	1555	1317	43	727	1579	3383	2213
High Water	Coal	5601	5646	5602	5718	5712	5676	4603	3418	2208	1782	4141	5736	4654
	CT	4090	2722	2311	1882	1709	1538	820	380	0	0	132	2375	1496
Low Water	Coal	5601	5666	5615	5749	5750	5750	5496	4572	4082	5326	5749	5750	5426
	CT	4164	4091	4200	3501	4390	4425	4157	3879	1611	2808	4046	4343	3680
Low Loads														
Ave Water	Hydro	13078	12970	14589	16100	18292	17737	17693	18046	20230	19083	16821	12919	16453
	Coal	4296	4384	4191	4172	3755	3457	2927	1986	1272	1850	2670	4268	3269
	CT	215	310	166	189	185	150	178	202	0	11	129	402	178
High Water	Coal	4487	3628	3630	3875	3491	3288	2159	1325	861	972	973	3613	2692
	CT	253	30	2	29	0	0	0	0	0	0	0	42	29
Low Water	Coal	4544	4637	4626	4707	4772	4772	4518	3623	2654	4001	4783	4777	4368
	CT	267	443	386	442	1205	1028	1028	1031	0	49	828	1046	646
Sales to PSW														
High Loads														
Economy Energy		1227	1775	2004	2744	3002	3598	3785	4103	4458	4094	3452	1981	3016
Net Export Sales		1880	1775	1352	2092	2350	2946	3785	4103	4458	4747	4105	2634	3016
Low Loads														
Economy Energy		3333	3649	4451	4847	5899	5957	5383	5111	6309	4991	4536	3271	4811
Net Export Sales		3986	3649	3799	4195	5247	5305	5383	5111	6309	5644	5189	3924	481
BCH Economy Sales South														
High Loads														
	PNW	303	288	259	93	240	214	104	454	282	355	375	365	279
	PSW	273	186	171	87	63	144	35	113	50	113	184	475	157
Low Loads														
	PNW	185	150	151	61	155	253	153	194	41	76	65	291	147
	PSW	258	168	142	79	43	45	34	36	4	11	99	575	125

Table F-12 Table 3-A: Capacity Ownership - 100% PUB- Seasonal Exchange - Percentage Change From No Action Case

PNW Generation	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads													

Ave Water	Hydro	3.2	0.0	-1.0	-0.4	-2.0	-1.2	0.5	0.4	0.3	0.3	0.4	1.1	0.0
	Coal	0.0	0.0	0.0	-0.2	-0.2	-0.6	0.1	-1.1	-0.2	1.1	1.0	0.1	0.0
	CT	1.8	-0.2	-5.4	-10.7	-1.4	-6.3	-1.4	-2.8	2.4	5.4	9.1	6.1	-1.2
High Water	Coal	0.0	0.0	-0.1	-0.1	0.0	-0.6	-0.4	-0.7	-1.4	-0.7	3.6	0.1	0.0
	CT	0.3	0.4	-11.3	-4.7	-4.2	-9.0	7.9	-6.9	0.0	0.0	30.7	12.5	-1.4
Low Water	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
	CT	0.7	0.3	-2.6	-10.1	0.0	-0.2	-0.5	-1.0	5.2	10.6	2.1	0.0	-0.4
Low Loads														
Ave Water	Hydro	6.3	-0.6	-3.5	-3.0	-0.5	-1.6	1.0	0.9	0.1	0.0	0.4	0.7	-0.1
	Coal	-1.3	0.7	-0.1	-0.3	-5.7	-4.4	-2.3	-3.8	-0.9	-0.8	-0.8	0.5	-1
	CT	-19.8	30.3	5.7	11.2	-14.4	-3.2	7.2	8.6	0.0	83.3	8.4	14.2	5.3
High Water	Coal	-1.4	0.9	-5.5	0.0	-8.7	-1.4	-7.1	-3.7	0.0	0.0	0.0	0.1	-2.5
	CT	-7.0	-9.1	-77.8	7.4	-100.0	-100.0	0.0	0.0	0.0	0.0	0.0	10.5	-9.4
Low Water	Coal	-1.1	1.3	1.1	0.4	0.0	0.0	0.0	-0.1	-1.6	0.5	0.3	0.1	0.1
	CT	-21.5	24.1	17.7	18.8	-1.4	2.5	6.7	5.1	0.0	69.0	1.5	3.5	4.4
Sales to PSW														
High Loads														
Economy Energy		-11.8	2.9	15.1	9.6	- 5.7	3.2	2.9	0.3	0.9	-11.4	-10.6	-13.9	-12
Net Export Sales		35.1	2.9	-22.4	-16.4	-17.3	-15.5	2.9	0.3	0.9	2.7	6.3	14.4	-1.2
Low Loads														
Economy Energy		-0.7	-0.2	1.4	2.5	4.9	2.3	1.1	1.4	0.2	-11.3	-11.7	-13.6	-1.8
Net Export Sales		18.8	-0.2	-13.5	-11.3	-6.7	-8.9	1.1	1.4	0.2	0.3	1.0	3.6	-1.8
BCH Economy Sales South														
High Load														
	PNW	29.5	53.2	3.2	82.4	-1.6	-10.1	14.3	11.5	-1.1	-7.3	-5.3	6.1	7.3
	PSW	-5.9	-16.6	-21.2	-33.1	-38.8	-16.8	-39.7	-31.1	-28.6	-11.0	-10.7	-6.9	-16
Low Loads														
	PNW	32.1	102.7	38.5	3.4	2.6	3.7	-3.8	14.1	7.9	22.6	-3.0	5.8	14.0
	PSW	-22.5	-38.2	-38.5	-43.6	-44.9	-63.7	-55.3	-53.2	0.0	-15.4	-10.0	-6.0	-27.3

Table F-13 Table 3-B: Capacity Ownership - 100% PUB - Seasonal Exchange - Average MW Change From No Action Case

PNW Generation			SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads															
	Ave Water	Hydro	350	-2	-128	-71	-376	-229	106	76	63	60	76	148	6
		Coal		-1	-1	-13	-12	-34	3	-40	-5	45	50	4	0
		CT	67	-9	-193	-301	-35	-147	-22	-38	1	37	132	195	-26
	High Water	Coal	0	2	-5	-3	-2	-34	-20	-24	-32	-12	142	3	2
		CT	13	12	-295	-93	-75	-152	60	-28	0	0	31	263	-22
	Low Water	Coal	0	0	0	-1	0	0	0	0	5	0	0	0	1
		CT	27	12	-113	-394	-2	-7	-22	-39	8	269	83	2	-15
Low Loads															
	Ave Water	Hydro	778	-84	-528	-504	-85	-291	175	161	23	-8	60	84	-19
		Coal	-56	32	-4	-11	-228	-159	-69	-78	-11	-15	-21	20	-50
		CT	-53	72	9	19	-31	-5	12	16	0	5	10	50	9
	High Water	Coal	-64	33	-210	0	-333	-48	-165	-51	0	0	0	3	-69
		CT	-19	-3	-7	2	-8	-1	0	0	0	0	0	4	-3
	Low Water	Coal	-51	59	52	20	-2	0	-2	-4	-44	18	14	5	6
		CT	-73	86	58	70	-17	25	65	50	0	20	12	35	27
Sales to PSW															
High Loads															
Economy Energy			-164	50	263	241	162	113	105	12	41	-528	-408	-321	-38
Net Export Sales			489	50	-390	-412	-491	-540	105	12	41	125	245	332	-38
Low Loads															
Economy Energy			-22	-7	60	119	278	133	56	73	13	-634	-602	-516	-89
Net Export Sales			631	-7	-593	-534	-375	-520	56	73	13	19	51	137	-89
BCH Economy Sales South															
High Loads															
		PNW	69	100	8	42	-4	-24	13	47	-3	-28	-21	21	19
		PSW	-17	-37	-46	-43	-40	-29	-23	-51	-20	-14	-22	-35	-32
Low Loads															
		PNW	45	76	42	2	4	9	-6	24	3	14	-2	16	18
		PSW	-75	-104	-89	-61	-35	-79	-42	-41	0	-2	-11	-37	-47

Table F-14 Table 4: Capacity Ownership - 52%/48% PUB/IOU - Seasonal Exchange - Operation - 20 Year Averages - Average MW

PNW Generation	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads													
Ave Water Hydro	11090	11958	13176	16609	18566	18517	19755	20177	22706	21398	17602	13235	17066
Coal	5596	5653	5608	5708	5670	5573	4967	3742	3086	4058	4994	5708	5030
CT	3788	3692	3478	2654	2389	2223	1557	1328	42	719	1521	3328	2227
High Water Coal	5601	5646	5607	5717	5709	5681	4602	3419	2208	1786	4103	5733	4651
CT	4082	2761	2458	1848	1674	1545	798	352	0	0	115	2317	1496
Low Water Coal	5601	5666	5615	5750	5750	5750	5496	4572	4079	5329	5749	5750	5425
CT	4175	4118	4234	3725	4401	4432	4156	3896	155	2753	4012	4319	3698
Low Loads													
Ave Water Hydro	13069	12972	14596	16087	18300	17735	17688	18050	20228	19076	16806	12918	16460
Coal	4297	4373	4181	4161	3751	3462	2931	1979	1274	1854	2672	4261	3266
CT	234	283	154	172	181	142	175	192	0	11	138	419	175
High Water Coal	4489	3629	3633	3872	3493	3285	2158	1321	861	1002	973	3609	2694
CT	270	35	3	28	0	0	0	0	0	0	0	54	32
Low Water Coal	4546	4608	4606	4686	4772	4772	4519	3624	2662	3996	4779	4777	4362
CT	296	407	348	387	1200	985	1019	999	0	48	878	1076	637
Sales to PSW													
High Loads													
Economy Energy	1147	1840	2123	2889	3033	3690	3777	4117	4436	4079	3404	1891	3033
Net Export Sales	1800	1840	1471	2237	2381	3038	3777	4117	4436	4732	4057	2544	3033
Low Loads													
Economy Energy	3335	3617	4448	4832	5907	5965	5387	5102	6310	4989	4531	3277	4811
Net Export Sales	3988	3617	3796	4180	5255	5313	5387	5102	6310	5642	5184	3930	4811
BCH Economy Sales South													
High Loads													
PNW	299	254	235	72	230	201	106	468	287	377	403	387	277
PSW	276	225	210	110	77	159	38	114	47	94	154	445	162
Low Loads													
PNW	208	122	130	60	150	239	154	190	40	77	75	332	147

	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
PSW	226	201	176	105	54	68	41	41	4	9	85	526	128

Table F-15 Table 4-A: Capacity Ownership - 52%/48% PUB/IOU - Seasonal Exchange - Percentage Change From No Action Case

		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	2.8	0.2	-0.7	-0.4	-1.8	-1.0	0.4	0.3	0.2	0.2	0.4	0.9	0.0
	Coal	0.0	0.0	0.0	-0.2	-0.3	-0.6	0.1	-1.0	-0.5	1.1	1.1	0.0	0.0
	CT	0.9	0.8	-3.3	-5.8	-1.4	-4.2	-1.3	-2.0	0.0	4.2	5.1	4.4	-0.5
High Water	Coal	0.0	0.0	0.0	-0.1	-0.1	-0.5	-0.5	-0.7	-1.4	-0.4	2.6	0.0	0.0
	CT	0.1	1.9	-5.7	-6.4	-6.2	-8.6	5.0	-13.7	0.0	0.0	13.9	9.7	-1.4
Low Water	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
	CT	0.9	1.0	-1.8	-4.4	0.2	0.0	-0.6	-0.6	1.3	8.4	1.2	-0.5	0.1
Low Loads														
Ave Water	Hydro	6.3	-0.6	-3.4	-3.1	-0.4	-1.6	1.0	0.9	0.1	-0.1	0.3	0.6	-0.1
	Coal	-1.3	0.5	-0.3	-0.5	-5.8	-4.3	-2.2	-4.1	-0.7	-0.6	-0.7	0.3	-1.6
High Water	CT	-12.7	18.9	-1.9	1.2	-16.2	-8.4	5.4	3.2	0.0	83.3	16.0	19.0	3.6
High Water	Coal	-1.4	0.9	-5.4	-0.1	-8.7	-1.5	-7.1	-4.0	0.0	3.1	0.0	0.0	-2.4
	CT	-0.7	6.1	-66.7	3.7	-100.0	-100.0	0.0	0.0	0.0	0.0	0.0	42.1	0.0
Low Water	Coal	-1.1	0.7	0.7	0.0	0.0	0.0	0.0	-0.1	-1.3	0.3	0.2	0.1	0.0
	CT	-12.9	14.0	6.1	4.0	-1.8	-1.8	5.8	1.8	0.0	65.5	7.6	6.4	2.9
Sales to PSW														
High Loads														
Economy Energy		-17.5	6.7	21.9	15.4	6.8	5.9	2.6	0.6	0.4	-11.7	-11.8	-17.9	-0.7
Net Export Sales		29.4	6.7	-15.5	-10.6	-16.2	-12.8	2.6	0.6	0.4	2.4	5.1	10.5	-0.7
Low Loads														
Economy Energy		-0.6	-1.1	1.3	2.2	5.1	2.4	1.1	1.3	0.2	-11.3	-11.8	-13.5	-1.8
Net Export Sales		18.9	-1.1	-13.6	-11.6	-6.5	-8.8	1.1	1.3	0.2	0.3	0.9	3.8	-1.8
BCH Economy Sales South														
High Loads														
	PNW	27.8	35.1	-6.4	41.2	-5.7	-15.5	16.5	15.0	0.7	-1.6	1.8	12.5	6.5
	PSW	-4.8	0.9	-3.2	-15.4	-25.2	-8.1	-34.5	-30.5	-32.9	-26.0	-25.2	-12.7	-14.3
Low Loads														

		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
	PNW	48.6	64.9	19.3	1.7	-0.7	-2.0	-3.1	11.8	5.3	24.2	11.9	20.7	14.0
	PSW	-32.1	-26.1	-23.8	25.0	-30.8	-45.2	-46.1	-46.8	0.0	-30.8	-22.7	-14.1	-25.6

Table F-16

Table 4-B: Capacity Ownership - 52%/48% PUB/IOU - Seasonal Exchange - Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	297	21	-92	-59	-344	-183	76	64	52	52	71	122	7
	Coal	0	0	0	-11	-15	-33	7	-36	-16	46	55	1	0
	CT	35	29	-119	-164	-33	-97	-20	-27	0	29	74	140	-12
High Water	Coal	0	2	0	-4	-5	-29	-21	-23	-32	-8	104	0	-1
	CT	5	51	-148	-127	-110	-145	38	-56	0	0	14	205	-22
Low Water	Coal	0	0	0	0	0	0	0	0	2	3	0	0	0
	CT	38	39	-79	-170	9	0	-23	-22	2	214	49	-22	3
Low Loads														
Ave Water	Hydro	769	-82	-521	-517	-77	-293	170	165	21	-15	45	83	-22
	Coal	-55	21	-14	-22	-232	-154	-65	-85	-9	-11	-19	13	-53
	CT	-34	45	-3	2	-35	-13	9	6	0	5	19	67	6
High Water	Coal	-62	34	-207	-3	-331	-51	-166	-55	0	30	0	-1	-67
	CT	-2	2	-6	1	-8	-1	0	0	0	0	0	16	0
Low Water	Coal	-49	30	32	-1	-2	0	-1	-3	-36	13	10	5	0
	CT	-44	50	20	15	-22	-18	56	18	0	19	62	65	18
Sales to PSW														
High Loads														
Economy Energy		-244	115	382	386	193	205	97	26	19	-543	-456	-411	-2
Net Export Sales		409	115	-271	-267	-460	-448	97	26	19	110	197	242	-21
Low Loads														
Economy Energy		-20	-39	57	104	286	141	60	64	14	-636	-607	-510	-89
Net Export Sales		633	-39	-596	-549	-367	-512	60	64	14	17	46	143	-89
BCH Economy Sales South														
High Loads														
	PNW	65	66	-16	-21	-14	-37	15	61	2	-6	7	43	17

	PSW	-14	2	-7	-20	-26	-14	-20	-50	-23	-33	-52	-65	-27
Low Loads														
	PNW	-68	48	21	1	-1	-5	-5	20	2	15	8	57	18
	PSW	-107	-71	-55	-35	-24	-56	-35	-36	0	-4	-25	-86	-44

Table F-17

Table 5: Assured Delivery - 100% PUB - Seasonal Exchange - Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	11138	11918	13117	16587	18540	18475	19782	20195	22715	21409	17612	13260	17062
	Coal	5596	5653	5607	5703	5667	5569	4948	3749	3080	4045	4985	5711	5026
	CT	3814	3654	3395	2488	2356	2172	1534	1322	41	724	1568	3385	2204
High Water	Coal	5601	5644	5602	5713	5707	5688	4595	3444	2205	1774	4141	5736	4654
	CT	4088	2729	2294	1825	1669	1543	805	437	0	0	127	2387	1492
Low Water	Coal	5601	5666	5615	5748	5750	5750	5496	4572	4076	5325	5749	5750	5425
	CT	4153	4089	4218	3495	4390	4427	4139	3871	154	2820	4033	4347	3678
Low Loads														
Ave Water	Hydro	13081	12971	14587	16096	18280	17752	17677	18040	20230	19073	16819	12917	16460
	Coal	4294	4357	4167	4147	3751	3458	2931	1993	1271	1850	2666	4267	3263
	CT	214	247	148	155	169	129	158	174	0	11	128	404	161
High Water	Coal	4486	3636	3623	3892	3495	3295	2168	1326	861	972	973	3614	2695
	CT	249	34	6	31	0	0	0	0	0	0	0	41	30
Low Water	Coal	4542	4588	4591	4654	4773	4774	4519	3626	2649	4010	4780	4778	4357
	CT	267	371	324	337	1124	883	922	877	0	53	818	1045	585
Sales to PSW														
High Loads														
Economy Energy		1240	1753	1980	2721	2966	3597	3760	4120	4450	4106	3461	2014	3011
Net Export Sales		1893	1753	1328	2069	2314	2945	3760	4120	4450	4759	4114	2667	3011
Low Loads														
Economy Energy		3341	3604	4431	4845	5888	5969	5379	5105	6303	4984	4543	3281	4807
Net Export Sales		3994	3604	3779	4193	5236	5317	5379	5105	6303	5637	5196	3934	4807
BCH Economy Sales South														

High Loads														
	PNW	316	194	185	80	219	185	94	402	286	371	386	377	257
	PSW	284	276	252	122	95	181	54	158	71	120	191	497	192
Low Loads														
	PNW	186	71	95	57	143	212	147	183	36	78	68	295	131
	PSW	264	291	221	144	68	94	63	66	4	11	101	585	159

Table F-18

Table 5-A: Assured Delivery 100% PUB - Seasonal Exchange - Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	3.2	-0.2	-1.1	-0.5	-2.0	-1.2	0.5	0.4	0.3	0.3	0.5	1.1	0.0
	Coal	0.0	0.0	0.0	-0.3	-0.3	-0.7	-0.2	-0.8	-0.7	0.8	0.9	0.1	-0.1
	CT	1.6	-0.2	-5.6	-11.7	-2.7	-6.4	-2.7	-2.4	-2.4	4.9	8.4	6.2	-1.6
High Water	Coal	0.0	0.0	-0.1	-0.1	-0.1	-0.4	-0.6	0.1	-1.6	-1.1	3.6	0.1	0.0
	CT	0.3	0.7	-12.0	-7.6	-6.4	-8.7	5.9	7.1	0.0	0.0	25.7	13.0	-1.7
Low Water	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CT	0.4	0.2	-2.2	-10.3	0.0	-0.1	-1.0	-1.2	0.7	11.1	1.8	0.1	-0.5
Low Loads														
Ave Water	Hydro	6.3	-0.6	-3.5	-3.1	-0.5	-1.5	0.9	0.9	0.1	-0.1	0.3	0.6	-0.1
	Coal	-1.3	0.1	-0.7	-0.9	-5.8	-4.4	-2.2	-3.4	-0.9	-0.8	-0.9	0.4	-1.7
	CT	-20.1	3.8	-5.7	-8.8	-21.8	-16.8	-4.8	-6.5	0.0	83.3	7.6	14.8	-4.7
High Water	Coal	-1.4	1.1	-5.7	0.4	-8.6	-1.2	-6.7	-3.6	0.0	0.0	0.0	0.1	-2.4
	CT	-8.5	3.0	-33.3	14.8	-100.0	-100.0	0.0	0.0	0.0	0.0	0.0	7.9	-6.3
Low Water	Coal	-1.2	0.2	0.4	-0.7	0.0	0.0	0.0	0.0	-1.8	0.7	0.2	0.1	-0.1
	CT	-21.5	3.9	-1.2	-9.4	-8.0	-12.0	-4.3	-10.6	0.0	82.8	0.2	3.4	-5.5
Sales to PSW														
High Loads														
Economy Energy		-10.9	1.6	13.7	8.7	4.4	3.2	2.2	0.7	0.7	-11.2	-10.3	-12.5	-1.4
Net Export Sales		36.1	1.6	-23.8	-17.4	-18.5	-15.5	2.2	0.7	0.7	3.0	6.6	15.8	-1.4
Low Loads														
Economy Energy		-0.4	-1.4	0.9	2.5	4.8	2.5	1.0	1.3	0.1	-11.4	-11.6	-13.4	-1.9

Net Export Sales		19.0	-1.4	-13.9	-11.3	-6.9	-8.7	1.0	1.3	0.1	0.2	1.1	3.9	-1.9
BCH Economy Sales South														
High Loads														
	PNW	35.0	3.2	-26.3	56.9	-10.2	-22.3	3.3	-1.2	0.4	-3.1	-2.5	9.6	-1.2
	PSW	-2.1	23.8	16.1	-6.2	-7.8	4.6	-6.9	-3.7	1.4	-5.5	-7.3	-2.5	1.6
Low Loads														
	PNW	32.9	-4.1	-12.8	-3.4	-5.3	-13.1	-7.5	7.6	-5.3	25.8	1.5	7.3	1.6
	PSW	-20.7	7.0	-4.3	2.9	-12.8	-24.2	-17.1	-14.3	0.0	-15.4	-8.2	-4.4	-7.6

Table F-19

Table 5-B: Assured Delivery - 100% PUB - Seasonal Exchange - Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	345	-19	-151	-81	-370	-225	103	82	61	63	81	147	3
	Coal	0	0	-1	-16	-18	-37	-12	-29	-22	33	46	4	-4
	CT	61	-9	-202	-330	-66	-148	-43	-33	-1	34	121	197	-35
High Water	Coal	0	0	-5	-8	-7	-22	-28	2	-35	-20	142	3	2
	CT	11	19	-312	-150	-115	-147	45	29	0	0	26	275	-26
Low Water	Coal	0	0	0	-2	0	0	0	0	-1	-1	0	0	0
	CT	16	10	-95	-400	-2	-5	-40	-47	1	281	70	6	-17
Low Loads														
Ave Water	Hydro	781	-83	-530	-508	-97	-276	159	155	23	-18	58	82	-22
	Coal	-58	5	-28	-36	-232	-158	-65	-71	-12	-15	-25	19	-56
	CT	-54	9	-9	-15	-47	-26	-8	-12	0	5	9	52	-8
High Water	Coal	-65	41	-217	17	-329	-41	-156	-50	0	0	0	4	-66
	CT	-23	1	-3	4	-8	-1	0	0	0	0	0	3	-2
Low Water	Coal	-53	10	17	-33	-1	2	-1	-1	-49	27	11	6	-5
	CT	-73	14	-4	-35	-98	-120	-41	-104	0	24	2	34	-34
Sales to PSW														
High Loads														
Economy Energy		-151	28	239	218	126	112	80	29	33	-516	-399	-288	-43
Net Export Sales		502	28	-414	-435	-527	-541	80	29	33	137	254	365	-43
Low Loads														

Economy Energy	-14	-52	40	117	267	145	52	67	7	-641	-595	-506	-93
Net Export Sales	639	-52	-613	-536	-386	-508	52	67	7	12	58	147	-93
BCH Economy Sales South													
High Loads													
PNW	82	6	-66	29	-25	-53	3	-5	1	-12	-10	33	-3
PSW	-6	53	35	-8	-8	8	-4	-6	1	-7	-15	-13	3
Low Loads													
PNW	46	-3	-14	-2	-8	-32	-12	13	-2	16	1	20	2
PSW	-69	19	-10	4	-10	-30	-13	-11	0	-2	-9	-27	-13

Table F-20

Table 6: Assured Delivery - 52%/48% PUB/IOU - Seasonal Exchange - Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	11089	11941	13156	16593	18570	18520	19751	20184	22709	21399	17605	13232	17062
	Coal	5596	5653	5607	5703	5667	5568	4950	3751	3082	4048	4987	5708	5027
	CT	3783	3662	3443	2604	2368	2211	1535	1325	41	714	1515	3331	2211
High Water	Coal	5601	5645	5607	5712	5707	5685	4588	3450	2204	1771	4097	5733	4650
	CT	4085	2744	2425	1803	1647	1535	778	434	0	0	114	2327	1491
Low Water	Coal	5601	5666	5615	5749	5750	5750	5496	4572	4075	5328	5749	5750	5425
	CT	4164	4089	4209	3673	4401	4432	4145	3881	152	2751	4008	4322	3686
Low Loads														
Ave Water	Hydro	13070	12969	14580	16101	18282	17764	17676	18044	20227	19068	16809	12915	16459
	Coal	4297	4356	4166	4141	3746	3435	2931	1991	1273	1857	2669	4260	3260
	CT	232	245	145	151	173	131	159	172	0	11	136	422	165
High Water	Coal	4489	3635	3619	3884	3482	3249	2169	1324	861	1017	972	3609	2693
	CT	265	31	2	17	1	0	0	0	0	0	0	52	30
Low Water	Coal	4546	4579	4595	4652	4772	4773	4519	3626	2656	4012	4774	4777	4357
	CT	300	360	324	333	1145	898	919	874	0	49	863	1074	595
Sales to PSW														
High Loads														
Economy Energy		1163	1775	2055	2827	2994	3672	3746	4118	4446	4086	3418	1922	3017

	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
Net Export Sales	1816	1775	1403	2175	2342	3020	3746	4118	4446	4739	4071	2575	3017
Low Loads													
Economy Energy	3342	3595	4428	4843	5892	5970	5379	5107	6305	4986	4537	3290	4807
Net Export Sales	3995	3595	3776	4191	5240	5318	5379	5107	6305	5639	5190	3943	4807
BCH Economy Sales South													
High Loads													
PNW	310	189	183	69	213	176	99	401	289	392	419	396	262
PSW	288	272	250	125	100	187	54	163	70	98	162	467	186
Low Loads													
PNW	209	70	94	55	133	210	145	182	36	80	78	338	136
PSW	231	285	231	148	78	108	64	68	4	9	87	533	154

Table F-21

Table 6-A: Assured Delivery - 52%/48% PUB/IOU - Seasonal Exchange - Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	2.7	0.0	-0.8	-0.4	-1.8	-1.0	0.4	0.4	0.2	0.2	0.4	0.9	0.0
	Coal	0.0	0.0	0.0	-0.3	-0.3	-0.7	-0.2	-0.7	-0.6	0.9	1.0	0.0	-0.1
	CT	0.8	0.0	-4.3	-7.6	-2.2	-4.7	-2.7	-2.2	-2.4	3.5	4.7	4.5	-1.3
High Water	Coal	0.0	0.0	0.0	-0.2	-0.1	-0.4	-0.8	0.2	-1.6	-1.3	2.5	0.0	0.0
	CT	0.2	1.3	-6.9	-8.7	-7.7	-9.2	2.4	6.4	0.0	0.0	12.9	10.2	-1.8
Low Water	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CT	0.7	0.2	-2.4	-5.7	0.2	0.0	-0.8	-0.9	-0.7	8.3	1.1	-0.4	-0.2
Low Loads														
Ave Water	Hydro	6.3	-0.7	-3.6	-3.0	-0.5	-1.5	0.9	0.9	0.1	-0.1	0.3	0.6	-0.1
	Coal	-1.3	0.1	-0.7	-1.0	-6.0	-5.0	-2.2	-3.5	-0.8	-0.4	-0.8	0.3	-1.8
	CT	-13.4	2.9	-7.6	-11.2	-19.9	-15.5	-4.2	-7.5	0.0	83.3	-14.3	19.9	-2.4
High Water	Coal	-1.4	1.1	-5.8	0.2	-8.9	-2.6	-6.7	-3.8	0.0	4.6	-0.1	0.0	-2.5
	CT	-2.6	-6.1	-77.8	-37.0	-87.5	-100.0	0.0	0.0	0.0	0.0	0.0	36.8	-6.3
Low Water	Coal	-1.1	0.0	0.5	-0.7	0.0	0.0	0.0	0.0	-1.6	0.7	0.1	0.1	-0.1
	CT	-11.8	0.8	-1.2	-10.5	-6.3	-10.5	-4.6	-10.9	0.0	69.0	5.8	6.2	-3.9
Sales to PSW														

High Loads													
Economy Energy	-16.4	2.9	18.0	12.9	5.4	5.4	1.8	0.7	0.7	-11.6	-11.5	-16.5	-1.2
Net Export Sales	30.5	2.9	-19.4	-13.1	-17.6	-13.4	1.8	0.7	0.7	2.5	5.5	11.8	-1.2
Low Loads													
Economy Energy	-0.4	-1.7	0.8	2.4	4.8	2.5	1.0	1.4	0.1	-11.4	-11.7	-13.1	-1.9
Net Export Sales	19.1	-1.7	-14.0	-11.4	-6.8	-8.7	1.0	1.4	0.1	0.2	1.0	4.1	-1.9
BCH Economy Sales South													
High Loads													
PNW	32.5	0.5	-27.1	35.3	-12.7	-26.1	8.8	-1.5	1.4	2.3	5.8	15.1	0.8
PSW	-0.7	22.0	15.2	-3.8	-2.9	8.1	-6.9	-0.6	0.0	-22.8	-21.4	-8.4	-1.6
Low Loads													
PNW	49.3	-5.4	-13.8	-6.8	-11.9	-13.9	-8.8	7.1	-5.3	29.0	16.4	22.9	5.4
PSW	-30.6	4.8	0.0	5.7	0.0	-12.9	-15.8	-11.7	0.0	-30.8	-20.9	-12.9	-10.5

Table F-22

Table 6-B: Assured Delivery - 52%/48% PUB/IOU - Seasonal Exchange - Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	296	4	-112	-75	-340	-180	72	71	55	53	74	119	3
	Coal	0	0	-1	-16	-18	-38	-10	-27	-20	36	48	1	-3
	CT	30	-1	-154	-214	-54	-109	-42	-30	-1	24	68	143	-28
High Water	Coal	0	1	0	-9	-7	-25	-35	8	-36	-23	98	0	-2
	CT	8	34	-181	-172	-137	-155	18	26	0	0	13	215	-27
Low Water	Coal	0	0	0	-1	0	0	0	0	-2	2	0	0	0
	CT	27	10	-104	-222	9	0	-34	-37	-1	212	45	-19	-9
Low Loads														
Ave Water	Hydro	770	-85	-537	-503	-95	-264	158	159	20	-23	48	80	-23
	Coal	-55	4	-29	-42	-237	-181	-65	-73	-10	-8	-22	12	-59
	CT	-36	7	-12	-19	-43	-24	-7	-14	0	5	17	70	-4
High Water	Coal	-62	40	-221	9	-342	-87	-155	-52	0	45	-1	-1	-68
	CT	-7	-2	-7	-10	-7	-1	0	0	0	0	0	14	-2
Low Water	Coal	-49	1	21	-35	-2	1	-1	-1	-42	29	5	5	-5

	CT	-40	3	-4	-39	-77	-105	-44	-107	0	20	47	63	-24
Sales to PSW														
High Loads														
Economy Energy		-228	50	314	324	154	187	66	27	29	-536	-442	-380	-37
Net Export Sales		425	50	-339	-329	-499	-466	66	27	29	117	211	273	-37
Low Loads														
Economy Energy		-13	-61	37	115	271	146	52	69	9	-639	-601	-497	-93
Net Export Sales		640	-61	-616	-538	-382	-507	52	69	9	14	52	156	93
BCH Economy Sales South														
High Loads														
	PNW	76	1	-68	18	-31	-62	8	-6	4	9	23	52	2
	PSW	-2	49	33	-5	-3	14	-4	-1	0	-29	-44	-43	-3
Low Loads														
	PNW	69	-4	-15	-4	-18	-34	-14	12	-2	18	11	63	7
	PSW	-102	13	0	8	0	-16	-12	-9	0	-4	-23	-79	-18

Table F-23

Table 7: Federal Marketing Case A Combined With Capacity Ownership - 100% PUB - Seasonal Exchange

Resource Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	11777	11850	12944	16573	18236	18356	19857	20129	22739	21455	17484	13292	17058
	Coal	5596	5647	5605	5682	5671	5531	4835	3671	3192	4056	5024	5710	5018
	CT	3636	3494	3225	2293	2301	2000	1407	1297	54	794	1621	3363	2124
High Water	Coal	5601	5655	5598	5666	5708	5607	4413	3360	2196	1749	4217	5740	4626
	CT	3895	2569	2125	1637	1607	1339	502	300	0	0	136	2432	1378
Low Water	Coal	5601	5666	5615	5744	5750	5750	5496	4573	4083	5326	5750	5750	5425
	CT	3991	3933	4039	3236	4383	4387	4066	3925	189	3041	4053	4324	3631
Low Loads														
Ave Water	Hydro	13632	12642	14373	16031	18308	17752	17579	18099	20188	19054	16822	12923	16450
	Coal	4183	4386	4154	4152	3756	3447	2901	1967	1263	1832	2676	4269	3249
	CT	173	295	146	156	169	128	153	194	0	15	131	404	163
High Water	Coal	4396	3713	3427	3868	3497	3285	2192	1308	861	973	973	3621	2676

	CT	186	54	2	39	1	0	0	0	0	0	0	50	27
Low Water	Coal	4446	4620	4599	4662	4772	4773	4519	3624	2649	4031	4780	4777	4354
	CT	207	424	332	353	1162	941	874	960	0	91	823	1030	600
Sales to PSW														
High Loads														
Economy Energy		1562	2101	2284	3078	3263	3885	4168	3969	3674	3270	3422	1990	3054
Net Export Sales		2287	1421	879	1673	1858	2480	3488	3969	4774	5095	4147	2715	2897
Low Loads														
Economy Energy		3691	3893	4834	5297	6456	6513	5918	5138	5357	4033	4545	3260	4910
Net Export Sales		4416	3213	3429	3892	5051	5108	5238	5138	6457	5858	5270	3985	4753
BCH Economy Sales South														
High Loads														
	PNW	180	245	290	94	239	227	130	473	268	343	387	355	269
	PSW	313	205	202	99	83	151	36	96	45	134	188	489	170
Low Loads														
	PNW	220	103	179	58	161	257	269	190	33	75	63	288	159
	PSW	220	202	189	80	47	57	52	38	4	10	95	560	129

Table F-24

Table 7-A: Federal Marketing Case A Combined With Capacity Ownership - 100% PUB - Seasonal Exchange

Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	9.1	-0.7	-2.4	-0.6	-3.6	-1.8	0.9	0.1	0.4	0.5	-0.3	1.4	0.0
	Coal	0.0	-0.1	-0.1	-0.6	-0.2	-1.3	-2.5	-2.8	2.9	1.1	1.7	0.1	-0.2
	CT	-3.1	-4.6	-10.3	-18.6	-5.0	-13.8	-10.8	-4.3	28.6	15.1	12.0	5.5	-5.1
High Water	Coal	0.0	0.2	-0.2	-1.0	-0.1	-1.8	-4.5	-2.4	-2.0	-2.5	5.5	0.1	-0.6
	CT	-4.5	-5.2	-18.5	-17.1	-9.9	-20.8	-33.9	-26.5	0.0	0.0	34.7	15.2	-9.2
Low Water	Coal	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
	CT	-3.5	-3.6	-6.4	-16.9	-0.2	-1.0	-2.7	0.2	23.5	19.8	2.3	-0.4	-1.7
Low Loads														
Ave Water	Hydro	10.8	-3.2	-4.9	-3.5	-0.4	-1.5	0.3	1.2	-0.1	-0.2	0.4	0.7	-0.2
	Coal	-3.9	0.8	-1.0	-0.7	-5.7	-4.7	-3.2	-4.7	-1.6	-1.8	-0.6	0.5	-2.1

	CT	-35.4	23.9	-7.0	-8.2	-21.8	-17.4	-7.8	4.3	0.0	150.0	10.1	14.8	-3.6
High Water	Coal	-3.4	3.3	-10.8	-0.2	-8.6	-1.5	-5.7	-4.9	0.0	0.1	0.0	0.3	-3.1
	CT	-31.6	63.6	-77.8	44.4	-87.5	-100.0	0.0	0.0	0.0	0.0	0.0	31.6	-15.6
Low Water	Coal	3.2	0.9	0.5	-0.5	0.0	0.0	0.0	-0.1	-1.8	1.2	0.2	0.1	-0.2
	CT	-39.1	18.8	1.2	-5.1	-4.9	-6.2	-9.2	-2.1	0.0	213.8	0.9	1.9	-3.1
Sales to PSW														
High Loads														
Economy Energy		12.3	21.8	31.2	23.0	14.9	11.5	13.3	-3.0	-16.8	-29.3	-11.3	-13.6	0.0
Net Export Sales		64.4	-17.6	-49.5	-33.2	-34.6	-28.8	-5.2	-3.0	8.1	10.2	7.4	17.9	-5.1
Low Loads														
Economy Energy		10.0	6.5	10.1	12.0	14.9	11.8	11.1	2.0	-14.9	-28.3	-11.5	-13.9	0.2
Net Export Sales		31.6	-12.1	-21.9	-17.7	-10.1	-12.3	-1.7	2.0	2.6	4.1	2.6	5.2	-3.0
BCH Economy Sales South														
High Loads														
	PNW	-23.1	30.3	15.5	84.3	-2.0	-4.6	42.9	16.2	-6.0	-10.4	-2.3	3.2	3.5
	PSW	7.9	-8.1	-6.9	-23.8	-19.4	-12.7	-37.9	-41.5	-35.7	5.5	-8.7	-4.1	-10.1
Low Loads														
	PNW	57.1	39.2	64.2	-1.7	6.6	5.3	69.2	11.8	-13.2	21.0	-6.0	4.7	23.3
	PSW	-33.9	-25.7	-18.2	-42.9	-39.7	-54.0	-31.6	-50.6	0.0	-23.1	-13.6	-8.5	-25.0

Table F-25

Table 7-B: Federal Marketing Case A Combined With Capacity Ownership - 100% PUB - Seasonal Exchange

Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	984	-87	-324	-95	-674	-344	78	16	85	109	-47	179	-1
	Coal	0	-6	-3	-37	-14	-75	-125	-107	90	44	85	3	-12
	CT	-117	-169	-372	-525	-121	-320	-170	-58	12	104	174	175	-115
High Water	Coal	0	11	-9	-55	-6	-103	-210	-82	-44	-45	218	7	-26
	CT	-182	-141	-481	-338	-177	-351	-258	-108	0	0	35	320	-140
Low Water	Coal	0	0	0	-6	0	0	0	1	6	0	1	0	0
	CT	-146	-146	-274	-659	-9	-45	-113	7	36	502	90	-17	-64
Low Loads														

Ave Water	Hydro	1332	-412	-744	-573	-69	-276	61	214	-19	-37	61	88	-32
	Coal	-169	34	-41	-31	-227	-169	-95	-97	-20	-33	-15	21	-70
	CT	-95	57	-11	-14	-47	-27	-13	8	0	9	12	52	-6
High Water	Coal	-155	118	-413	-7	-327	-51	-132	-68	0	1	0	11	-85
	CT	-86	21	-7	12	-7	-1	0	0	0	0	0	12	-5
Low Water	Coal	-149	42	25	-25	-2	1	1	-3	-49	48	11	5	-8
	CT	-133	67	4	-19	-60	-62	-89	-21	0	62	7	19	-19
Sales to PSW														
High Loads														
Economy Energy		171	376	543	575	423	400	488	-122	-743	-1352	-438	-312	0
Net Export Sales		896	-304	-862	-830	-982	-1005	-192	-122	357	473	287	413	-157
Low Loads														
Economy Energy		336	237	443	569	835	689	591	100	-939	-1592	-593	-527	10
Net Export Sales		1061	-443	62	-836	-570	-716	-89	100	161	233	132	198	-147
BCH Economy Sales South														
High Loads	PNW	-54	57	39	43	-5	-11	39	66	-17	-40	-9	11	9
	PSW	23	-18	-15	-31	-20	-22	-22	-68	-25	7	-18	-21	-19
Low Loads														
	PNW	80	29	70	-1	10	13	110	20	-5	13	-4	13	30
	PSW	-113	-70	-42	-60	-31	-67	-24	-39	0	-3	-15	-52	-43

Table F-26

Table B: Federal Marketing Case A Combined With Capacity Ownership - 52%/48% PUB/IOU - Seasonal Exchange

Resource Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	11682	11863	13039	16555	18293	18428	19825	20109	22724	21465	17461	13267	17059
	Coal	5595	5650	5606	5682	5669	5532	4845	3677	3176	4068	5023	5708	5019
	CT	3592	3536	3311	2393	2308	2041	1418	1306	53	786	1580	3302	2136
High Water	Coal	5601	5654	5600	5654	5703	5618	4441	3376	2196	1752	4209	5737	4628
	CT	3879	2581	2256	1625	1594	1353	509	298	0	0	109	2327	1378
Low Water	Coal	5601	5666	5615	5747	5750	5750	5496	4573	4082	5329	5749	5750	5426

	CT	3977	3975	4081	3473	4396	4405	4115	3939	193	3013	4054	4318	3662
Low Loads														
Ave Water	Hydro	13627	12642	14377	16021	18313	17750	17583	18101	20185	19049	16811	12918	16448
	Coal	4187	4373	4144	4142	3754	3448	2911	1964	1264	1832	2678	4262	3247
	CT	190	266	136	145	163	120	149	182	0	17	140	424	161
High Water	Coal	4412	3711	3453	3884	3498	3285	2188	1311	861	972	973	3609	2680
	CT	211	59	2	38	0	0	0	0	0	0	0	59	31
Low Water	Coal	4450	4591	4570	4630	4772	4771	4520	3625	2654	4024	4777	4776	4347
	CT	232	395	306	313	1139	877	867	912	0	100	868	1063	589
Sales to PSW														
High Loads														
Economy Energy		1425	2152	2461	3164	3314	3983	4169	3986	3652	3258	3372	1893	3068
Net Export Sales		2150	1472	1056	1759	1909	2578	3489	3986	4752	5083	4097	2618	2911
Low Loads														
Economy Energy		3699	3860	4837	5291	6462	6516	5933	5128	5355	4032	4536	3268	4911
Net Export Sales		4424	3180	3432	3886	5057	5111	5253	5128	6455	5857	5261	3993	4754
BCH Economy Sales South														
High Loads														
	PNW	194	188	226	78	225	196	135	494	268	368	430	384	266
	PSW	294	258	270	126	100	184	37	94	46	76	156	452	174
Low Loads														
	PNW	250	81	161	55	153	247	270	187	32	77	73	330	160
	PSW	179	230	224	107	58	77	56	44	4	8	79	513	131

Table F-27

Table 8-A: Federal Marketing Case A Combined With Capacity Ownership - 52%/48% PUB/IOU - Seasonal Exchange

Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	8.2	-0.6	-1.7	-0.7	-3.3	-1.5	0.7	0.0	0.3	0.6	-0.4	1.2	0.0
	Coal	0.0	-0.1	0.0	-0.6	-0.3	-1.3	-2.3	-2.7	2.4	1.4	1.7	0.0	-0.2
	CT	-4.3	-3.5	-8.0	-15.1	-4.7	-12.0	-10.1	-3.6	26.2	13.9	9.2	3.6	-4.6
High Water	Coal	0.0	0.2	-0.1	-1.2	-0.2	-1.6	-3.9	-1.9	-2.0	-2.3	5.3	0.1	-0.5

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            CT       -4.9   -4.8  -13.4  -17.7  -10.7  -19.9  -33.0  -27.0
0.0    0.0    7.9   10.2   -9.2
Low Water   Coal      0.0    0.0    0.0   -0.1    0.0    0.0    0.0    0.0
0.1    0.1    0.0    0.0    0.0
            CT       -3.9   -2.5   -5.4  -10.8    0.1   -0.6   -1.5    0.5
26.1   18.7    2.3   -0.5   -0.9
Low Loads
Ave Water   Hydro    10.8   -3.2   -4.9   -3.5   -0.3   -1.5    0.4    1.2   -
0.1   -0.2    0.3    0.6   -0.2
            Coal     -3.8    0.5   -1.2   -1.0   -5.7   -4.6   -2.8   -4.8   -
1.5   -1.8   -0.5    0.3   -2.2
            CT      -29.1   11.8  -13.4  -14.7  -24.5  -22.6  -10.2   -2.2
0.0  183.3   17.6   20.5   -4.7
High Water  Coal     -3.1    3.2  -10.1    0.2   -8.5   -1.5   -5.9   -4.7
0.0    0.0    0.0    0.0   -2.9
            CT      -22.4   78.8  -77.8   40.7 -100.0 -100.0    0.0    0.0
0.0    0.0    0.0   55.3   -3.1
Low Water   Coal     -3.2    0.3   -0.1   -1.2    0.0    0.0    0.0   -0.1   -
1.6    1.0    0.2    0.1   -0.3
            CT      -31.8   10.6   -6.7  -15.9   -6.8  -12.6  -10.0   -7.0
0.0  244.8    6.4    5.1   -4.8
Sales to PSW
High Loads
Economy Energy        2.4   24.8   41.4   26.4   16.7   14.3   13.3   -2.6  -
17.3  -29.5  -12.6  -17.8    0.5
Net Export Sales     54.6  -14.7  -39.3  -29.7  -32.8  -26.0   -5.2   -2.6
7.6   10.0    6.1   13.7   -4.7
Low Loads
Economy Energy       10.3    5.6   10.2   11.9   15.0   11.9   11.4    1.8  -
14.9  -28.3  -11.7  -13.7    0.2
Net Export Sales     31.9  -13.0  -21.8  -17.8  -10.0  -12.2   -1.4    1.8
2.5    4.1    2.4    5.4   -3.0
BCH Economy Sales South
High Loads
            PNW     -17.1    0.0  -10.0   52.9   -7.8  -17.6   48.4   21.4   -
6.0   -3.9    8.6   11.6    2.3
            PSW       1.4   15.7   24.4   -3.1   -2.9    6.4  -36.2  -42.7  -
34.3  -40.2  -24.3  -11.4   -7.9
Low Loads
            PNW      78.6    9.5   47.7   -6.8    1.3    1.2   69.8   10.0  -
15.8   24.2    9.0   20.0   24.0
            PSW     -46.2  -15.4   -3.0  -23.6  -25.6  -37.9  -26.3  -42.9
0.0  -38.5  -28.2  -16.2  -23.8
```

Table F-28

Table 8-B: Federal Marketing Case A Combined With Capacity Ownership - 52%/48% PUB/IOU - Seasonal Exchange

Average MW Change From No Action Case

```
PNW Generation        SEP    OCT    NOV    DEC    JAN    FEB    MAR    APR
MAY    JUN    JUL    AUG    AVE
High Loads
Ave Water   Hydro     889    -74   -229   -113   -617   -272    146     -4
70    119    -70    154      0
            Coal       -1     -3     -2    -37    -16    -74   -115   -101
74     56     84      1    -11
```

	CT	-161	-127	-286	-425	-114	-279	-159	-49	11	96	133	114	-103
High Water	Coal	0	10	-7	-67	-11	-92	-182	-66	-44	-42	210	4	-24
	CT	-198	-129	-350	-350	-190	-337	-251	-110	0	0	8	215	-140
Low Water	Coal	0	0	0	-3	0	0	0	1	5	3	0	0	1
	CT	-160	-104	-232	-422	4	-27	-64	21	40	474	91	-23	-33
Low Loads														
Ave Water	Hydro	1327	-412	-740	-583	-64	-278	65	216	-22	-42	50	83	-34
	Coal	-165	21	-51	-41	-229	-168	-85	-100	-19	-33	-13	14	-72
	CT	-78	28	-21	-25	-53	-35	-17	-4	0	11	21	72	-8
High Water	Coal	-139	116	-387	9	-326	-51	-136	-65	0	0	0	-1	-81
	CT	-61	26	-7	11	-8	-1	0	0	0	0	0	21	-1
Low Water	Coal	-145	13	-4	-57	-2	-1	0	-2	-44	41	8	4	-15
	CT	-108	38	-22	-59	-83	-126	-96	-69	0	71	52	52	-30
Sales to PSW														
High Loads														
Economy Energy		34	427	720	661	474	498	489	-105	-765	-1364	-488	-409	14
Net Export Sales		759	-253	-685	-744	-931	-907	-191	-105	335	461	237	316	-143
Low Loads														
Economy Energy		344	204	446	563	841	692	606	90	-941	-1593	-602	-519	11
Net Export Sales		1069	-476	-959	-842	-564	-713	-74	90	159	232	123	206	-146
BCH Economy Sales South														
High Loads														
	PNW	-40	0	-25	27	-19	-42	44	87	-17	-15	34	40	6
	PSW	4	35	53	-4	-3	11	-21	-70	-24	-51	-50	-58	-15
Low Loads														
	PNW	110	7	52	-4	2	3	111	17	-6	15	6	55	31
	PSW	-154	-42	-7	-33	-20	-47	-20	-33	0	-5	-31	-99	-41

Table F-29

Table 9: Federal Marketing Case A Combined With Assured Delivery - 100% PUB - Seasonal Exchange

Resource Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														

Ave Water	Hydro	11772	11818	12935	16559	18253	18371	19828	20137	22749	21483	17488	13295	17057
	Coal	5596	5649	5605	5678	5667	5522	4843	3659	3157	4034	5022	5711	5012
	CT	3638	3472	3230	2254	2283	1975	1399	1285	51	777	1619	3347	2111
High Water	Coal	5601	5654	5598	5669	5708	5591	4454	3339	2192	1750	4253	5739	4629
	CT	3906	2524	2118	1613	1628	1317	509	282	0	0	136	2416	1371
Low Water	Coal	5601	5666	5615	5743	5750	5750	5496	4573	4082	5326	5750	5750	5425
	CT	4003	3897	4062	3205	4373	4388	4084	3895	193	3027	4049	4325	3625
Low Loads														
Ave Water	Hydro	13636	12661	14380	16016	18301	17762	17567	18093	20183	19044	16820	12923	16449
	Coal	4180	4349	4137	4135	3754	3445	2917	1974	1264	1834	2674	4268	3244
	CT	172	224	134	132	143	101	135	165	0	15	131	405	147
High Water	Coal	4394	3711	3458	3890	3495	3292	2200	1318	861	973	973	3621	2682
	CT	186	60	4	41	1	0	0	0	0	0	0	49	28
Low Water	Coal	4442	4580	4558	4588	4776	4776	4520	3628	2641	4041	4779	4777	4340
	CT	207	350	287	258	979	743	766	798	0	92	823	1032	528
Sales to PSW														
High Loads														
Economy Energy		1583	2080	2282	3045	3250	3862	4154	3944	3661	3271	3444	2010	3046
Net Export Sales		2308	1370	877	1640	1845	2457	3474	3944	4761	5096	4169	2735	2889
Low Loads														
Economy Energy		3699	3863	4830	5298	6437	6518	5923	5125	5355	4028	4549	3277	4912
Net Export Sales		4424	3183	3425	3893	8032	5113	5243	5125	6455	5853	5274	4002	4755
BCH Economy Sales South														
High Loads														
	PNW	185	154	203	84	215	195	121	438	266	358	403	370	250
	PSW	331	300	293	138	116	193	52	127	60	134	198	510	204
Low Loads														
	PNW	224	52	120	53	140	227	249	177	33	77	66	293	142
	PSW	223	311	267	142	72	102	90	65	4	10	95	574	163

Table F-30

Table 9-A: Federal Marketing Case A Combined With Assured Delivery - 100% PUB - Seasonal Exchange

Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	9.1	-1.0	-2.5	-0.7	-3.5	-1.8	0.8	0.1	0.4	0.6	-0.2	1.4	0.0
	Coal	0.0	-0.1	-0.1	-0.7	-0.3	-1.5	-2.4	-3.1	1.8	0.5	1.7	0.1	-0.4
	CT	-3.1	-5.2	-10.2	-20.0	-5.7	-14.9	-11.3	-5.2	21.4	12.6	11.9	5.0	-5.7
High Water	Coal	0.0	0.2	-0.2	-0.9	-0.1	-2.1	-3.7	-3.0	-2.1	-2.5	6.4	0.1	-0.5
	CT	-4.2	-6.9	-18.7	-18.3	-8.7	-22.1	-33.0	-30.9	0.0	0.0	34.7	14.4	-9.7
Low Water	Coal	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
	CT	-3.2	-4.5	-5.8	-17.7	-0.4	-1.0	-2.3	-0.6	26.1	19.2	2.2	-0.4	-1.9
Low Loads														
Ave Water	Hydro	10.9	-3.0	-4.9	-3.5	-0.4	-1.5	0.3	1.2	-0.1	-0.2	0.4	0.7	-0.2
	Coal	-4.0	-0.1	-1.4	-1.1	-5.7	-4.7	-2.6	-4.4	-1.5	-1.7	-0.6	0.5	-2.3
	CT	-35.8	-5.9	-14.6	-22.4	-33.8	-34.8	-18.7	-11.3	0.0	150.0	10.1	15.1	-13.0
High Water	Coal	-3.4	3.2	-9.9	0.4	-8.6	-1.3	-5.3	-4.2	0.0	0.1	0.0	0.3	-2.9
	CT	-31.6	81.8	-55.6	51.9	-87.5	-100.0	0.0	0.0	0.0	0.0	0.0	28.9	-12.5
Low Water	Coal	-3.3	-0.6	-0.3	-2.1	0.0	0.1	0.0	0.0	-2.1	1.5	0.2	0.1	-0.5
	CT	-39.1	-2.0	-12.5	-30.6	-19.9	-25.9	-20.5	-18.7	0.0	217.2	0.9	2.1	-14.7
Sales to PSW														
High Loads														
Economy Energy		13.8	18.8	31.1	21.7	14.4	10.8	12.9	-3.6	-17.1	-29.2	-10.8	-12.7	-0.3
Net Export Sales		65.9	-20.6	-49.6	-34.5	-35.0	-29.5	-5.6	-3.6	7.8	10.3	8.0	18.8	-5.4
Low Loads														
Economy Energy		10.3	5.7	10.0	12.1	14.5	11.9	11.2	1.7	-14.9	-28.4	-11.5	-13.5	0.2
Net Export Sales		31.9	-12.9	-22.0	-17.7	-10.5	-12.2	-1.6	1.7	2.5	4.1	2.6	5.7	-3.0
BCH Economy Sales South														
High Loads														
	PNW	-20.9	-18.1	-19.1	64.7	-11.9	-18.1	33.0	7.6	-6.7	-6.5	1.8	7.6	-3.8
	PSW	14.1	34.5	35.0	6.2	12.6	11.6	-10.3	-22.6	-14.3	5.5	-3.9	0.0	7.9
Low Loads														
	PNW	60.0	-29.7	10.1	-10.2	-7.3	-7.0	56.6	4.1	-13.2	24.2	-1.5	6.5	10.1
	PSW	-33.0	14.3	15.6	1.4	-7.7	-17.7	18.4	-15.6	0.0	-23.1	-13.6	-6.2	-5.2

Table F-31

Table 9-B: Federal Marketing Case A Combined With Assured Delivery - 100% PUB - Seasonal Exchange

Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	979	-119	-333	-109	-657	-329	149	24	95	137	-43	182	-2
	Coal	0	-4	-3	-41	-18	-84	-117	-119	55	22	83	4	-18
	CT	-115	-191	-367	-564	-139	-345	-178	-70	9	87	172	159	-128
High Water	Coal	0	10	-9	-52	-6	-119	-169	-103	-48	-44	254	6	-23
	CT	-171	-186	-488	-362	-156	-373	-251	-126	0	0	35	304	-147
Low Water	Coal	0	0	0	-7	0	0	0	1	5	0	1	0	0
	CT	-134	-182	-251	-690	-19	-44	-95	-23	40	488	86	-16	-70
Low Loads														
Ave Water	Hydro	1336	-393	-737	-588	-76	-266	49	208	-24	-47	59	88	-33
	Coal	-172	-3	-58	-48	-229	-171	-79	-90	-19	-31	-17	20	-75
	CT	-96	-14	-23	-38	-73	-54	-31	-21	0	9	12	53	-22
High Water	Coal	-157	116	-382	15	-329	-44	-124	-58	0	1	0	11	-79
	CT	-86	27	-5	14	-7	-1	0	0	0	0	0	11	-4
Low Water	Coal	-153	-28	-16	-99	2	4	0	1	-57	58	10	5	-22
	CT	-133	-7	-41	-114	-243	-260	-197	-183	0	63	7	21	-91
Sales to PSW														
High Loads														
Economy Energy		192	325	541	542	410	377	474	-147	-756	-1351	-416	-292	-8
Net Export Sales		917	-355	-864	-863	-995	-1028	-206	-147	344	474	309	433	-165
Low Loads														
Economy Energy		344	207	439	570	816	694	596	87	-941	-1597	-589	-510	12
Net Export Sales		1069	-473	-966	-835	-589	-711	-84	87	159	228	136	215	-145
BCH Economy Sales South														
High Loads														
	PNW	-49	-34	-48	33	-29	-43	30	31	-19	-25	7	26	-10
	PSW	41	77	76	8	13	20	-6	-37	-10	7	-8	0	15
Low Loads														
	PNW	84	-22	11	-6	-11	-17	90	7	-5	15	-1	18	13

	PSW	-110	39	36	2	-6	-22	14	-12	0	-3	-15	-38	-9

Table F-32

Table 10: Federal Marketing Case A Combined With Assured Delivery - 52%/48% PUB/IOU - Seasonal Exchange

Resource Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	11675	11837	13039	16530	18306	18428	19783	20127	22738	21497	17463	13270	17058
	Coal	5595	5649	5606	5676	5663	5511	4846	3652	3161	4042	5019	5707	5011
	CT	3602	3481	3282	2333	2296	2013	1406	1290	51	758	1577	3287	2115
High Water	Coal	5601	5654	5601	5652	5699	5601	4419	3332	2190	1745	4204	5735	4619
	CT	3889	2562	2231	1565	1597	1305	5OO	271	0	0	103	2301	1360
Low Water	Coal	5601	5666	5615	5746	5750	5750	5496	4572	4082	5329	5749	5750	5425
	CT	3986	3906	4049	3392	4395	4399	4130	3921	195	2995	4070	4313	3646
Low Loads														
Ave Water	Hydro	13632	12657	14380	16017	18308	17777	17570	18088	20183	19047	16812	12917	16449
	Coal	4184	4350	4128	4129	3745	3417	2918	1977	1264	1833	2676	4262	3240
	CT	189	223	130	131	149	105	135	165	0	16	140	426	151
High Water	Coal	4412	3717	3452	3884	3482	3227	2204	1329	861	972	973	3607	2677
	CT	209	59	4	30	0	0	0	0	0	0	0	59	30
Low Water	Coal	4446	4554	4559	4590	4774	4773	4520	3627	2647	4039	4781	4777	4341
	CT	229	345	284	264	1011	770	772	798	0	95	871	1064	542
Sales to PSW														
High Loads														
Economy Energy		1448	2064	2419	3086	3293	3929	4135	3943	3657	3255	3395	1912	3042
Net Export Sales		2173		1014	1681	1888	2524	3455	3943	4757	5080	4120	2637	2885
Low Loads														
Economy Energy		3706	3854	4829	5295	6441	6516	5925	5122	5352	4033	4542	3284	4910
Net Export Sales		4431	3174	3424	3890	5036	5111	5245	5122	6452	5858	5267	4009	4753
BCH Economy Sales South														
High Loads														
	PNW	199	147	172	76	208	169	123	442	268	387	448	396	254
	PSW	308	293	312	142	121	216	55	128	60	75	163	469	195

		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
Low Loads														
	PNW	255	51	118	52	130	218	248	175	32	78	76	337	148
	PSW	181	302	278	143	82	119	88	67	4	8	81	523	156

Table F-33

Table 10-A: Federal Marketing Case A Combined With Assured Delivery - 52%/48% PUB/IOU - Seasonal Exchange

Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	8.2	-0.8	-1.7	-0.8	-3.2	-1.5	0.5	0.1	0.4	0.7	-0.4	1.2	0.0
	Coal	0.0	-0.1	0.0	-0.8	-0.4	-1.7	-2.3	-3.3	1.9	0.7	1.6	0.0	-0.4
	CT	-4.0	-5.0	-8.8	-17.2	-5.2	-13.2	-10.8	-4.8	21.4	9.9	9.0	3.1	-5.5
High Water	Coal	0.0	0.2	-0.1	-1.2	-0.3	-1.9	-4.4	-3.2	-2.2	-2.7	5.1	0.0	-0.7
	CT	-4.6	-5.5	-14.4	-20.8	-10.5	-22.8	-34.2	-33.6	0.0	0.0	2.0	8.9	-10.4
Low Water	Coal	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0
	CT	-3.6	-4.2	-6.1	-12.9	0.1	-0.7	-1.2	0.1	27.5	18.0	2.7	-0.6	-1.3
Low Loads														
Ave Water	Hydro	10.8	-3.0	-4.9	-3.5	-0.4	-1.4	0.3	1.1	-0.1	-0.2	0.3	0.6	-0.2
	Coal	-3.9	0.0	-1.6	-1.3	-6.0	-5.5	-2.6	-4.2	-1.5	-1.7	-0.6	0.3	-2.4
	CT	-29.5	-6.3	-17.2	-22.9	-31.0	-32.3	-18.7	-11.3	0.0	166.7	17.6	21.0	-10.7
High Water	Coal	-3.1	3.4	-10.1	0.2	-8.9	-3.3	-5.2	-3.4	0.0	0.0	0.0	-0.1	-3.0
	CT	-23.2	78.8	-55.6	11.1	-100.0	-100.0	0.0	0.0	0.0	0.0	0.0	55.3	-6.3
Low Water	Coal	-3.2	-0.5	--0.3	-2.1	0.0	0.0	0.0	0.0	-1.9	1.4	0.3	0.1	-0.5
	CT	-32.6	-3.4	-13.4	-29.0	-17.3	-23.2	-19.8	-18.7	0.0	227.6	6.7	5.2	-12.4
Sales to PSW														
High Loads														
Economy Energy		4.1	19.7	38.9	23.3	16.0	12.7	12.4	-3.6	-17.2	-29.6	-12.0	-16.9	-0.4
Net Export Sales		56.2	-19.8	-41.8	-32.8	-33.5	-27.6	-6.1	-3.6	7.7	9.9	6.7	14.6	-5.5
Low Loads														
Economy Energy		10.5	5.4	10.0	12.0	14.6	11.9	11.2	1.7	-15.0	-28.3	-11.6	-13.3	0.2
Net Export Sales		32.1	-13.2	-22.0	-17.7	-10.4	-12.2	-1.5	1.7	2.5	4.1	2.5	5.9	-3.0
BCH Economy Sales South														
High Loads														

	PNW	-15.0	-21.8	-31.5	49.0	-14.8	-29.0	35.2	8.6	-6.0	1.0	13.1	15.1	-2.3
	PSW	6.2	31.4	43.8	9.2	17.5	24.9	-5.2	-22.0	-14.3	-40.9	-20.9	-8.0	3.2
Low Loads														
	PNW	82.1	-31.1	8.3	-11.9	-13.9	-10.7	56.0	2.9	-15.8	25.8	13.4	22.5	14.7
	PSW	-45.6	11.0	20.3	2.1	5.1	-4.0	15.8	-13.0	0.0	-38.5	-26.4	-14.5	-9.3

Table F-34

Table 10-B: Federal Marketing Case A Combined With Assured Delivery - 52%/48% PUB/IOU - Seasonal Exchange

Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	882	-100	-229	-138	-604	-272	104	14	84	151	-68	157	-1
	Coal	-1	-4	-2	-43	-22	-95	-114	-126	59	30	80	0	-19
	CT	-151	-182	-315	-485	-126	-307	-171	-65	9	68	130	99	-124
High Water	Coal	0	10	-6	-69	-15	-109	-204	-110	-50	-49	205	2	-33
	CT	-188	-148	-375	-410	-187	-385	-260	-137	0	0	2	189	-158
	Coal	0	0	0	-4	0	0	0	0	5	3	0	0	0
	CT	-151	-173	-264	-503	3	-33	-49	3	42	456	107	-28	-49
Low Loads														
Ave Water	Hydro	1332	-397	-737	-587	-69	-251	52	203	-24	-44	51	82	-33
	Coal	-168	-2	-67	-54	-238	-199	-78	-87	-19	-32	-15	14	-79
	CT	-79	-15	-27	-39	-67	-50	-31	-21	0	10	21	74	-18
High Water	Coal	-139	122	-388	9	-342	-109	-120	-47	0	0	0	-3	-84
	CT	-63	26	-5	3	-8	-1	0	0	0	0	0	21	-2
Low Water	Coal	-149	-24	-15	-97	0	1	0	0	-51	56	12	5	-21
	CT	-111	-12	-44	-108	-211	-233	-191	-183	0	66	55	53	-77
Sales to PSW														
High Loads														
Economy Energy		57	339	678	583	453	444	455	-148	-760	-1367	-465	-390	-12
Net Export Sales		782	-341	-727	-822	-952	-961	-225	-148	340	458	260	335	-169
Low Loads														
Economy Energy		351	198	438	567	820	692	598	84	-944	-1592	-596	-503	10

Net Export Sales		1076	-482	-967	-838	-585	-713	-82	84	156	233	129	222	-147
BCH Economy Sales South														
High Loads														
	PNW	-35	-41	-79	25	-36	-69	32	35	-17	4	52	52	-6
	PSW	18	70	95	12	18	43	-3	-36	-10	-52	-43	-41	6
Low Loads														
	PNW	115	-23	9	-7	-21	-26	89	5	-6	16	9	62	19
	PSW	-152	30	47	3	4	-5	12	-10	0	-5	-29	-89	-16

Table F-35

Table 11: Federal Marketing Case B Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	10910	11894	13355	16655	18618	18528	19745	20162	22732	21405	17503	13106	17051
	Coal	5589	5635	5602	5696	5661	5559	4770	3582	3120	4039	4730	5676	4972
	CT	3633	3464	3360	2544	2392	2155	1331	1226	53	767	1313	3072	2109
High Water	Coal	5601	5651	5603	5700	5710	5688	4250	3172	2144	1811	3728	5668	4560
	CT	3937	2554	2339	1782	1690	1440	459	237	0	0	47	1957	1370
Low Water	Coal	5601	5666	5615	5748	5750	5750	5496	4572	4083	5320	5749	5750	5425
	CT	4008	3930	4128	3623	4402	4430	4012	3836	211	2934	3898	4300	3643
Low Loads														
Ave Water	Hydro	12484	12881	14958	16403	18091	17495	17228	17716	20195	19082	16393	12849	16315
	Coal	4271	4244	4072	4050	3658	3392	2733	1799	1245	1841	2355	4082	3145
	CT	198	185	112	126	182	135	123	170	0	11	110	321	139
High Water	Coal	4495	3499	3300	3569	3394	3297	1918	856	859	1008	973	3500	2556
	CT	223	15	4	7	0	0	0	0	0	0	0	13	21
Low Water	Coal	4549	4527	4534	4604	4773	4773	4521	3626	2685	4019	4773	4772	4346
	CT	256	296	277	288	1185	968	730	896	0	61	787	974	560
Sales to PSW														
High Loads														
Economy Energy		1393	1896	1995	2597	2789	3360	3721	3703	3647	3882	3544	2190	2890
Net Export Sales		2493	2551	2650	3252	3444	4015	4376	4803	4747	4982	4644	3290	3768
Low Loads														

Economy Energy		3312	3672	4406	4741	5419	5466	5070	4549	5344	4694	4472	3487	4554
Net Export Sales		4412	4327	5061	5396	6074	6121	5725	5649	6444	5794	5572	4587	5432
BCH Economy Sales South														
High Loads														
	PNW	243	173	231	101	257	208	99	298	274	382	388	387	253
	PSW	320	290	282	127	81	164	27	82	67	119	192	496	187
Low Loads														
	PNW	156	72	99	62	167	245	100	112	31	64	103	305	126
	PSW	247	220	194	114	57	99	40	42	5	9	60	434	127

Table F-36

Table 11-A: Federal Marketing Case B Operation - Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	1.1	-0.4	0.7	-0.1	-1.5	-0.9	0.3	0.2	0.3	0.3	-0.2	-0.1	0.0
	Coal	-0.1	-0.3	-0.1	-0.4	-0.4	-0.8	-3.8	-5.2	0.6	0.7	-4.2	-0.5	-1.2
	CT	-3.2	-5.4	-6.6	-9.7	-1.2	-7.1	-15.6	-9.5	26.2	11.2	-9.3	-3.6	-5.8
High Water	Coal	0.0	0.1	-0.1	-0.4	-0.1	-0.4	-8.1	-7.8	-4.3	0.9	-6.8	-1.1	-2.0
	CT	-3.4	-5.8	-10.2	-9.8	-5.3	-14.8	-39.6	-41.9	0.0	0.0	-53.5	-7.3	-9.7
Low Water	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	-0.1	0.0	0.0	0.0
	CT	-3.1	-3.7	-4.3	-7.0	0.2	0.0	-4.0	-2.1	37.9	15.6	-1.6	-0.9	-1.4
Low Loads														
Ave Water	Hydro	1.5	-1.3	-1.1	-1.2	-1.6	-3.0	-1.7	-0.9	-0.1	0.0	-2.2	0.1	-1.0
	Coal	-1.9	-2.5	-2.9	-3.2	-8.2	-6.2	-8.8	-12.8	-3.0	-1.3	-12.5	-3.9	-5.2
	CT	-26.1	-22.3	-28.7	-25.9	-15.7	-12.9	-25.9	-8.6	0.0	83.3	-7.6	-8.8	-17.8
High Water	Coal	-1.2	-2.7	-14.1	-7.9	-11.2	-1.2	-17.5	-37.8	-0.2	3.7	0.0	-3.0	-7.4
	CT	-18.0	-54.5	-55.6	-74.1	-100.0	-100.0	0.0	0.0	0.0	0.0	0.0	-65.8	-34.4
Low Water	Coal	-1.0	-1.1	-0.9	-1.8	0.0	0.0	0.0	0.0	-0.5	0.9	0.1	0.0	-0.4
	CT	-24.7	-17.1	-15.5	-22.6	-3.0	-3.5	-24.2	-8.7	0.0	110.3	-3.6	-3.7	-9.5
Sales to PSW														
High Loads														
Economy Energy		0.1	9.9	14.6	3.8	-1.8	-3.6	1.1	-9.5	-17.4	-16.0	-8.2	-4.9	-5.4

Net Export Sales		79.2	47.9	52.2	29.9	21.3	15.2	18.9	17.4	7.5	7.8	20.3	42.9	23.4
Low Loads														
Economy Energy		-1.3	0.4	0.3	0.3	-3.6	-6.1	-4.8	-9.7	-15.1	-16.6	-13.0	-7.9	-7.1
Net Export Sales		31.5	18.4	-15.3	14.1	8.1	5.1	7.5	12.1	2.4	3.0	8.4	21.1	10.8
BCH Economy Sales South														
High Loads														
	PNW	3.8	-8.0	-8.0	98.0	5.3	-12.6	8.8	-26.8	-3.9	-0.3	-2.0	12.5	-2.7
	PSW	10.3	30.0	30.0	-2.3	-21.4	-5.2	-53.4	-50.0	-4.3	-6.3	-6.8	-2.7	-1.1
Low Loads														
	PNW	11.4	-2.7	-9.2	5.1	10.6	0.4	-37.1	-34.1	-18.4	3.2	53.7	10.9	-2.3
	PSW	-25.8	-19.1	-16.0	-18.6	-26.9	-20.2	-47.4	-45.5	25.0	-30.8	-45.5	-29.1	-26.2

Table F-37

Table 11-B: Federal Marketing Case B Operation - Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	117	-43	87	-13	-292	-172	66	49	78	59	-28	-7	-8
	Coal	-7	-18	-6	-23	-24	-47	-190	-196	18	27	-209	-31	-58
	CT	-120	-199	-237	-274	-30	-165	-246	-129	11	77	-134	-116	-130
High Water	Coal	0	7	-4	-21	-4	-22	-373	-270	-96	17	-271	-65	-92
	CT	-140	-156	-267	-193	-94	-250	-301	-171	0	0	-54	-155	-148
Low Water	Coal	0	0	0	-2	0	0	0	0	6	-6	0	0	0
	CT	-129	-149	-185	-272	10	-2	-167	-82	58	395	-65	-41	-52
Low Loads														
Ave Water	Hydro	184	-173	-159	-201	286	-533	-290	-169	-12	-9	-368	14	-167
	Coal	-81	-108	-123	-133	-325	-224	-263	-265	-38	-24	-336	-166	-174
	CT	-70	-53	-45	-44	-34	-20	-43	-16	0	5	-9	-31	-30
High Water	Coal	-56	-96	-540	-306	-430	-39	-406	-520	-2	36	0	-110	-205
	CT	-49	-18	-5	-20	-8	-1	0	0	0	0	0	-25	-11
Low Water	Coal	-46	-51	-40	-83	-1	1	1	-1	-13	36	4	0	-16
	CT	-84	-61	-51	-84	-37	-35	-233	-85	0	32	-29	-37	-59
Sales to PSW														
High Loads														

Economy Energy		2	171	254	94	-51	-125	41	-388	-770	-740	-316	-112	-164
Net Export Sales		1102	826	909	749	604	530	696	712	330	360	784	988	714
Low Loads														
Economy Energy		-43	16	15	13	-202	-358	-257	-489	-952	-931	-666	-300	-346
Net Export Sales		1057	671	670	668	453	297	398	611	148	169	434	800	532
BCH Economy Sales South														
High Loads														
	PNW	9	-15	-20	50	13	-30	8	-109	-11	-1	-8	43	-7
	PSW	30	67	65	-3	-22	-9	-31	-82	-3	-8	-14	-14	-2
Low Loads														
	PNW	16	-2	-10	3	16	1	-59	-58	-7	2	36	30	-3
	PSW	-86	-52	-37	-26	-21	-25	-36	-35	1	-4	-50	-178	-45

Table F-38

Table 12: Capacity Ownership - 100% PUB - Power Sale - Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	10803	11962	13330	16673	18660	18625	19711	20220	22721	21360	17580	13115	17063
	Coal	5593	5648	5607	5718	5681	5605	4948	3764	3155	4001	4918	5698	5028
	CT	4331	4224	4158	3376	3099	2882	1944	1619	71	882	1726	3749	2672
High Water	Coal	5601	5654	5607	5715	5716	5702	4562	3457	2208	1770	3981	5696	4639
	CT	4642	3316	3183	2515	2499	2261	855	479	0	0	128	2625	1875
Low Water	Coal	5601	5666	5615	5749	5750	5750	5496	4573	4081	5329	5749	5750	5426
Low Loads	CT	4689	4671	4878	4482	5043	5068	4798	4536	249	3183	4541	4943	4257
Ave Water	Hydro	11997	12876	14659	16864	17926	17765	17744	18194	20205	19137	16850	12844	16422
	Coal	4410	4368	4282	4109	3999	3587	2887	1945	1245	1816	2613	4210	3289
	CT	879	740	688	452	572	401	310	348	1	54	263	714	452
High Water	Coal	4627	3608	3757	3876	3677	3349	2074	1256	861	987	973	3541	2715
	CT	955	185	188	264	111	78	0	0	0	0	0	135	160
Low Water	Coal	4632	4587	4646	4548	4790	4784	4534	3637	2742	3915	4760	4785	4363
	CT	1109	880	1129	746	1915	1703	1534	1577	6	321	1367	1671	1163

Sales to PSW													
High Loads													
Economy Energy	1334	1714	1752	2401	2561	3177	3441	3756	3922	4194	3543	2198	2832
Net Export Sales	1987	1714	2405	3054	3214	3830	4094	4409	4575	4847	4196	2851	3485
Low Loads													
Economy Energy	3023	3317	3874	4512	4982	5167	4938	4712	5674	5087	4681	3433	4451
Net Export Sales	3676	3317	4527	5165	5635	5820	5591	5365	6327	5740	5334	4086	5104
BCH Economy Sales South													
High Loads													
PNW	240	200	265	84	275	217	104	372	244	403	438	379	268
PSW	308	263	252	120	81	153	30	116	69	95	138	461	174
Low Loads													
PNW	172	111	128	74	174	277	158	137	38	84	95	414	155
PSW	234	186	165	78	63	69	39	50	1	5	80	423	116

Table F-39

Table 12-A: Capacity Ownership - 100% PUB - Power Sale - Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	0.1	0.2	0.5	0.0	-1.3	-0.4	0.2	0.5	0.3	0.1	0.3	0.0	0.0
	Coal	-0.1	-0.1	0.0	0.0	-0.1	0.0	-0.2	-0.4	1.7	-0.3	-0.4	-0.2	0.0
	CT	15.4	15.3	15.6	19.8	28.0	24.2	23.3	19.5	69.0	27.8	19.3	17.6	19.3
High Water	Coal	0.0	0.2	0.0	-0.1	0.0	-0.1	-1.3	0.4	-1.4	-1.3	-0.5	-0.6	-0.3
	CT	13.9	22.4	22.1	27.3	40.1	33.8	12.5	17.4	0.0	0.0	26.7	24.3	23.5
Low Water	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0
	CT	13.3	14.5	13.1	15.1	14.8	14.4	14.8	15.8	62.7	25.4	14.6	13.9	15.2
Low Loads														
Ave Water	Hydro	-2.5	-1.4	-3.0	1.6	-2.5	-1.5	1.3	1.7	0.0	0.2	0.5	0.1	-0.4
	Coal	1.3	0.4	2.1	-1.8	0.4	-0.8	-3.6	-5.8	-3.0	-2.6	-2.9	-0.9	-0.9
	CT	228.0	210.9	338.2	165.9	164.8	158.7	86.7	87.1	#######	800.0	121.0	102.8	167.5
High Water	Coal	1.7	0.4	-2.2	0.0	-3.8	0.4	-10.8	-8.7	0.0	1.5	0.0	-1.9	-1.7
	CT	251.1	460.6	1988.9	877.8	1287.5	7700.0	0.0	0.0	0.0	0.0	0.0	255.3	400.0
Low Water	Coal	0.8	0.2	1.6	-3.0	0.3	0.3	0.3	0.3	1.6	-1.7	-0.2	0.3	0.0

	CT	226.2	146.5	244.2	100.5	56.7	69:8	59.3	60.8	#######	1006.9	67.5	65.3	87.9
Sales to PSW														
High Loads														
Economy Energy		-4.1	-0.6	0.6	-4.1	-9.8	-8.8	-6.5	-8.2	-11.2	-9.3	-8.2	-4.5	-7.3
Net Export Sales		42.8	-0.6	38.1	22.0	13.2	9.9	11.2	7.8	3.6	4.9	8.7	23.8	14.1
Low Loads														
Economy Energy		-9.9	-9.3	-1	-4.6	-11.4	-11.3	-7.3	-6.5	-9.9	-9.6	-8.9	-9.3	-9.2
Net Export Sales		9.6	-9.3	3.1	9.2	0.2	-0.1	4.9	6.5	0.5	2.0	3.8	7.9	4.2
BCH Economy Sales South														
High Loads														
	PNW	2.6	6.4	5.6	64.7	12.7	-8.8	14.3	-8.6	-14.4	5.2	10.6	10.2	3.1
	PSW	6.2	17.9	16.1	-7.7	-21.4	-11.6	-48.3	-29.3	-1.4	-25.2	-33.0	-9.6	-7.9
Low Loads														
	PNW	22.9	50.0	17.4	25.4	15.2	13.5	-0.6	-19.4	0.0	35.5	41.8	50.5	20.2
	PSW	-29.7	-31.6	-28.6	-44.3	-19.2	-44.4	-48.7	-35.1	-75.0	-61.5	-27.3	-30.9	-32.6

Table F-40

Table 12-B: Capacity Ownership - 100% PUB - Power Sale - Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	10	25	62	5	-250	-75	32	107	67	14	49	2	4
	Coal	-3	-5	-1	-1	-4	-1	-12	-14	53	-11	-21	-9	-2
	CT	578	561	561	558	677	562	367	264	29	192	279	561	433
High Water	Coal	0	10	0	-6	2	-8	-61	15	-32	-24	-18	-37	-13
	CT	565	606	577	540	715	571	95	71	0	0	27	513	357
Low Water	Coal	0	0	0	-1	0	0	0	1	4	3	0	0	1
	CT	552	592	565	587	651	636	619	618	96	644	578	602	562
Low Loads														
Ave Water	Hydro	-303	-178	-458	260	-451	-263	226	309	-2	46	89	9	-60
	Coal	58	16	87	-74	16	-29	-109	-119	-38	-49	-78	-38	-30
	CT	611	502	531	282	356	246	144	162	1	48	144	362	283
High Water	Coal	76	13	-83	1	-147	13	-250	-120	0	15	0	-69	-46
	CT	683	152	179	237	103	77	0	0	0	0	0	97	128

Low Water	Coal	37	9	72	-139	16	12	14	10	44	-68	-9	13	1
	CT	769	523	801	374	693	700	571	596	6	292	551	660	544
Sales to PSW														
High Loads														
Economy Energy		-57	-11	11	-102	-279	-308	-239	-335	-495	-428	-317	-104	-222
Net Export Sales		596	-11	664	551	374	345	414	318	158	225	336	549	431
Low Loads														
Economy Energy		-332	-339	-517	-216	-639	-657	-389	-326	-622	-538	-457	-354	-449
Net Export Sales		321	-339	136	437	14	-5	264	327	31	115	196	299	204
BCH Economy Sales South														
High Loads														
	PNW	6	12	14	33	31	-21	13	-35	-41	20	42	35	8
	PSW	18	40	35	-10	-22	-20	-28	48	-1	-32	-68	-49	-15
Low Loads														
	PNW	32	37	19	15	23	33	-1	-33	0	22	28	139	26
	PSW	-99	-86	-66	-62	-15	-55	-37	-27	-3	-8	-30	-189	-56

Table F-41

Table 13: Capacity Ownership - 52%/48% GPUB/IOU - Power Sales - Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	10810	11963	13334	16674	18666	18625	19709	20219	22720	21355	17581	13115	17064
	Coal	5593	5649	5607	5718	5684	5607	4962	3796	3161	4021	4938	5701	5036
	CT	4337	4231	4167	3398	3136	2916	1982	1640	71	916	1761	3763	2693
High Water	Coal	5601	5655	5608	5715	5716	5703	4577	3506	2210	1772	4029	5695	4649
	CT	4642	3341	3190	2549	2546	2314	915	538	0	0	147	2676	1905
Low Water	Coal	5601	5666	5615	5750	5750	5750	5496	4573	4081	5326	5749	5750	5426
	CT	4700	4667	4877	4493	5044	5068	4807	4541	249	3195	4547	4944	4261
Low Loads														
Ave Water	Hydro	11948	12859	14614	16915	17872	17761	17762	18233	20208	19135	16857	12848	16418
	Coal	4414	4377	4294	4113	4038	3601	2882	1926	1246	1819	2614	4240	3297
	CT	965	807	753	470	601	410	319	361	1	56	274	749	480
High Water	Coal	4631	3607	3769	3890	3682	3385	2063	1253	861	995	973	3575	2724

CT 1150 189 178 252 111 85 0 0
0 0 0 134 175
Low Water Coal 4632 4619 4646 4561 4789 4783 4533 3636
2755 3919 4769 4785 4369
CT 1206 999 1191 794 1922 1714 1566 1635
6 335 1392 1709 1206
Sales to PSW
High Loads
Economy Energy 1341 1720 1760 2430 2604 3217 3490 3798
3924 4230 3592 2205 2857
Net Export Sales 1994 1720 2413 3083 3257 3870 4143 4451
4577 4883 4245 2858 3510
Low Loads
Economy Energy 3072 3381 3897 4583 4993 5184 4955 4745
5676 5089 4700 3510 4481
Net Export Sales 3725 3381 4550 5236 5646 5837 5608 5398
6329 5742 5353 4163 5134
BCH Economy Sales South
High Loads
PNW 242 204 267 87 280 225 103 375
255 400 442 374 272
PSW 300 257 246 120 81 150 31 104
54 86 130 455 167
Low Loads
PNW 176 114 127 75 177 265 150 142
35 85 97 410 154
PSW 241 191 169 83 62 79 45 50
1 4 76 430 120

Table F-42

Table 13-A: Capacity Ownership - 52%/48% GPUB/IOU - Power Sales - Percentage Change From No Action Case

PNW Generation SEP OCT NOV DEC JAN FEB MAR APR
MAY JUN JUL AUG AVE
High Loads
Ave Water Hydro 0.2 0.2 0.5 0.0 -1.3 -0.4 0.2 0.5
0.3 0.0 0.3 0.0 0.0
Coal -0.1 -0.1 0.0 0.0 0.0 0.0 0.0 0.5
1.9 0.2 0.0 -0.1 0.1
CT 15.6 15.5 15.8 20.6 29.5 25.7 25.7 21.0
69.0 32.8 21.7 18.0 20.3
High Water Coal 0.0 0.2 0.0 -0.1 0.0 -0.1 -1.0 1.9
-1.3 -1.2 0.8 -0.7 -0.1
CT 13.9 23.3 22.4 29.1 42.7 36.9 20.4 31.9
0.0 0.0 45.5 26.7 25.5
Low Water Coal 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0
0.1 0.0 0.0 0.0 0.0
CT 13.6 14.4 13.1 15.4 14.8 14.4 15.0 15.9
62.7 25.8 14.7 13.9 15.3
Low Loads
Ave Water Hydro -2.9 -1.5 -3.3 1.9 -2.7 -1.5 1.4 1.9
0.0 0.2 0.6 0.1 -0.4
Coal 1.4 0.6 2.4 -1.7 1.4 -0.4 -3.8 -6.7
-2.9 -2.5 -2.9 -0.2 -0.7
CT 260.1 239.1 379.6 176.5 178.2 164.5 92.2 94.1
####### 833.3 130.3 112.8 184.0

High Water	Coal	1.8	0.3	-1.8	0.4	-3.7	1.5	-11.2	-8.9	0.0	2.4	0.0	-1.0	-1.3
	CT	322.8	472.7	1877.8	833.3	1287.5	8400.0	0.0	0.0	0.0	0.0	0.0	252.6	446.9
Low Water	Coal	0.8	0.9	1.6	-2.7	0.3	0.2	0.3	0.2	2.1	-1.6	0.0	0.3	0.2
	CT	254.7	179.8	263.1	113.4	57.3	70.9	62.6	66.7	#######	1055.2	70.6	69.0	94.8
Sales to PSW														
High Loads														
Economy Energy		-3.6	-0.3	1.1	-2.9	-8.3	-7.7	-5.2	-7.2	-11.2	-8.5	-6.9	-4.2	-6.5
Net Export Sales		43.3	-0.3	38.6	23.2	14.7	11.0	12.6	8.8	3.6	5.6	10.0	24.1	14.9
Low Loads														
Economy Energy		-8.4	-7.5	-11.3	-3.1	-11.2	-11.0	-7.0	-5.8	-9.8	-9.5	-8.5	-7.3	-8.6
Net Export Sales		11.0	-7.5	3.6	10.7	0.4	0.2	5.3	7.1	0.5	2.1	4.2	9.9	4.8
BCH Economy Sales South														
High Loads														
	PNW	3.4	8.5	6.4	70.6	14.8	-5.5	13.2	-7.9	-10.5	4.4	11.6	8.7	4.6
	PSW	3.4	15.2	13.4	-7.7	-21.4	-13.3	-46.6	-36.6	-22.9	-32.3	-36.9	-10.8	-11.6
Low Loads														
	PNW	25.7	54.1	16.5	27.1	17.2	8.6	-5.7	-16.5	-7.9	37.1	44.8	49.1	19.4
	PSW	-27.6	-29.8	-26.8	-40.7	-20.5	-36.3	-40.8	-35.1	-75.0	-69.2	-30.9	-29.7	-30.2

Table F-43

Table 13-B: Capacity Ownership - 52%/48% GPUB/IOU - Power Sales - Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	17	26	66	6	-244	-75	30	106	66	9	50	2	5
	Coal	-3	-4	-1	-1	-1	1	2	18	59	9	-1	-6	6
	CT	584	568	570	580	714	596	405	285	29	226	314	575	454
High Water	Coal	0	11	1	-6	2	-7	-46	64	-30	-22	30	-38	-3
	CT	565	631	584	574	762	624	155	130	0	0	46	564	387
Low Water	Coal	0	0	0	0	0	0	0	1	4	0	0	0	1
	CT	563	588	564	598	652	636	628	623	96	656	584	603	566
Low Loads														

		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
Ave Water	Hydro	-352	-195	-503	311	-505	-267	244	348	1	44	96	13	-64
	Coal	62	25	99	-70	55	-15	-114	-138	-37	-46	-77	-8	-22
	CT	697	569	596	300	385	255	153	175	1	50	155	397	311
High Water	Coal	80	12	-71	15	-142	49	-261	-123	0	23	0	-35	-37
	CT	878	156	169	225	103	84	0	0	0	0	0	96	143
Low Water	Coal	37	41	72	-126	15	11	13	9	57	-64	0	13	7
	CT	866	642	863	422	700	711	603	654	6	306	576	698	587
Sales to PSW														
High Loads														
Economy Energy		-50	-5	19	-73	-236	-268	-190	-293	-493	-392	-268	-97	-197
Net Export Sales		603	-5	672	580	417	385	463	360	160	261	385	556	456
Low Loads														
Economy Energy		-283	-275	-494	-145	-628	-640	-372	-293	-620	-536	-438	-277	-419
Net Export Sales		370	-275	159	508	25	13	281	360	33	117	215	376	234
BCH Economy Sales South														
High Loads	PNW	8	16	16	36	36	-13	12	-32	-30	17	46	30	12
	PSW	10	34	29	-10	-22	-23	-27	-60	-16	-41	-76	-55	-22
Low Loads														
	PNW	36	40	18	16	26	21	-9	-28	-3	23	30	135	25
	PSW	-92	-81	-62	-57	-16	-45	-31	-27	-3	-9	-34	-182	-52

Table F-44

Table 14: Federal Marketing Case B Combined With Capacity Ownership - 100% PUB - Power Sales

Resource Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	10938	11913	13365	16655	18377	18433	19738	20287	22827	21416	17557	13112	17051
	Coal	5585	5634	5602	5686	5659	5534	4756	3495	3156	4025	4712	5656	4958
	CT	4237	4021	3942	3089	3028	2682	1669	1439	88	953	1589	3588	2527
High Water	Coal	5601	5643	5597	5691	5709	5617	4172	3015	2118	1764	3674	5584	4516
	CT	4555	3049	2994	2350	2260	1944	591	221	0	0	35	2444	1703
Low Water	Coal	5601	5666	5615	5748	5750	5750	5496	4572	4083	5325	5749	5750	5425

	CT	4632	4510	4724	4199	5058	5068	4629	4427	311	3566	4508	4916	4212
Low Loads														
Ave Water	Hydro	12208	12794	14509	16541	17509	17239	17440	17923	20213	19127	16472	12857	16236
	Coal	4311	4227	4147	3955	3756	3341	2539	1667	1206	1755	2280	4019	3100
	CT	737	603	575	347	485	338	255	284	0	63	222	624	378
High Water	Coal	4577	3559	3327	3437	3379	3256	1668	661	858	973	973	3407	2506
	CT	777	172	121	94	92	67	0	0	0	0	0	107	119
Low Water	Coal	4602	4532	4642	4518	4787	4784	4530	3635	2703	3905	4723	4787	4346
	CT	920	758	1057	616	1877	1660	1360	1430	3	362	1300	1583	1077
Sales to PSW														
High Loads														
Economy Energy		1325	1795	1918	2476	2524	3145	3423	3346	3181	3442	3147	2012	2644
Net Export Sales		3150	3175	3298	3856	3904	4525	4803	5171	5006	5267	4972	3837	4247
Low Loads														
Economy Energy		2924	3269	3840	4338	4668	4788	4584	4114	4736	4105	3950	3044	4033
Net Export Sales		4749	4649	5220	5718	6048	6168	5964	5939	6561	5930	5775	4869	5636
BCH Economy Sales South														
High Loads														
	PNW	226	184	253	118	257	247	97	316	262	410	394	476	269
	PSW	305	254	257	109	79	146	16	71	59	88	118	371	157
Low Loads														
	PNW	242	101	138	98	186	307	77	127	34	77	101	443	161
	PSW	99	106	115	41	45	49	23	23	2	4	32	238	65

Table F-45

Table 14-A: Federal Marketing Case B Combined With Capacity Ownership - 100% PUB - Power Sale

Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	1.3	-0.2	0.7	-0.1	-2.8	-1.4	0.3	0.9	0.8	0.3	0.1	0.0	0.0
	Coal	-0.2	-0.3	-0.1	-0.6	-0.5	-1.3	-4.1	-7.5	1.7	0.3	-4.6	-0.0	-1.4
	CT	12.9	9.8	9.6	9.6	25.0	15.6	5.8	6.2	109.5	38.1	9.8	12.5	12.9
High Water	Coal	0.0	0.0	-0.2	-0.5	-0.1	-1.6	-9.8	-12.4	-5.4	-1.7	-8.1	-2.6	-2.9

	CT	11.7	12.5	14.9	19.0	26.7	15.0	-22.2	-45.8	0.0	0.0	-65.3	15.7	12.2
Low Water	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
	CT	12.0	10.6	9.5	7.8	15.2	14.4	10.8	13.0	103.3	40.4	13.8	13.2	14.0
Low Loads														
Ave Water	Hydro	-0.7	-2.0	-4.0	-0.4	-4.7	-4.4	-0.4	0.2	0.0	0.2	-1.7	0.2	-1.5
	Coal	-0.9	-2.9	-1.1	-5.5	-5.7	-7.6	-15.3	-19.2	-6.0	-5.9	-15.3	-5.4	-6.6
	CT	175.0	153.4	266.2	104.1	124.5	118.1	53.6	52.7	0.0	950.0	86.6	77.3	123.7
High Water	Coal	0.6	-1.0	-13.4	-11.3	-11.6	-2.4	-28.2	-52.0	-0.3	0.1	0.0	-5.6	-9.2
	CT	185.7	421.2	1244.4	248.1	1050.0	6600.0	0.0	0.0	0.0	0.0	0.0	181.6	271.9
Low Water	Coal	0.2	-1.0	1.5	-3.6	0.3	0.3	0.2	0.2	0.2	-2.0	-1.0	0.3	-0.4
	CT	170.6	112.3	222.3	65.6	53.6	65.5	41.2	45.8	#######	1148.3	59.3	56.6	74.0
Sales to PSW														
High Loads														
Economy Energy		-4.7	4.1	10.2	-1.1	-11.1	-9.8	-7.0	-18.2	-28.0	-25.5	-18.5	-12.6	-13.4
Net Export Sales		126.5	84.1	89.4	54.1	37.5	29.8	30.5	26.4	13.3	14.0	28.8	66.7	39.0
Low Loads														
___														
Economy Energy		-12.8	-10.6	-12.5	-8.2	-17.0	-17.8	-13.9	-18.3	-24.8	-27.0	-23.1	-19.6	-17.7
Net Export Sales		41.5	27.2	18.9	20.9	7.6	5.9	12.0	17.9	4.2	5.4	12.4	28.6	15.0
BCH Economy Sales South														
High Loads														
	PNW	-3.4	-2.1	0.8	131.4	5.3	3.8	6.6	-22.4	-8.1	7.0	-0.5	38.4	3.5
	PSW	5.2	13.9	18.4	-16.2	-23.3	-15.6	-72.4	-56.7	-15.7	-30.7	-42.7	-27.3	-16.9
Low Loads														
	PNW	72.9	36.5	26.6	66.1	23.2	25.8	-51.6	-25.3	-10.5	24.2	50.7	61.1	24.8
	PSW	-70.3	-61.0	-50.2	-70.7	-42.3	-60.5	-69.7	-70.1	-50.0	-69.2	-70.9	-61.1	-62.2

Table F-46

Table 14-B: Federal Marketing Case B Combined With Capacity Ownership - 100% PUB - Power Sale

Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	145	-24	97	-13	-533	-267	59	174	173	70	26	-1	-8
	Coal	-11	-19	-6	-33	-26	-72	-204	-283	54	13	-227	-51	-72

	CT	484	358	345	271	606	362	92	84	46	263	142	400	288
High Water	Coal	0	-1	-10	-30	-5	-93	-451	-427	-122	-30	-325	-149	-136
	CT	478	339	388	375	476	254	-169	-187	0	0	-66	332	185
Low Water	Coal	0	0	0	-2	0	0	0	0	6	-1	0	0	0
	CT	495	431	411	304	666	636	450	509	158	1027	545	575	517
Low Loads														
Ave Water	Hydro	-92	-260	-608	-63	-868	-789	-78	38	6	36	-289	22	-246
	Coal	-41	-125	-48	-228	-227	-275	-457	-397	-77	-110	-411	-229	-219
	CT	469	365	418	177	269	183	89	- 98	0	57	103	272	209
High Water	Coal	26	-36	-513	-438	-445	-80	-656	-715	-3	1	0	-203	-255
	CT	505	139	112	67	84	66	0	0	0	0	0	69	87
Low Water	Coal	7	-46	68	-169	13	12	10	8	5	-78	-46	15	-16
	CT	580	401	729	244	655	657	397	449	3	333	484	572	458
Sales to PSW														
High Loads														
Economy Energy		-66	70	177	-27	-316	-340	-257	-745	-1236	-1180	-713	-290	-410
Net Export Sales		1759	1450	1557	1353	1064	1040	1123	1080	589	645	1112	1535	1193
Low Loads														
Economy Energy		-431	-387	-551	-390	-953	-1036	-743	-924	-1560	-1520	-1188	-743	-867
Net Export Sales		1394	993	829	990	427	344	637	901	265	305	637	1082	736
BCH Economy Sales South														
High Loads														
	PNW	-8	-4	2	67	13	9	6	-91	-23	27	-2	132	9
	PSW	15	31	40	-21	-24	-27	-42	-93	-11	-39	-88	-139	-32
Low Loads														
	PNW	102	27	29	39	35	63	-82	-43	-4	15	34	168	32
	PSW	-234	-166	-116	-99	-33	-75	-53	-54	-2	-9	-78	-374	-107

Table F-47

Table 15: Federal Marketing Case B Combined With Capacity Ownership - 52%/48% PUB/IOU - Power Sale

Resource Operation - 20 Year Averages - Average MW

PNW Generation	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads													

Ave Water	Hydro	10942	11915	13367	16655	18387	18433	19738	20281	22827	21415	17556	13112	17052
	Coal	5585	5632	5602	5690	5662	5539	4776	3525	3161	4039	4733	5661	4967
	CT	4245	4037	3959	3113	3062	2720	1704	1460	89	991	1621	3604	2550
High Water	Coal	5601	5643	5597	5691	5709	5621	4199	3055	2119	1771	3719	5589	4526
	CT	4556	3057	3029	2391	2312	2026	627	296	0	0	37	2473	1734
Low Water	Coal	5601	5666	5615	5748	5750	5750	5496	4572	4083	5322	5749	5750	5425
	CT	4631	4515	4724	4221	5057	5068	4643	4435	310	3591	4513	4920	4219
Low Loads														
Ave Water	Hydro	12170	12769	14479	16579	17495	17219	17440	17944	20216	19136	16483	12862	16233
	Coal	4317	4238	4165	3952	3786	3357	2546	1658	1206	1756	2285	4052	311
	CT	811	674	616	364	513	358	265	295	0	67	223	654	403
High Water	Coal	4583	3557	3330	3410	3392	3292	1649	646	861	973	973	3412	2506
	CT	946	174	107	100	91	80	0	0	0	0	0	106	133
Low Water	Coal	4605	4544	4642	4542	4787	4784	4530	3635	2717	3955	4751	4789	4357
	CT	1042	801	1138	689	1886	1692	1402	1508	3	389	1287	1631	1122
Sales to PSW														
High Loads														
Economy Energy		1333	1809	1935	2506	2574	3181	3474	3387	3178	3476	3191	2028	2673
Net Export Sales		3158	3189	3315	3886	3954	4561	4854	5212	5003	5301	5016	3853	4276
Low Loads														
Economy Energy		2972	3330	3871	4392	4709	4804	4597	4140	4733	4115	3968	3117	4065
Net Export Sales		4797	4710	5251	5772	6089	6184	5977	5965	6558	5940	5793	4942	5668
BCH Economy Sales South														
High Loads														
	PNW	228	184	253	120	263	250	96	318	268	409	392	472	271
	PSW	298	253	256	109	76	143	16	64	46	73	113	371	151
Low Loads														
	PNW	235	103	140	95	186	300	76	129	33	76	102	437	160
	PSW	114	110	120	47	47	59	24	23	1	3	32	247	69

Table F-48

Table 15-A: Federal Marketing Case B Combined With Capacity Ownership - 52%/48% PUB/IOU - Power Sale

Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	1.4	-0.2	0.7	-0.1	-2.8	-1.4	0.3	0.8	0.8	0.3	0.1	0.0	0.0
	Coal	-0.2	-0.4	-0.1	-0.5	-0.4	-1.2	-3.7	-6.7	1.9	0.7	-4.2	-0.8	-1.3
	CT	13.1	10.2	10.1	10.5	26.4	17.2	8.1	7.7	111.9	43.6	12.0	13.0	13.9
High Water	Coal	0.0	0.0	-0.2	-0.5	-0.1	-1.6	-9.2	-11.2	-5.4	-1.3	-7.0	-2.5	-2.7
	CT	11.7	12.8	16.2	21.1	29.6	19.9	-17.5	-27.5	0.0	0.0	-63.4	17.1	14.2
Low Water	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	-0.1	0.0	0.0	0.0
	CT	11.9	10.7	9.5	8.4	15.1	14.4	11.1	13.2	102.6	41.4	13.9	13.3	14.2
Low Loads														
Ave Water	Hydro	-1.1	-2.2	-4.2	-0.2	-4.8	-4.5	-0.4	0.3	0.0	0.2	-1.7	0.2	-1.5
	Coal	-0.8	-2.6	-0.7	-5.5	-4.9	-7.2	-15.0	-19.7	-6.0	-5.8	-15.1	-4.6	-6.3
	CT	202.6	183.2	292.4	114.1	137.5	131.0	59.6	58.6	0.0	1016.7	87.4	85.8	138.5
High Water	Coal	0.7	-1.1	-13.3	-12.0	-11.3	-1.3	-29.0	-53.1	0.0	0.1	0.0	-5.5	-9.2
	CT	247.8	427.3	1088.9	270.4	1037.5	7900.0	0.0	0.0	0.0	0.0	0.0	178.9	315.6
Low Water	Coal	0.2	-0.7	1.5	-3.1	0.3	0.3	0.2	0.2	0.7	-0.7	-0.4	0.4	-0.1
	CT	206.5	124.4	247.0	85.2	54.3	68.7	45.6	53.7	#######	1241.4	57.7	61.3	81.3
Sales to PSW														
High Loads														
Economy Energy		-4.2	4.9	11.1	0.1	-9.4	-8.7	-5.6	-17.2	-28.1	-24.8	-17.3	-11.9	-12.5
Net Export Sales		127.0	84.9	90.4	55.3	39.2	30.9	31.9	27.4	13.3	14.7	29.9	67.4	40.0
Low Loads														
Economy Energy		-11.4	-8.9	-11.8	-7.1	-16.2	-17.5	-13.7	-17.8	-24.8	-26.8	-22.8	-17.7	-17.0
Net Export Sales		43.0	28.8	19.6	22.1	8.3	6.2	12.2	18.4	4.2	5.6	12.7	30.5	15.7
BCH Economy Sales South														
High Loads														
	PNW	-2.6	-2.1	0.8	135.3	7.8	5.0	5.5	-21.9	-6.0	6.8	-1.0	37.2	4.2
	PSW	2.8	13.5	18.0	-16.2	-26.2	-17.3	-72.4	-61.0	-34.3	-42.5	-45.1	-27.3	-20.1
Low Loads														
	PNW	67.9	39.2	28.4	61.0	23.2	23.0	-52.2	-24.1	-13.2	22.6	52.2	58.9	24.0
	PSW	-65.8	-59.6	-48.1	-66.4	-39.7	-52.4	-68.4	-70.1	-75.0	-76.9	-70.9	-59.6	-59.9

Table F-49

Table 15-B: Federal Marketing Case B Combined With Capacity Ownership - 52%/48% PUB/IOU - Power Sale

Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	149	-22	99	-13	-523	-267	59	168	173	69	25	-1	-7
	Coal	-11	-21	-6	-29	-23	-67	-184	-253	59	27	-206	-46	-63
	CT	492	374	362	295	640	400	127	105	47	301	174	416	311
High Water	Coal	0	-1	-10	-30	-5	-89	-424	-387	-121	-23	-280	-144	-126
	CT	479	347	423	416	528	336	-133	-112	0	0	-64	361	21
Low Water	Coal	0	0	0	-2	0	0	0	0	6	-4	0	0	0
	CT	494	436	411	326	665	636	464	517	157	1052	550	579	524
Low Loads														
Ave Water	Hydro	-130	-285	-638	-25	-882	-809	-78	59	9	45	-278	27	-249
	Coal	-35	-114	-30	-231	-197	-259	-450	-406	-77	-109	-406	-196	-209
	CT	543	436	459	194	297	203	99	109	0	61	104	302	234
High Water	Coal	32	-38	-510	-465	-432	-44	-675	-730	0	1	0	-198	-255
	CT	674	141	98	73	83	79	0	0	0	0	0	68	101
Low Water	Coal	10	-34	68	-145	13	12	10	8	19	-28	-18	17	-5
	CT	702	444	810	317	664	689	439	527	3	360	471	620	503
Sales to PSW														
High Loads														
Economy Energy		-58	84	194	3	-266	-304	-206	-704	-1239	-1146	-669	-274	-381
Net Export Sales		1767	1464	1574	1383	1114	1076	1174	1121	586	679	1156	1551	1222
Low Loads														
Economy Energy		-383	-326	-520	-336	-912	-1020	-730	-898	-1563	-1510	-1170	-670	-835
Net Export Sales		1442	1054	860	1044	468	360	650	927	262	315	655	1155	768
BCH Economy Sales South														
High Loads														
	PNW	-6	-4	2	69	19	12	5	-89	-17	26	-4	128	11
	PSW	8	30	39	-21	-27	-30	-42	-100	-24	-54	-93	-139	-38
Low Loads														
	PNW	95	29	31	36	35	56	-83	-41	-5	14	35	162	31

		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
	PSW	-219	-162	-111	-93	-31	-65	-52	-54	-3	-10	-78	-365	-103

Table F-50

Table 16: Federal Marketing Case A Combined With Capacity Ownership - 100% PUB - Power Sales

Resource Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	11152	11871	13381	16528	18382	18537	19815	20185	22769	21421	17434	13133	17051
	Coal	5592	5648	5607	5702	5675	5563	4836	3698	3202	3976	4954	5697	5012
	CT	4224	4014	3943	3101	3016	2686	1717	1561	86	875	1803	3680	2559
High Water	Coal	5601	5654	5601	5695	5715	5644	4374	3386	2186	1746	4050	5694	4612
	CT	4524	3090	2884	2354	2358	2075	539	411	0	0	171	2593	1750
Low Water	Coal	5601	5666	5615	5748	5750	5750	5496	4573	4084	5331	5749	5750	5426
	CT	4613	4492	4740	4208	5045	5052	4768	4564	300	3548	4574	4924	4236
Low Loads														
Ave Water	Hydro	12328	12838	14437	16714	17777	17748	17790	18281	20188	19097	16869	12854	16410
	Coal	4389	4332	4284	4104	4022	3569	2844	1925	1233	1790	2612	4197	3275
	CT	823	613	703	407	556	353	277	336	0	58	268	708	425
High Water	Coal	4625	3632	3779	3910	3704	3340	2046	1210	861	973	973	3553	2717
	CT	868	220	243	270	163	80	0	0	0	0	0	140	165
Low Water	Coal	4623	4553	4646	4510	4788	4784	4533	3637	2681	3913	4758	4786	4351
	CT	1006	791	1129	619	1857	1641	1358	1480	3	351	1359	1666	1105
Sales to PSW														
High Loads														
Economy Energy		1528	1970	2135	2598	2822	3472	3779	3621	3157	3331	3531	2158	2842
Net Export Sales		2253	2015	2180	2643	2867	3517	3824	4346	4982	5156	4256	2883	3410
Low Loads														
Economy Energy		3261	3700	4278	4902	5418	5647	5479	4757	4737	4114	4704	3426	4539
Net Export Sales		3986	3745	4323	4947	5463	5692	5524	5482	6562	5939	5429	4151	5107
BCH Economy Sales South														
High Loads														
	PNW	197	161	210	104	237	209	100	389	267	388	438	377	257

	PSW	321	280	290	132	110	190	28	96	55	148	153	477	190
Low Loads														
	PNW	195	104	117	74	175	270	157	138	36	86	93	430	156
	PSW	214	196	196	91	70	71	50	38	1	5	83	414	119

Table F-51

Table 16-A: Federal Marketing Case A Combined With Capacity Ownership - 100% PUB - Power Sale

Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	3.3	-0.6	0.9	-0.8	-2.8	-0.9	0.7	0.4	0.5	0.4	-0.6	0.2	0.0
	Coal	-0.1	-0.1	0.0	-0.3	-0.2	-0.8	-2.5	-2.1	3.2	-0.9	0.3	-0.2	-0.4
	CT	12.5	9.6	9.6	10.0	24.5	15.8	8.9	15.2	104.8	26.8	24.6	15.4	14.3
High Water	Coal	0.0	0.2	-0.1	-0.5	0.0	-1.2	-5.4	-1.6	-2.4	-2.7	1.3	-0.7	-0.9
	CT	11.0	14.0	10.7	19.2	32.2	22.8	-29.1	0.7	0.0	0.0	69.3	22.8	15.3
Low Water	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.1	0.0	0.0	0.0
	CT	11.5	10.1	9.9	8.0	14.9	14.0	14.1	16.5	96.1	39.7	15.4	13.4	14.6
Low Loads														
Ave Water	Hydro	0.2	-1.7	-4.5	0.7	-3.3	-1.6	1.6	2.2	-0.1	0.0	0.6	0.1	-0.4
	Coal	0.9	-0.5	2.1	-1.9	1.0	-1.3	-5.1	-6.7	-3.9	-4.0	-2.9	-1.2	-1.3
	CT	207.1	157.6	347.8	139.4	157.4	127.7	66.9	80.6	0.0	866.7	125.2	101.1	151.5
High Water	Coal	1.6	1.0	-1.6	0.9	-3.1	0.1	-12.0	-12.1	0.0	0.1	0.0	-1.6	-1.6
	CT	219.1	566.7	2600.0	900.0	1937.5	7900.0	0.0	0.0	0.0	0.0	0.0	268.4	415.6
Low Water	Coal	0.6	-0.5	1.6	-3.8	0.3	0.3	0.3	0.3	-0.6	-1.8	-0.2	0.3	-0.3
	CT	195.9	121.6	244.2	66.4	52.0	63.6	41.0	50.9	#######	1110.3	66.5	64.8	78.5
Sales to PSW														
High Loads														
Economy Energy		9.8	14.2	22.6	3.8	-0.6	-0.4	2.7	-11.5	-28.5	-27.9	-8.5	-6.3	-6.9
Net Export Sales		62.0	16.8	25.2	5.6	1.0	0.9	3.9	6.2	12.8	11.6	10.3	25.2	11.7
Low Loads														
Economy Energy		-2.8	1.2	-2.6	3.7	-3.6	-3.0	2.9	-5.6	-24.8	-26.9	-8.4	-9.5	-7.4
Net Export Sales		18.8	2.4	-1.5	4.6	-2.8	-2.3	3.7	8.8	4.2	5.6	5.7	9.6	4.2

BCH Economy Sales South

		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
	PNW	-15.8	-14.4	-16.3	103.9	-2.9	-12.2	9.9	-4.4	-6.3	1.3	10.6	9.6	-1.2
	PSW	10.7	25.6	33.6	1.5	6.8	9.8	-51.7	-41.5	-21.4	16.5	-25.7	-6.5	0.5
Low Loads														
	PNW	39.3	40.5	7.3	25.4	15.9	10.7	-1.3	-18.8	-5.3	38.7	38.8	56.4	20.9
	PSW	-35.7	-27.9	-15.2	-35.0	-10.3	-42.7	-34.2	-50.6	-75.0	-61.5	-24.5	-32.4	-30.8

Table F-52

Table 16-B: Federal Marketing Case A Combined With Capacity Ownership - 100% PUB - Power Sale

Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	359	-66	113	-140	-528	-163	136	72	115	75	-97	20	-8
	Cool	-4	-5	-1	-17	-10	-43	-124	-80	100	-36	15	-10	-18
	CT	471	351	346	283	594	366	140	206	44	185	356	492	320
High Water	Coal	0	10	-6	-26	1	-66	-249	-56	-54	-48	51	-39	-40
	CT	447	380	278	379	574	385	-221	3	0	0	70	481	232
Low Water	Coal	0	0	0	-2	0	0	0	1	7	5	0	0	1
	CT	476	413	427	313	653	620	589	646	147	1009	611	583	541
Low Loads														
Ave Water	Hydro	28	-216	-680	110	-600	-280	272	396	-19	6	108	19	-72
	Coal	37	-20	89	-79	39	-47	-152	-139	-50	-75	-79	-51	-44
	CT	555	375	546	237	340	198	111	150	0	52	149	356	256
High Water	Coal	74	37	-61	35	-120	4	-278	-166	0	1	0	-57	-44
	CT	596	187	234	243	155	79	0	0	0	0	0	102	133
Low Water	Coal	28	-25	72	-177	14	12	13	10	-17	-70	-11	14	-11
	CT	666	434	801	247	635	638	395	499	3	322	543	655	486

Sales to PSW	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads													
Economy Energy	137	245	394	95	-18	-13	99	-470	-1260	-1291	-329	-144	-212
Net Export Sales	862	290	439	140	27	32	144	255	565	534	396	581	356
Low Loads													

Economy Energy	-94	44	-113	174	-203	-177	152	-281	-1559	-1511	-434	361	-361
Net Export Sales	631	89	-68	219	-158	-132	197	444	266	314	291	364	207
BCH Economy Sales South													
High Loads													
PNW	-37	-27	-41	53	-7	-29	9	-18	-18	5	42	33	-3
PSW	31	57	73	2	7	17	-30	-68	-15	21	-53	-33	1
Low Loads													
PNW	55	30	8	15	24	26	-2	-32	-2	24	26	155	27
PSW	-119	-76	-35	-49	-8	-53	-26	-39	-3	-8	-27	-198	-53

Table F-53

Table 17: Federal Marketing Case A Combined With Capacity Ownership - 52%/48% PUB/IOU - Power Sale

Resource Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	11164	11876	13379	16527	18394	18551	19799	20189	22774	21416	17423	13134	17052
	Coal	5592	5648	5607	5704	5678	5568	4867	3729	3205	4005	4978	5701	5023
	CT	4234	4028	3958	3130	3053	2726	1775	1587	88	909	1846	3703	2586
High Water	Coal	5601	5654	5601	5703	5715	5644	4427	3402	2186	1747	4087	5695	4622
	CT	4520	3114	2909	2384	2400	2147	627	466	0	0	178	2625	1781
Low Water	Coal	5601	5666	5615	5748	5750	5750	5496	4573	4083	5329	5749	5750	5426
	CT	4621	4495	4743	4226	5046	5048	4794	4576	305	3556	4572	4927	4243
Low Loads														
Ave Water	Hydro	12282	12805	14440	16752	17730	17701	17834	18308	20192	19104	16878	12858	16407
	Coal	4388	4354	4291	4118	4063	3589	2842	1908	1229	1792	2616	4233	3285
	CT	903	699	746	419	590	381	278	352	0	61	277	746	454
High Water	Coal	4623	3626	3790	3927	3731	3382	2043	1217	861	972	973	3593	2728
	CT	1070	230	200	259	148	90	0	0	0	0	0	138	178
Low Water	Coal	4626	4569	4645	4539	4789	4783	4532	3636	2696	3927	4771	4785	4358
	CT	1148	851	1197	666	1870	1699	1381	1556	3	375	1392	1716	1154
Sales to PSW														
High Loads														

Economy Energy		1551	1990	2154	2638	2870	3531	3844	3668	3163	3388	3582	2181	2879
Net Export Sales		2276	2035	2199	2683	2915	3576	3889	4393	4988	5213	4307	2906	3447
Low Loads														
Economy Energy		3299	3779	4323	4964	5444	5647	5514	4782	4734	4123	4726	3511	4574
Net Export Sales		4024	3824	4368	5009	5489	5692	5559	5507	6559	5948	5451	4236	5142
BCH Economy Sales South														
High Loads														
	PNW	191	163	211	111	237	214	101	392	277	371	447	374	257
	PSW	326	280	291	131	110	187	24	85	44	169	145	477	189
Low Loads														
	PNW	197	107	119	73	178	267	154	140	34	86	95	423	156
	PSW	218	199	196	95	70	76	52	41	2	3	78	419	121

Table F-54

Table 17-A: Federal Marketing Case A Combined With Capacity Ownership - 52%/48% PUB/IOU - Power Sale

Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	3.4	-0.5	0.8	-0.8	-2.7	-0.8	0.6	0.4	0.5	0.3	-0.6	0.2	0.0
	Coal	-0.1	-0.1	0.0	-0.3	-0.1	-0.7	-1.9	-1.3	3.3	-0.2	0.8	-0.1	-0.1
	CT	12.8	10.0	10.0	11.1	26.1	17.5	12.6	17.1	109.5	31.7	27.6	16.2	15.5
High Water	Coal	0.0	0.2	-0.1	-0.3	-0.0	-1.2	-4.2	-1.2	-2.4	-2.6	2.2	-0.7	-0.6
	CT	10.9	14.9	11.6	20.7	34.5	27.0	-17.5	14.2	0.0	0.0	76.2	24.3	17.3
Low Water	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0
	CT	11.7	10.2	10.0	8.5	14.9	13.9	14.7	16.8	99.3	40.1	15.4	13.5	14.8
Low Loads														
Ave Water	Hydro	-0.1	-1.9	-4.5	0.9	-3.5	-1.8	1.8	2.4	-0.1	0.1	0.7	0.2	-0.5
	Coal	0.8	0.0	2.3	-1.6	2.0	-0.7	-5.1	-7.6	-4.2	-3.9	-2.8	-0.4	-1.9
	CT	236.9	193.7	375.2	146.5	173.1	145.8	67.5	89.2	0.0	916.7	132.8	111.9	168.6
High Water	Coal	1.6	0.9	-1.3	1.3	-2.4	1.4	-12.1	-11.6	0.0	0.0	0.0	-0.5	-1.2
	CT	293.4	597.0	2122.2	859.3	1750.0	8900.0	0.0	0.0	0.0	0.0	0.0	263.2	456.3
Low Water	Coal	0.7	-0.2	1.6	-3.2	0.3	0.2	0.3	0.2	-0.1	-1.4	0.0	0.3	-0.1

	CT	237.6	138.4	264.9	79.0	53.0	69.4	43.4	58.6	#######	1193.1	70.6	69.7	86.4
Sales to PSW														
High Loads														
Economy Energy		11.5	15.4	23.7	5.4	1.1	1.3	4.5	-10.3	-28.4	-26.7	-7.2	-5.3	-5.7
Net Export Sales		63.6	18.0	26.3	7.2	2.6	2.6	5.7	7.4	12.9	12.8	11.6	26.2	12.9
Low Loads														
Economy Energy		-1.7	3.4	-1.5	5.0	-3.1	-3.0	3.5	-5.1	-24.8	-26.7	-8.0	-7.3	-6.7
Net Export Sales		19.9	4.6	-0.5	5.9	-2.3	-2.3	4.4	9.3	4.2	5.7	6.1	11.9	4.9
BCH Economy Sales South														
High Loads														
	PNW	-18.4	-13.3	-15.9	117.6	-2.9	-10.1	11.0	-3.7	-2.8	-3.1	12.9	8.7	-1.2
	PSW	12.4	25.6	34.1	0.8	6.8	8.1	-58.6	-48.2	-37.1	33.1	-29.6	-6.5	0.0
Low Loads														
	PNW	40.7	44.6	9.2	23.7	17.9	9.4	-3.1	-17.6	-10.5	38.7	41.8	53.8	20.9
	PSW	-34.5	-26.8	-15.2	-32.1	-10.3	-38.7	-31.6	-46.8	-50.0	-76.9	-29.1	-31.5	-29.7

Table F-55

Table 17-B: Federal Marketing Case A Combined With Capacity Ownership 52%/48% PUB/IOU - Power Sale

Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	371	-61	111	-141	-516	-149	120	76	120	70	-108	21	-7
	Coal	-4	-5	-1	-15	-7	-38	-93	-49	103	-7	39	-6	-7
	CT	481	365	361	312	631	406	198	232	46	219	399	515	347
High Water	Coal	0	10	-6	-18	1	-66	-196	-40	-54	-47	88	-38	-30
	CT	443	404	303	409	616	457	-133	58	0	0	77	513	263
Low Water	Coal	0	0	0	-2	0	0	0	1	6	3	0	0	1
	CT	484	416	430	331	654	616	615	658	152	1017	609	586	548
Low Loads														
Ave Water	Hydro	-18	-249	-677	148	-647	-327	316	423	-15	13	117	23	-75
	Coal	36	2	96	-65	80	-27	-154	-156	-54	-73	-75	-15	-34
	CT	635	461	589	249	374	226	112	166	0	55	158	394	285
High Water	Coal	72	31	-50	52	-93	46	-281	-159	0	0	0	-17	-33

CT 798 197 191 232 140 89 0 0
0 0 0 100 146
Low Water Coal 31 -9 71 -148 15 11 12 9
-2 -56 2 13 -4
CT 808 494 869 294 648 696 418 575
3 346 576 705 535
Sales to PSW
High Loads
Economy Energy 160 265 413 135 30 46 164 -423 -
1254 -1234 -278 -121 -175
Net Export Sales 885 310 458 180 75 91 209 302
571 591 447 604 393
Low Loads
Economy Energy -56 123 -68 236 -177 -177 187 -256 -
1562 -1502 -412 -276 -326
Net Export Sales 669 168 -23 281 -132 -132 232 469
263 323 313 449 242
BCH Economy Sales South
High Loads
PNW -43 -25 -40 60 -7 -24 10 -15
-8 -12 51 30 -3
PSW 36 57 74 1 7 14 -34 -79
-26 42 -61 -33 0
Low Loads
PNW 57 33 10 14 27 23 -5 -30
-4 24 28 148 27
PSW -115 -73 -35 -45 -8 -48 -24 -36
-2 -10 -32 -193 -51

Table F-56

Table 18: Federal Marketing Case B Combined With Capacity Ownership - 100% PUB - Seasonal Exchange

Resource Operation - 20 Year Averages - Average MW

PNW Generation SEP OCT NOV DEC JAN FEB MAR APR
MAY JUN JUL AUG AVE
High Loads
Ave Water Hydro 11412 11813 13076 16705 18219 18387 19791 20210
22782 21470 17576 13256 17058
Coal 5585 5637 5598 5664 5640 5494 4795 3568
3139 4074 4783 5679 4971
CT 3679 3477 3238 2239 2306 1993 1359 1214
57 810 1457 3251 2090
High Water Coal 5601 5652 5594 5650 5684 5586 4361 3162
2115 1773 3837 5658 4556
CT 3964 2569 2225 1628 1486 1202 480 256
0 0 41 2169 1335
Low Water Coal 5601 5666 5615 5746 5750 5750 5496 4572
4083 5324 5750 5750 5425
CT 4036 3922 4039 3170 4418 4423 4005 3804
214 3072 4021 4315 3620
Low Loads
Ave Water Hydro 13385 12723 14420 15896 17663 17093 17505 17862
20222 19101 16467 12935 16273
Coal 4046 4284 4053 4039 3598 3277 2571 1735
1225 1783 2317 4101 3086

	CT	146	264	124	132	167	126	132	173	0	15	116	354	146
High Water	Coal	4191	3547	3183	3622	3385	3256	1739	727	857	973	973	3479	2494
	CT	157	26	2	7	0	0	0	0	0	0	0	3	16
Low Water	Coal	4303	4614	4597	4661	4772	4769	4518	3621	2650	4027	4770	4779	4340
	CT	175	386	327	321	1178	956	834	900	0	92	774	1001	579
Sales to PSW														
High Loads														
Economy Energy		1316	1874	2178	2900	2951	3606	3804	3706	3690	3339	3106	1862	2859
Net Export Sales		3141	2529	2108	2830	2881	3536	4459	4806	4790	5164	4931	3687	3737
Low Loads														
Economy Energy		3259	3560	4430	4818	5552	5544	5144	4608	5353	4028	3855	2953	4428
Net Export Sales		5084	4215	4360	4748	5482	5474	5799	5708	6453	5853	5680	4778	5306
BCH Economy Sales South														
High Loads														
	PNW	279	292	298	112	258	230	104	310	277	358	366	417	276
	PSW	300	208	175	70	47	109	18	57	48	104	157	460	146
Low Loads														
	PNW	295	116	127	65	160	249	77	119	32	73	96	320	143
	PSW	101	102	103	36	32	32	20	19	4	5	52	398	76

Table F-57

Table 18-A: Federal Marketing Case Combined With Capacity Ownership - 100% PUB - Seasonal Exchange

Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	5.7	-1.0	-1.4	0.2	-3.7	-1.7	0.6	0.5	0.6	0.6	0.3	1.1	0.0
	Coal	-0.2	-0.3	-0.2	-1.0	-0.8	-2.0	-3.3	-5.6	1.2	1.5	-3.2	-0.5	-1.2
	CT	-2.0	-5.1	-10.0	-20.5	-4.8	-14.1	-13.8	-10.4	35.7	17.4	0.7	2.0	-6.7
High Water	Coal	0.0	0.1	-0.2	-1.2	-0.5	-2.2	-5.7	-8.1	-5.6	-1.2	-4.1	-1.3	-2.1
	CT	-2.8	-5.2	-14.6	-17.6	-16.7	-28.9	-36.8	-37.3	0.0	0.0	-59.4	2.7	-12.1
Low Water	Coal	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
	CT	2.4	-3.8	-6.4	-18.6	0.6	-0.2	-4.2	-2.9	39.9	21.0	1.5	-0.6	-2.0
Low Loads														

		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
Ave Water	Hydro	8.8	-2.5	-4.6	-4.3	-3.9	-5.2	-0.1	-0.1	0.1	0.1	-1.8	0.8	-1.3
	Coal	-7.0	-1.6	-3.4	-3.4	-9.7	-9.4	-14.2	-15.9	-4.5	-4.4	-13.9	-3.5	-7.0
	CT	-45.5	10.9	-21.0	-22.4	-22.7	-18.7	-20.5	7.0	0.0	150.0	-2.5	0.6	-13.6
High Water	Coal	-7.9	-1.3	-17.1	-6.5	-11.5	-2.4	-25.2	-47.2	-0.5	0.1	0.0	-3.6	-9.7
	CT	-42.3	-21.2	-77.8	-74.1	100.0	-100.0	0.0	0.0	0.0	0.0	0.0	-92.1	-50.0
Low Water	Coal	-6.4	0.8	0.5	-0.6	0.0	-0.1	0.0	-0.2	-1.8	1.1	0.0	0.1	-0.5
	CT	-48.5	8.1	-0.3	-13.7	-3.6	-4.7	-13.4	-8.3	0.0	217.2	-5.1	-1.0	-6.5
Sales to PSW														
High Loads														
Economy Energy		-5.4	8.6	25.1	15.9	3.9	3.5	3.4	-9.4	-16.5	-27.8	-19.5	-19.1	-6.4
Net Export Sales		125.8	46.6	21.1	13.1	1.4	1.5	21.2	17.5	8.4	11.7	27.7	60.2	22.3
Low Loads														
Economy Energy		-2.9	-2.6	0.9	1.9	-1.2	-4.8	-3.4	-8.5	-15.0	-28.4	-25.0	-22.0	-9.6
Net Export Sales		51.5	15.3	-0.7	0.4	-2.5	-6.0	8.9	13.3	2.5	4.1	10.5	26.2	8.3
BCH Economy Sales South														
High Loads														
	PNW	19.2	55.3	18.7	119.6	5.7	-3.4	14.3	-23.8	-2.8	-6.5	-7.6	21.2	6.2
	PSW	3.4	-6.7	-19.4	-46.2	-54.4	-37.0	-69.0	-65.2	-31.4	-18.1	-23.8	-9.8	-22.8
Low Loads														
	PNW	110.7	56.8	16.5	10.2	6.0	2.0	-51.6	-30.0	-15.8	17.7	43.3	16.4	10.9
	PSW	-69.7	-62.5	-55.4	-74.3	-59.0	-74.2	-73.7	-75.3	0.0	-61.5	-52.7	-35.0	-55.8

Table F-58

Table 18-B: Federal Marketing Case B Combined With Capacity Ownership - 100% PUB - Seasonal Exchange

Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	619	-124	-192	37	-691	-313	112	97	128	124	45	143	-1
	Coal	-11	-16	-10	-55	-45	-112	-165	-210	37	62	-156	-28	-59
	CT	-74	-186	-359	-579	-116	-327	-218	-141	15	120	10	63	-149
High Water	Coal	0	8	-13	-71	-30	-124	-262	-280	-125	-21	-162	-75	-96
	CT	-113	-141	-381	-347	-298	-488	-280	-152	0	0	-60	57	-183
Low Water	Coal	0	0	0	-4	0	0	0	0	6	-2	1	0	0

		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
	CT	-101	-157	-274	-725	26	-9	-174	-114	61	533	58	-26	-75
Low Loads														
Ave Water	Hydro	1085	-331	-697	-708	-714	-935	-13	-23	15	10	-294	100	-209
	Coal	-306	-68	-142	-144	385	-339	-425	-329	-58	-82	-374	-147	-233
	CT	-122	26	-33	-38	-49	-29	-34	-13	0	9	-3	2	-23
High Water	Coal	-360	-48	-657	-253	-439	-80	-585	-649	-4	1	0	-131	-267
	CT	-115	-7	-7	-20	-8	-1	0	0	0	0	0	-35	-16
Low Water	Coal	-292	36	23	-26	-2	-3	-2	-6	-48	44	1	7	-22
	CT	-165	29	-1	-51	-44	-47	-129	-81	0	63	-42	-10	-40
Sales to PSW														
High Loads														
Economy Energy		-75	149	437	397	111	121	124	-385	-727	-1283	-754	-440	-195
Net Export Sales		1750	804	367	327	41	51	779	715	373	542	1071	1385	683
Low Loads														
Economy Energy		-96	-96	39	90	-69	-280	-183	-430	-943	-1597	-1283	-834	-472
Net Export Sales		1729	559	-31	20	-139	-350	472	670	157	228	542	991	406
BCH Economy Sales South														
High Loads														
	PNW	45	104	47	61	14	-8	13	-97	-8	-25	-30	73	16
	PSW	10	-15	-42	-60	-56	-64	-40	-107	-22	-23	-49	-50	-43
Low Loads														
	PNW	155	42	18	6	9	5	-82	-51	-6	11	29	45	14
	PSW	-232	-170	-128	-104	-46	-92	-56	-58	0	-8	-58	-214	-96

Table F-59

Table 19: Federal Marketing Case B Combined With Capacity Ownership - 52%/48% PUB/IOU - Seasonal Exchange

Resource Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	11348	11838	13125	16710	18249	18416	19766	20200	22778	21462	17569	13227	17057
	Coal	5585	5638	5598	5662	5635	5494	4798	3571	3128	4075	4786	5673	4970
	CT	3641	3510	3321	2350	2315	2035	1366	1226	55	794	1395	3195	2100
High Water	Coal	5601	5651	5597	5641	5675	5583	4351	3173	2121	1769	3789	5651	4550

	CT	3932	2589	2340	1610	1464	1209	475	290	0	0	45	2082	1336
Low Water	Coal	5601	5666	5615	5748	5750	5750	5496	4572	4083	5328	5749	5750	5426
	CT	4040	3963	4083	3389	4422	4429	3996	3810	210	3072	3954	4295	3638
Low Loads														
Ave Water	Hydro	13379	12727	14424	15881	17667	17092	17498	17862	20222	19103	16456	12929	16270
	Coal	4056	4275	4040	4028	3596	3275	2575	1730	1225	1783	2320	4103	3084
	CT	160	238	114	125	162	119	134	168	0	16	122	373	144
High Water	Coal	4206	3555	3184	3631	3387	3251	1739	725	859	973	973	3478	2497
	CT	161	32	1	9	0	0	0	0	0	0	0	9	17
Low Water	Coal	4314	4585	4573	4635	4773	4768	4520	3623	2648	4024	4774	4779	4335
	CT	207	363	304	295	1164	912	848	885	0	97	814	1029	576
Sales to PSW														
High Loads														
Economy Energy		1220	1937	2317	3014	2983	3661	3807	3719	3675	3316	3058	1778	2874
Net Export Sales		3045	2592	2247	2944	2913	3591	4462	4819	4775	5141	4883	3603	3752
Low Loads														
Economy Energy		3265	3530	4426	4796	5555	5545	5150	4602	5354	4030	3854	2956	4422
Net Export Sales		5090	4185	4356	4726	5485	5475	5805	5702	6454	5855	5679	4781	5300
BCH Economy Sales South														
High Loads														
	PNW	281	241	258	93	251	210	110	317	279	377	397	455	273
	PSW	298	263	229	94	58	126	18	58	46	87	132	423	152
Low Loads														
	PNW	313	94	109	56	160	240	80	118	32	74	101	376	145
	PSW	69	123	135	55	41	50	22	23	4	4	43	336	76

Table F-60

Table 19-A: Federal Marketing Case B Combined With Capacity Ownership - 52%/48% PUB/IOU - Seasonal Exchange

Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	5.1	-0.8	-1.1	0.3	-3.5	-1.5	0.4	0.4	0.5	0.5	0.2	0.9	0.0
	Coal	-0.2	-0.3	-0.2	-1.0	-0.9	-2.0	-3.3	-5.5	0.8	1.6	-3.1	-0.6	-1.2

		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
	CT	-3.0	-4.2	-7.7	-16.6	-4.4	-12.3	-13.4	-9.5	31.0	15.1	-3.6	0.2	-6.2
High Water	Coal	0.0	0.1	-0.2	-1.4	-0.7	-2.2	-5.9	-7.8	-5.3	-1.4	-5.3	-1.4	-2.2
	CT	-3.6	-4.5	-10.2	-18.5	-17.9	-28.5	-37.5	-28.9	0.0	0.0	-55.4	-1.4	-12.0
Low Water	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
	CT	-2.3	-2.8	-5.3	-13.0	0.7	-0.1	-4.4	-2.8	37.3	21.0	-0.2	-1.1	-1.5
Low Loads														
Ave Water	Hydro	8.8	-2.5	-4.6	-4.4	-3.9	-5.2	-0.1	-0.1	0.1	0.1	-1.8	0.7	-1.3
	Coal	-6.8	-1.8	-3.7	-3.7	-9.7	-9.4	-14.1	-16.2	-4.5	-4.4	-13.8	-3.4	-7.1
	CT	-40.3	0.0	-27.4	-26.5	-25.0	-23.2	-19.3	-9.7	0.0	166.7	2.5	6.0	-14.8
High Water	Coal	-7.6	-1.1	-17.1	-6.3	-11.4	-2.5	-25.2	-47.3	-0.2	0.1	0.0	-3.7	-9.6
	CT	-40.8	-3.0	-88.9	-66.7	-100.0	-100.0	0.0	0.0	0.0	0.0	0.0	-76.3	-46.9
Low Water	Coal	-6.1	0.2	0.0	-1.1	0.0	-0.1	0.0	-0.1	-1.9	1.0	0.1	0.1	-0.6
	CT	-39.1	1.7	-7.3	-20.7	-4.7	-9.1	-11.9	-9.8	0.0	234.5	-0.2	1.8	-6.9
Sales to PSW														
High Loads														
Economy Energy		-12.3	12.3	33.1	20.4	5.0	5.1	3.5	-9.1	-16.8	-28.3	-20.8	-22.8	-5.9
Net Export Sales		118.9	50.3	29.1	17.6	2.6	3.0	21.3	17.8	8.1	11.2	26.5	56.5	22.8
Low Loads														
Economy Energy		-2.7	-3.4	0.8	1.4	-1.2	-4.8	-3.3	-8.7	-15.0	-28.4	-25.0	-21.9	-9.8
Net Export Sales		51.7	14.5	-0.8	0.0	-2.4	-6.0	9.0	13.2	2.5	4.1	10.5	26.2	8.2
BCH Economy Sales South														
High Loads														
	PNW	20.1	28.2	2.8	82.4	2.9	-11.8	20.9	-22.1	-2.1	-1.6	0.3	32.3	5.0
	PSW	2.8	17.9	5.5	-27.7	-43.7	-27.2	-69.0	-64.6	-34.3	-31.5	-35.9	-17.1	-19.6
Low Loads														
	PNW	123.6	27.0	0.0	-5.1	6.0	-1.6	-49.7	-30.6	-15.8	19.4	50.7	36.7	12.4
	PSW	-79.3	-54.8	-41.6	-60.7	-47.4	-59.7	-71.1	-70.1	0.0	-69.2	-60.9	-45.1	-55.8

Table F-61

Table 19-B: Federal Marketing Case B Combined With Capacity Ownership - 52%/48% PUB/IOU - Seasonal Exchange

Average MW Change From No Action Case

PNW Generation	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads													

Ave Water	Hydro	555	-99	-143	42	-661	-284	87	87	124	116	38	114	-2
	Coal	-11	-15	-10	-57	-50	-112	-162	-207	26	63	-153	-34	-60
	CT	-112	-153	-276	-468	-107	-285	-211	-129	13	104	-52	7	-139
High Water	Coal	0	7	-10	-80	-39	-127	-272	-269	-119	-25	-210	-82	-102
	CT	-145	-121	-266	-365	-320	-481	-285	-118	0	0	-56	-30	-182
Low Water	Coal	0	0	0	-2	0	0	0	0	6	2	0	0	1
	CT	-97	-116	-230	-506	30	-3	-183	-108	57	533	-9	-46	-57
Low Loads														
Ave Water	Hydro	1079	-327	-693	-723	-710	-936	-20	-23	15	12	-305	94	-212
	Coal	-296	-77	-155	-155	-387	-341	-421	-334	-58	-82	-371	-145	-235
	CT	-108	0	-43	-45	-54	-36	-32	-18	0	10	3	21	-25
High Water	Coal	-345	-40	-656	-244	-437	-85	-585	-651	-2	1	0	-132	-264
	CT	-111	-1	-8	-18	-8	-1	0	0	0	0	0	-29	-15
Low Water	Coal	-281	7	-1	-52	-1	-4	0	-4	-50	41	5	7	-27
	CT	-133	6	-24	-77	-58	-91	-115	-96	0	68	-2	18	-43
Sales to PSW														
High Loads														
Economy Energy		-171	212	576	511	143	176	127	-372	-742	-1306	-802	-524	-180
Net Export Sales		1654	867	506	441	73	106	782	728	358	519	1023	1301	698
Low Loads														
Economy Energy		-90	-126	35	68	-66	-279	-177	-436	-942	-1595	-1284	-831	-478
Net Export Sales		1735	529	-35	-2	-136	-349	478	664	158	230	541	994	400
BCH Economy Sales South														
High Loads														
	PNW	47	53	7	42	7	-28	19	-90	-6	-6	1	111	13
	PSW	8	40	12	-36	-45	-47	-40	-106	-24	-40	-74	-87	-37
Low Loads														
	PNW	173	20	0	-3	9	-4	-79	-52	-6	12	34	101	16
	PSW	-264	-149	-96	-85	-37	-74	-54	-54	0	-9	-67	-276	-96

Table F-62

Table 20: Federal Marketing Case B Combined With Assured Delivery - 100% PUB - Seasonal Exchange

Resource Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	11412	11787	13054	16695	18226	18387	19790	20214	22780	21474	17581	13251	17054
	Coal	5585	5636	5599	5659	5633	5495	4772	3556	3111	4064	4779	5678	4964
	CT	3675	3484	3232	2204	2284	1985	1336	1206	52	804	1445	3250	2080
High Water	Coal	5601	5650	5594	5652	5675	5590	4312	3161	2118	1772	3825	5660	4551
	CT	3961	2566	2207	1614	1449	1214	481	263	0	0	42	2177	1331
Low Water	Coal	5601	5666	5615	5745	5750	5750	5496	4572	4080	5323	5750	5750	5425
	CT	4030	3936	4038	3107	4418	4423	3963	3814	204	3071	4010	4317	3611
Low Loads														
Ave Water	Hydro	13389	12719	14406	15898	17652	17110	17481	17867	20221	19095	16466	12935	16270
	Coal	4039	4253	4037	4018	3595	3270	2579	1727	1223	1782	2315	4099	3078
	CT	145	203	112	115	146	102	116	154	0	15	116	353	131
High Water	Coal	4178	3539	3190	3628	3389	3266	1756	729	860	973	973	3469	2496
	CT	156	28	3	5	0	0	0	0	0	0	0	3	16
Low Water	Coal	4294	4554	4555	4584	4775	4770	4520	3625	2640	4034	4773	4779	4325
	CT	176	330	287	261	1048	781	693	790	0	97	773	998	519
Sales to PSW														
High Loads														
Economy Energy		1331	1847	2160	2879	2932	3585	3780	3700	3676	3342	3117	1886	2853
Net Export Sales		3156	2502	2090	2809	2862	3515	4435	4800	4776	5167	4942	3711	3731
Low Loads														
Economy Energy		3268	3518	4420	4821	5533	5559	5128	4599	5353	4022	3860	2963	4421
Net Export Sales		5093	4173	4350	4751	5463	5489	5783	5699	6453	5847	5685	4788	5299
BCH Economy Sales South														
High Loads														
	PNW	287	181	203	106	244	198	100	291	273	367	376	430	254
	PSW	314	312	281	109	82	143	29	82	69	111	163	480	182
Low Loads														
	PNW	305	68	79	44	153	226	76	112	33	74	97	325	132
	PSW	103	198	182	92	50	71	34	36	5	5	52	405	103

Table F-63

Table 20-A: Federal Marketing Case B Combined With Assured Delivery - 100% PUB - Seasonal Exchange

Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	5.7	-1.3	-1.6	0.2	-3.6	-1.7	0.6	0.5	0.6	0.6	0.3	1.1	0.0
	Coal	-0.2	-0.3	-0.2	-1.0	-0.9	-2.0	-3.8	-5.9	0.3	1.3	-3.2	-0.5	-1.3
	CT	-2.1	-4.9	-10.1	-21.8	-5.7	-14.4	-15.3	-11.0	23.8	16.5	-0.1	1.9	-7.1
High Water	Coal	0.0	0.1	-0.2	-1.2	-0.7	-2.1	-6.7	-8.2	-5.4	-1.2	-4.4	-1.3	-2.2
	CT	-2.8	-5.3	-15.3	-18.3	-18.8	-28.2	-36.7	-35.5	0.0	0.0	-58.4	3.1	-12.3
Low Water	Coal	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.1	-0.1	0.0	0.0	0.0
	CT	-2.6	-3.5	-6.4	-20.2	0.6	-0.2	-5.2	-2.7	33.3	21.0	1.2	-0.6	-2.3
Low Loads														
Ave Water	Hydro	8.9	-2.6	-4.7	-4.3	-3.9	-5.1	-0.2	-0.1	0.1	0.0	-1.8	0.8	-1.3
	Coal	-7.2	-2.3	-3.8	-3.9	-9.7	-9.6	-13.9	-16.3	-4.7	-4.5	-14.0	-3.5	-7.3
	CT	-45.9	-14.7	-28.7	-32.4	-32.4	-34.2	-30.1	-17.2	0.0	150.0	-2.5	0.3	-22.5
High Water	Coal	-8.2	-1.6	-16.9	-6.4	-11.4	-2.1	-24.4	-47.0	-0.1	0.1	0.0	-3.9	-9.6
	CT	-42.6	-15.2	-66.7	-81.5	-100.0	-100.0	0.0	0.0	0.0	0.0	0.0	-92.1	-50.0
Low Water	Coal	-6.6	-0.5	-0.4	-2.2	0.0	0.0	0.0	-0.1	-2.1	1.3	0.1	0.1	-0.8
	CT	-48.2	-7.6	-12.5	-29.8	-14.2	-22.1	-28.0	-19.5	0.0	234.5	-5.3	-1.3	-16.2
Sales to PSW														
High Loads														
Economy Energy		-4.3	7.1	24.1	15.0	3.2	2.9	2.7	-9.6	-16.8	-27.7	-19.2	-18.1	-6.6
Net Export Sales		126.9	45.0	20.0	12.2	0.8	0.9	20.5	17.3	8.1	11.8	28.0	61.2	22.2
Low Loads														
Economy Energy		-2.6	-3.8	0.7	2.0	-1.6	-4.6	-3.7	-8.7	-15.0	-28.5	-24.9	-21.8	-9.8
Net Export Sales		51.8	14.1	-0.9	0.5	-2.8	-5.8	8.6	13.1	2.5	3.9	10.6	26.4	8.1
BCH Economy Sales South														
High Loads														
	PNW	22.6	-3.7	-19.1	107.8	0.0	-16.8	9.9	-28.5	-4.2	-4.2	-5.1	25.0	-2.3
	PSW	8.3	39.9	29.5	-16.2	-20.4	-17.3	-50.0	-50.0	-1.4	-12.6	-20.9	-5.9	-3.7
Low Loads														
	PNW	117.9	-8.1	-27.5	-25.4	1.3	-7.4	-52.2	-34.1	-13.2	19.4	44.8	18.2	2.3

PSW	-69.1	-27.2	-21.2	-34.3	-35.9	-42.7	-55.3	-53.2	25.0	-61.5	-52.7	-33.8	-40.1

Table F-64

Table 20-B: Federal Marketing Case: B Combined With Assured Delivery - 100% PUB - Seasonal Exchange

Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	619	-150	-214	27	-684	-313	111	101	126	128	50	138	-5
	Coal	-11	-17	-9	-60	-52	-111	-188	-222	9	52	-160	-29	-66
	CT	-78	-179	-365	-614	-138	-335	-241	-149	10	114	-2	62	-159
High Water	Coal	0	6	-13	-69	-39	-120	-311	-281	-122	-22	-174	-73	-101
	CT	-116	-144	-399	-361	-335	-476	-279	-145	0	0	-59	65	-187
Low Water	Coal	0	0	0	-5	0	0	0	0	3	-3	1	0	0
	CT	-107	-143	-275	-788	26	-9	-216	-104	51	532	47	-24	-84
Low Loads														
Ave Water	Hydro	1089	-335	-711	-706	-725	-918	-37	-18	14	4	-295	100	-212
	Coal	-313	-99	-158	-165	-388	-346	-417	-337	-60	-83	-376	-149	-241
	CT	-123	-35	-45	-55	-70	-53	-50	-32	0	9	-3	1	-38
High Water	Coal	-373	-56	-650	-247	-435	-70	-568	-647	-1	1	0	-141	-265
	CT	-116	-5	-6	-22	-8	-1	0	0	0	0	0	-35	-16
Low Water	Coal	-301	-24	-19	-103	1	-2	0	-2	-58	51	4	7	-37
	CT	-164	-27	-41	-111	-174	-222	-270	-191	0	68	-43	-13	-100
Sales to PSW														
High Loads														
Economy Energy		-60	122	419	376	92	100	100	-391	-741	-1280	-743	-416	-201
Net Export Sales		1765	777	349	306	22	30	755	709	359	545	1082	1409	677
Low Loads														
Economy Energy		-87	-138	29	93	-88	-265	-199	-439	-943	-1603	-1278	-824	-479
Net Export Sales		1738	517	-41	23	-158	-335	456	661	157	222	547	1001	399
BCH Economy Sales South														
High Loads														
	PNW	53	-7	-48	55	0	-40	9	-116	-12	-16	-20	86	-6
	PSW	24	89	64	-21	-21	-30	-29	-82	-1	-16	-43	-30	-7

		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
Low Loads														
	PNW	165	-6	-30	-15	2	-18	-83	-58	-5	12	30	50	3
	PSW	-230	-74	-49	-48	-28	-53	-42	-41	1	-8	-58	-207	-69

Table F-65

Table 21: Federal Marketing Case Combined With Assured Delivery - 52%/48% PUB/IOU - Seasonal Exchange

Resource Operation - 20 Year Averages - Average MW

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	11348	11814	13101	16696	18250	18415	19766	20211	22779	21464	17574	13226	17054
	Coal	5585	5636	5597	5655	5629	5489	4773	3560	3112	4068	4778	5673	4963
	CT	3635	3498	3285	2301	2294	2016	1333	1209	52	787	1388	3196	2083
High Water	Coal	5601	5650	5598	5631	5664	5578	4319	3161	2113	1766	3774	5653	4542
	CT	3928	2569	2306	1585	1433	1201	476	267	0	0	35	2091	1324
Low Water	Coal	5601	5666	5615	5748	5750	5750	5496	4572	4081	5327	5749	5750	5425
	CT	4035	3948	4037	3300	4424	4430	3962	3811	206	3066	3955	4299	3623
Low Loads														
Ave Water	Hydro	13376	12723	14405	15895	17659	17111	17484	17864	20222	19099	16457	12929	16269
	Coal	4050	4253	4025	4009	3589	3253	2576	1726	1224	1784	2320	4102	3076
	CT	160	201	109	114	150	105	116	154	0	16	122	372	135
High Water	Coal	4204	3548	3185	3629	3381	3214	1759	728	859	973	973	3467	2493
	CT	160	25	3	6	0	0	0	0	0	0	0	5	16
Low Water	Coal	4302	4549	4556	4585	4773	4771	4520	3625	2642	4039	4772	4779	4326
	CT	208	325	286	263	1069	801	701	789	0	95	816	1030	532
Sales to PSW														
High Loads														
Economy Energy		1235	1881	2251	2953	2952	3618	3763	3701	3676	3320	3069	804	2851
Net Export Sales		3060	2536	2181	2883	2882	3548	4418	4801	4776	5145	4894	3629	3729
Low Loads														
Economy Energy		3266	3509	4411	4814	5540	5557	5130	4596	5351	4027	3858	2963	4422
Net Export Sales		5091	4164	4341	4744	5470	5487	5785	5696	6451	5852	5683	4788	5300
BCH Economy Sales South														
High Loads														

	PNW	290	173	196	94	234	181	104	291	275	386	411	463	259
	PSW	309	311	287	111	93	155	28	83	68	92	136	444	176
Low Loads														
	PNW	322	64	72	40	148	222	76	112	31	74	102	379	137
	PSW	70	192	196	101	55	88	34	36	5	4	43	343	97

Table F-66

Table 21-A: Federal Marketing Case B Combined With Assured Delivery - 52%/48% PUB/IOU - Seasonal Exchange

Percentage Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	5.1	-1.0	-1.3	0.2	-3.5	-1.5	0.4	0.5	0.6	0.6	0.2	0.9	0.0
	Coal	-0.2	-0.3	-0.2	-1.1	-1.0	-2.1	-3.8	-5.8	0.3	1.4	-3.3	-0.6	-1 3
	CT	-3.1	-4.5	-8.7	-18.3	-5.3	-13.1	-15.5	-10.8	23.8	14.1	-4.1	0.3	-7.0
High Water	Coal	0.0	0.1	-0.2	-1.6	-0.9	-2.3	-6.6	-8.2	-5.7	-1.6	-5.6	-1.4	-2.4
	CT	-3.7	-5.2	-11.5	-19.7	-19.7	-28.9	-37.4	-34.6	0.0	0.0	-65.3	-1.0	-12.8
Low Water	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
	CT	-2.5	-3.2	-6.4	-15.3	0.7	0.0	-5.2	-2.7	34.6	20.8	-0.2	-1.0	-1.9
Low Loads														
Ave Water	Hydro	8.7	-2.5	-4.7	-4.3	-3.9	-5.1	-0.2	-0.1	0.1	0.0	-1.8	0.7	-1.3
	Coal	-6.9	-2.3	-4.1	-4.2	-9.9	-10.0	-14.0	-16.4	-4.6	-4.3	-13.8	-3.4	-7.3
	CT	-40.3	-15.5	-30.6	-32.9	-30.6	-32.3	-30.1	-17.2	0.0	166.7	2.5	5.7	-20.1
High Water	Coal	-7.6	-1.3	-17.1	-6.3	-11.6	-3.7	-24.3	-47.1	-0.2	0.1	0.0	-4.0	-9.7
	CT	-41.2	-24.2	-66.7	-77.8	-100.0	-100.0	0.0	0.0	0.0	0.0	0.0	-86.8	-50.0
Low Water	Coal	-6.4	-0.6	-0.4	-2.2	0.0	0.0	0.0	-0.1	-2.1	1.4	0.1	0.1	-0.8
	CT	-38.8	-9.0	-12.8	-29.3	-12.5	-20.1	-27.2	-19.6	0.0	227.6	0.0	1.9	-14.1
Sales to PSW														
High Loads														
Economy Energy		-11.2	9.0	29.3	18.0	3.9	3.8	2.3	-9.5	-16.8	-28.2	-20.5	-21.6	-6.6
Net Export Sales		120.0	47.0	25.3	15.2	1.5	1.8	20.1	17.4	8.1	11.3	26.8	57.6	22.1
Low Loads														
Economy Energy		-2.7	-4.0	0.5	1.8	-1.4	-4.6	-3.7	-8.8	-15.0	-28.4	-24.9	-21.8	-9.8

		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
Net Export Sales		51.7	13.9	-1.1	0.3	-2.7	-5.8	8.6	13.1	2.5	4.0	10.6	26.4	8.2
BCH Economy Sales South														
High Loads														
	PNW	23.9	-8.0	-21.9	84.3	-4.1	-23.9	14.3	-28.5	-3.5	0.8	3.8	34.6	-0.4
	PSW	6.6	39.5	32.3	-14.6	-9.7	-10.4	-51.7	-49.4	-2.9	-27.6	-34.0	-12.9	-6.9
Low Loads														
	PNW	130.0	-13.5	-33.9	-32.2	-2.0	-9.0	-52.2	-34.1	-18.4	19.4	52.2	37.8	6.2
	PSW	-79.0	-29.4	-15.2	-27.9	-29.5	-29.0	-55.3	-53.2	25.0	-69.2	-60.9	-44.0	-43.6

Table F-67

Table 21-B: Federal Marketing Case B Combined With Assured Delivery - 520%/48% PUB/IOU - Seasonal Exchange

Average MW Change From No Action Case

PNW Generation		SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	AVE
High Loads														
Ave Water	Hydro	555	-123	-167	28	-660	-285	87	98	125	118	43	113	-5
	Coal	-11	-17	-11	-64	-56	-117	-187	-218	10	56	-161	-34	-67
	CT	-118	-165	-312	-517	-128	-304	-244	-146	10	97	-59	8	-156
High Water	Coal	0	6	-9	-90	-50	-132	-304	-281	-127	-28	-225	-80	-110
	CT	-149	-141	-300	-390	-351	-489	-284	-141	0	0	-66	-21	-194
Low Water	Coal	0	0	0	-2	0	0	0	0	4	1	0	0	0
	CT	-102	-131	-276	-595	32	-2	-217	-107	53	527	-8	-42	-72
Low Loads														
Ave Water	Hydro	1076	-331	-712	-709	-718	-917	-34	-21	15	8	-304	94	-213
	Coal	-302	-99	-170	-174	-394	-363	-420	-338	-59	-81	-371	-146	-243
	CT	-108	-37	-48	-56	-66	-50	-50	-32	0	10	3	20	-34
High Water	Coal	-347	-47	-655	-246	-443	-122	-565	-648	-2	1	0	-143	-268
	CT	-112	-8	-6	-21	-8	-1	0	0	0	0	0	-33	-16
Low Water	Coal	-293	-29	-18	-102	-1	-1	0	-2	-56	56	3	7	-36
	CT	-132	-32	-42	-109	-153	-202	-262	-192	0	66	0	19	-87
Sales to PSW														
High Loads														
Economy Energy		-156	156	510	450	112	133	83	-390	-741	-1302	-791	-498	-203
Net Export Sales		1669	811	440	380	42	63	738	710	359	523	1034	1327	675

Low Loads													
Economy Energy	-89	-147	20	86	-81	-267	-197	-442	-945	-1598	-1280	-824	-478
Net Export Sales	1736	508	-50	16	-151	-337	458	658	155	227	545	1001	400
BCH Economy Sales South													
High Loads													
PNW	56	-15	-55	43	-10	-57	13	-116	-10	3	15	119	-1
PSW	19	88	70	-19	-10	-18	-30	-81	-2	-35	-70	-66	-13
Low Loads													
PNW	182	-10	-37	-19	-3	-22	-83	-58	-7	12	35	104	8
PSW	-263	-80	-35	-39	-23	-36	-42	-41	1	-9	-67	-269	-75

Appendix F.

Part 5. PNW Thermal Resource Operation Data Plant-By-Plant

Table F-68 Coal Generation* All Water Years 20 Year Annual Average MW

High Loads Alternative	VALMY 1	VALMY 2	COLSTP 1&2	COLSTP 3&4	CORETTE	BOARD-MAN	CENTR 1&2	BRIDGER 1-4	GEN COAL
NA	110	111	360	1027	57	334	1006	1326	694
FMA	-1	-1	0	0	0	-4	-10	2	-4
CO1SE	0	-1	0	0	0	0	-1	-2	4
CO5SE	0	-1	0	0	0	0	-2	-2	4
AD1SE	0	-1	0	0	0	0	-4	-2	2
AD5SE	0	-1	0	0	0	0	-3	-2	2

FMACO1SE	-1	-1	0	0	0	-3	-7	0	0
FMACO5SE	-1	-1	0	0	0	-3	-7	0	0
FMAAD1SE	-1	-1	0	0	0	-4	-11	0	-2
FMAAD5SE	-1	-1	0	0	0	-4	-11	0	-2
FMB	-2	-2	0	0	-1	-7	-28	-9	-9
CO1PS	-1	-1	0	0	0	-1	-2	0	-2
CO5PS	-1	-1	0	0	0	-1	-1	0	7
FMBCO1PS	-3	-3	0	0	-1	-11	-31	-12	-12
FMBCO5PS	-3	-3	0	0	-1	-10	-33	-12	-3
FMACO1PS	-1	-2	0	0	0	-5	-6	1	-7
FMACO5PS	-1	-2	0	0	0	-4	-6	1	4
FMBCO1SE	-2	-3	0	0	-1	-8	-29	-12	-7
FMBCO5SE	-2	-3	0	0	-1	-7	-29	-12	-7
FMBAD1SE	-2	-3	0	0	-1	-8	-33	-12	-9
FMBAD5SE	-2	-3	0	0	-1	-8	-34	-12	-10

Low Loads Alternative	VALMY 1	VALMY 2	COLSTP 1&2	COLSTP 3&4	CORETTE	BOARD-MAN	CENTR 1&2	BRIDGER 1-4	GEN COAL
NA	61	62	360	948	48	207	539	1088	0
FMA	0	-1	0	-1	0	-4	-9	0	0
CO1SE	-2	-2	0	-2	0	-6	-22	-15	0
CO5SE	-2	-2	0	-2	0	-7	-24	-14	0
AD1SE	-2	-2	0	-2	0	-7	-28	-14	0
AD5SE	-2	-3	0	-2	0	-8	-28	-15	0
FMACO1SE	-3	-3	0	-3	-1	-9	-34	-17	0
FMACO5SE	-3	-3	0	-3	-1	-10	-36	-17	0
FMAAD1SE	-3	-3	0	-3	0	-11	-39	-16	0

FMAAD5SE	-3	-3	0	-3	0	-12	-39	-17	0
FMB	-7	-7	0	-14	-2	-21	-71	-52	0
CO1PS	1	1	0	-10	-1	-4	1	-19	0
CO5PS	1	1	0	-10	-1	-3	9	-19	0
FMBCO1PS	-4	-4	0	-31	-4	-28	-71	-77	0
FMBCO5PS	-4	-4	0	-32	-4	-26	-62	-77	0
FMACO1PS	1	1	0	-12	-1	-6	-4	-22	0
FMACO5PS	1	1	0	-13	-1	-5	5	-23	0
FMBCO1SE	-8	-9	0	-23	-3	-25	-87	-77	0
FMBCO5SE	-8	-8	0	-23	-3	-26	-89	-77	0
FMBAD1SE	-8	-8	0	-23	-3	-27	-94	-77	0
FMBAD5SE	-8	-9	0	-23	-3	-28	-93	-78	0

* Generation of alternatives is compared to No Action.

Table F-69 Coal Generation* High Water Years 20 Year Annual Average MW

High Loads Alternative	VALMY 1	VALMY 2	COLSTP 1&2	COLSTP 3&4	CORETTE	BOARD-MAN	CENTR 1&2	BRIDGER 1-4	GEN COAL
NA	97	97	360	1027	56	305	864	1236	605
FMA	-2	-1	0	0	0	-7	-22	2	-3
CO1SE	-1	0	0	0	0	2	-4	-3	8
CO5SE	-1	0	0	0	0	1	-5	-2	7
AD1SE	-1	0	0	0	0	1	-1	-4	7
AD5SE	-1	0	0	0	0	0	-3	-4	6

FMACO1SE	-1	0	0	0	0	-4	-22	-2	2
FMACO5SE	-1	-1	0	0	0	-4	-20	-1	2
FMAAD1SE	-1	0	0	0	0	-3	-19	-2	2
FMAAD5SE	-1	-1	0	0	0	-5	-23	-2	0
FMB	-3	-3	0	0	0	-12	-52	-11	-12
CO1PS	-1	0	0	0	0	0	-3	-4	-5
CO5PS	-1	0	0	0	0	0	-7	-3	8
FMBCO1PS	-4	-3	0	0	0	-19	-71	-22	-17
FMBCO5PS	-4	-3	0	0	0	-18	-74	-22	-5
FMACO1PS	-1	-1	0	0	0	-5	-16	-4	-13
FMACO5PS	-1	-1	0	0	0	-4	-20	-4	0
FMBCO1SE	-3	-3	0	0	0	-11	-55	-17	-7
FMBCO5SE	-3	-3	0	0	0	-12	-58	-18	-8
FMBAD1SE	-3	-3	0	0	0	-12	-57	-17	-8
FMBAD5SE	-4	-3	0	0	0	-12	-61	-19	-11

Low Loads Alternative	VALMY 1	VALMY 2	COLSTP 1&2	COLSTP 3&4	CORETTE	BOARD-MAN	CENTR 1&2	BRIDGER 1-4	GEN COAL
NA	45	46	360	897	44	128	283	956	0
FMA	-1	0	0	1	0	-5	-15	3	0
CO1SE	-5	-4	0	-2	-1	-9	-35	-14	0
CO5SE	-5	-4	0	-2	-1	-10	-35	-12	0
AD1SE	-5	-4	0	-2	-1	-8	-35	-13	0
AD5SE	-5	-4	0	-2	-1	-11	-35	-11	0
FMACO1SE	-5	-4	0	-1	-1	-15	-47	-14	0
FMACO5SE	-5	-4	0	-1	-1	-15	-44	-14	0
FMAAD1SE	-4	-4	0	-1	-1	-15	-45	-12	0

FMAAD5SE	-5	-4	0	-1	-1	-17	-44	-15	0
FMB	-10	-11	0	-19	-3	-25	-91	-49	0
CO1PS	2	2	0	-9	-2	-10	-12	-19	0
CO5PS	3	3	0	-10	-2	-7	-10	-17	0
FMBCO1PS	-3	-3	0	-33	-5	-35	-95	-83	0
FMBCO5PS	-3	-3	0	-33	-5	-35	-95	-82	0
FMACO1PS	1	2	0	-8	-1	-8	-5	-26	0
FMACO5PS	2	2	0	-8	-2	-6	0	-24	0
FMBCO1SE	-12	-12	0	-22	-4	-32	-111	-76	0
FMBCO5SE	-12	-12	0	-22	-4	-31	-109	-76	0
FMBAD1SE	-11	-11	0	-21	-4	-31	-114	-75	0
FMBAD5SE	-12	-12	0	-21	-4	-33	-112	-76	0

* Generation of alternatives is compared to No Action.

Table F-70 Coal Generation* Low Water Years 20 Year Annual Average MW

High Loads Alternative	VALMY 1	VALMY 2	COLSTP 1&2	COLSTP 3&4	CORETTE	BOARD-MAN	CENTR 1&2	BRIDGER 1-4	GEN COAL
NA	122	121	360	1027	57	372	1187	1366	807
FMA	0	0	0	0	0	0	0	0	0
CO1SE	0	0	0	0	0	0	0	0	0
CO5SE	0	0	0	0	0	0	0	0	0
AD1SE	0	0	0	0	0	0	0	0	0
AD5SE	0	0	0	0	0	0	0	0	0

FMACO1SE	0	0	0	0	0	0	0	0	0
FMACO5SE	0	0	0	0	0	0	0	0	0
FMAAD1SE	0	0	0	0	0	0	0	0	0
FMAAD5SE	0	0	0	0	0	0	0	0	0
FMB	0	0	0	0	0	0	0	0	0
CO1PS	0	0	0	0	0	0	0	0	0
CO5PS	0	0	0	0	0	0	0	0	0
FMBCO1PS	0	0	0	0	0	0	0	0	0
FMBCO5PS	0	0	0	0	0	0	0	0	0
FMACO1PS	0	0	0	0	0	0	0	0	0
FMACO5PS	0	0	0	0	0	0	0	0	0
FMBCO1SE	0	0	0	0	0	0	0	0	0
FMBCO5SE	0	0	0	0	0	0	0	0	0
FMBAD1SE	0	0	0	0	0	0	0	0	0
FMBAD5SE	0	0	0	0	0	0	0	0	0

Low Loads Alternative	VALMY 1	VALMY 2	COLSTP 1&2	COLSTP 3&4	CORETTE	BOARD-MAN	CENTR 1&2	BRIDGER 1-4	GEN COAL
NA	91	91	360	1027	57	344	1024	1363	0
FMA	0	0	0	0	0	-2	-12	1	0
CO1SE	0	0	0	0	0	2	5	0	0
CO5SE	0	0	0	0	0	1	-1	1	0
AD1SE	0	0	0	0	0	1	-6	1	0
AD5SE	0	0	0	0	0	1	-6	1	0
FMACO1SE	0	0	0	0	0	0	-6	1	0
FMACO5SE	0	0	0	0	0	-1	-13	1	0
FMAAD1SE	0	0	0	0	0	-2	-19	1	0

FMAAD5SE	0	0	0	0	0	-3	-18	1	0
FMB	0	0	0	0	0	-3	-13	1	0
CO1PS	1	1	0	0	0	-4	3	0	0
CO5PS	1	1	0	0	0	-3	8	0	0
FMBCO1PS	1	1	0	0	0	-7	-10	0	0
FMBCO5PS	1	1	0	0	0	-5	-2	1	0
FMACO1PS	1	1	0	0	0	-6	-5	0	0
FMACO5PS	1	1	0	0	0	-5	0	0	0
FMBCO1SE	-1	0	0	0	0	-2	-18	0	0
FMBCO5SE	-1	0	0	0	0	-3	-24	1	0
FMBAD1SE	-1	-1	0	0	0	-4	-31	1	0
FMBAD5SE	-1	-1	0	0	0	-5	-30	1	0

* Generation of alternatives is compared to No Action

Table F-71 Combustion Turbine Generation* All Water Years 20 Year Annual Average MW

High Loads Alternative	BeaVER	WHITE- HORN 1	WHITE- HORN 2&3	BETHEL	FREDRICK 1&2	FREDONIA 1&2	NORTH eaST	GEN CTCC
NA	311	6	32	38	34	56	27	1460
FMA	-9	-1	-5	-2	-5	-9	-1	-60
CO1SE	-4	-1	-2	-1	-2	-2	0	-12
CO5SE	-3	-1	-1	1	-1	0	1	-8
AD1SE	-4	-1	-3	-2	-2	-4	-1	-16
AD5SE	-3	-1	-2	-1	-2	-4	0	-10

FMACO1SE	-13	-2	-7	-3	-7	-11	-2	-65
FMACO5SE	-12	-2	-5	-1	-5	-9	-1	-65
FMAAD1SE	-14	-2	-7	-4	-7	-13	-2	-73
FMAAD5SE	-13	-3	-7	-3	-7	-13	-2	-72
FMB	-16	-2	-8	-4	-8	-14	-2	-68
CO1PS	-52	-2	-3	-1	-3	-6	0	504
CO5PS	-49	-2	-3	-1	-3	-6	0	520
FMBCO1PS	-66	-3	-9	-5	-9	-16	-3	412
FMBCO5PS	-64	-3	-9	-5	-9	-16	-3	431
FMACO1PS	-59	-2	-8	-3	-7	-14	-2	424
FMACO5PS	-56	-2	-8	-3	-8	-14	-2	446
FMBCO1SE	-23	-2	-8	-5	-8	-15	-3	-73
FMBCO5SE	-22	-3	-7	-3	-7	-13	-2	-72
FMBAD1SE	-23	-2	-9	-6	-9	-16	-3	-80
FMBAD5SE	-24	-3	-9	-5	-9	-15	-3	-77

Low Loads Alternative	BeaVER	WHITE- HORN 1	WHITE- HORN 2&3	BETHEL	FREDRICK 1&2	FREDONIA 1&2	NORTH eaST	GEN CTCC
NA	105	1	6	7	7	12	5	20
FMA	-7	0	-1	-1	-1	-2	-1	-3
CO1SE	3	0	1	1	1	1	1	2
CO5SE	2	0	1	1	1	1	0	1
AD1SE	-3	-1	0	0	-1	-2	0	0
AD5SE	-2	0	0	0	0	-1	0	0
FMACO1SE	-3	-1	0	1	-1	-1	0	0
FMACO5SE	-4	-1	0	0	-1	-1	0	-1
FMAAD1SE	-10	-1	-1	-1	-2	-3	-1	-2

FMAAD5SE	-9	-1	-1	-1	-1	-2	-1	-2
FMB	-17	-1	-1	-1	-2	-3	-1	-3
CO1PS	5	0	0	0	-1	-1	0	280
CO5PS	14	0	0	1	0	-1	1	296
FMBCO1PS	-16	-1	-2	-1	-2	-4	-1	237
FMBCO5PS	-10	-1	-1	-1	-2	-3	-1	253
FMACO1PS	-2	0	-1	-1	-2	-3	-1	267
FMACO5PS	6	0	-1	0	-1	-2	0	284
FMBCO1SE	-15	-1	-1	0	-2	-3	0	-1
FMBCO5SE	-16	-1	-1	0	-1	-2	0	-3
FMBAD1SE	-21	-1	-2	-1	-3	-5	-1	-4
FMBAD5SE	-20	-1	-2	-1	-2	-4	-1	-3

* Generation of alternatives is compared to No Action

Table F-72 Combustion Turbine Generation* High Water Years 20 Year Annual Average MW

High Loads Alternative	BeaVER	WHITE- HORN 1	WHITE- HORN 2&3	BETHEL	FREDRICK 1&2	FREDONIA 1&2	NORTH eaST	GEN CTCC
NA	254	1	12	17	13	18	14	1024
FMA	-18	0	-4	-2	-4	-6	-1	-84
CO1SE	-4	0	-2	-2	-2	-2	-1	-1
CO5SE	-4	-1	-2	0	-2	-2	-1	-4
AD1SE	-3	0	-2	-2	-2	-3	-1	-5
AD5SE	-2	-1	-2	-1	-2	-3	-1	-6

FMACO1SE	-25	-1	-6	-4	-6	-8	-3	-78
FMACO5SE	-22	-1	-4	-3	-5	-5	-2	-89
FMAAD1SE	-26	0	-6	-4	-6	-8	-3	-85
FMAAD5SE	-26	-1	-5	-3	-5	-6	-2	-99
FMB	-21	-1	-5	-4	-5	-6	-3	-89
CO1PS	-48	0	-2	-1	-2	-2	-1	420
CO5PS	-41	0	-2	0	-2	-1	-1	438
FMBCO1PS	-70	-1	-6	-5	-7	-8	-4	310
FMBCO5PS	-65	-1	-6	-4	-6	-7	-4	332
FMACO1PS	-58	0	-5	-4	-5	-7	-3	330
FMACO5PS	-54	0	-5	-3	-5	-7	-2	356
FMBCO1SE	-41	-1	-6	-6	-6	-8	-5	-92
FMBCO5SE	-39	-1	-6	-4	-6	-7	-4	-97
FMBAD1SE	-39	-1	-6	-6	-6	-9	-5	-98
FMBAD5SE	-39	-1	-6	-5	-6	-8	-5	-105

High Loads Alternative	BeaVER	WHITE- HORN 1	WHITE- HORN 2&3	BETHEL	FREDRICK 1&2	FREDONIA 1&2	NORTH eaST	GEN CTCC
NA	26	0	0	0	0	1	0	3
FMA	-3	0	0	0	0	0	0	-1
CO1SE	-2	0	0	0	0	0	0	-1
CO5SE	0	0	0	0	0	0	0	-1
AD1SE	-2	0	0	0	0	0	0	-1
AD5SE	-2	0	0	0	0	0	0	-1
FMACO1SE	-4	0	0	0	0	0	0	-2
FMACO5SE	-1	0	0	0	0	0	0	-1
FMAAD1SE	-3	0	0	0	0	0	0	-2

FMAAD5SE	-2	0	0	0	0	0	0	-1
FMB	-10	0	0	0	0	-1	0	-2
CO1PS	-1	0	0	0	0	-1	0	128
CO5PS	5	0	0	0	0	-1	1	136
FMBCO1PS	-12	0	0	0	0	-1	0	99
FMBCO5PS	-8	0	0	0	0	-1	0	109
FMACO1PS	-4	0	0	0	0	-1	0	137
FMACO5PS	1	0	0	0	0	-1	0	144
FMBCO1SE	-15	0	0	0	0	0	0	-2
FMBCO5SE	-14	0	0	0	0	0	0	-2
FMBAD1SE	-15	0	0	0	0	0	0	-2
FMBAD5SE	-15	0	0	0	0	0	0	-2

* Generation of alternatives is compared to No Action

Table F-73 Combustion Turbine Generation* Low Water Years 20 Year Annual Average MW

High Loads Alternative	BeaVER	WHITE- HORN 1	WHITE- HORN 2&3	BETHEL	FREDRICK 1&2	FREDONIA 1&2	NORTH eaST	GEN CTCC
NA	407	21	79	75	82	149	53	2330
FMA	0	-3	-8	0	-8	-14	-1	5
CO1SE	0	-2	-3	1	-3	-3	0	-4
CO5SE	0	-2	1	3	0	-2	1	-2
AD1SE	0	-2	-3	1	-3	-6	0	-2
AD5SE	0	-2	-2	2	-2	-5	0	0
FMACO1SE	0	-6	-9	-1	-10	-16	-1	-26

FMACO5SE	0	-5	-7	-2	-7	-11	1	-10
FMAAD1SE	0	-6	-10	-1	-10	-19	-1	-26
FMAAD5SE	0	-6	-9	0	-10	-19	-1	-11
FMB	0	-6	-11	0	-10	-23	-1	-3
CO1PS	-62	-4	-5	1	-5	-12	0	651
CO5PS	-62	-4	-6	1	-5	-12	-1	655
FMBCO1PS	-62	-7	-12	-1	-12	-28	-1	640
FMBCO5PS	-62	-7	-13	-1	-13	-28	-1	649
FMACO1PS	-62	-6	-10	0	-10	-20	-1	646
FMACO5PS	-62	-6	-11	-1	-11	-22	-1	656
FMBCO1SE	0	-6	-11	-2	-11	-23	-1	-22
FMBCO5SE	0	-5	-8	1	-8	-21	0	-15
FMBAD1SE	0	-6	-12	-2	-12	-26	-1	-24
FMBAD5SE	0	-6	-11	-1	-11	-27	-1	-17

Low Loads Alternative	BeaVER	WHITE- HORN 1	WHITE- HORN 2&3	BETHEL	FREDRICK 1&2	FREDONIA 1&2	NORTH eaST	GEN CTCC
NA	317	9	40	42	41	71	29	66
FMA	-15	-1	-6	-4	-5	-9	-3	-2
CO1SE	8	0	1	3	2	6	2	4
CO5SE	4	0	1	2	2	6	1	1
AD1SE	-8	-3	-5	-3	-4	-9	-2	-1
AD5SE	-5	-2	-3	-2	-3	-6	-2	-1
FMACO1SE	-7	-3	-4	0	-3	-5	0	1
FMACO5SE	-12	-3	-4	-2	-3	-5	-1	-1
FMAAD1SE	-27	-5	-12	-7	-11	-22	-5	-2
FMAAD5SE	-24	-5	-10	-6	-9	-18	-4	-2

FMB	-15	-2	-9	-4	-8	-16	-3	-2
CO1PS	6	-2	-7	-3	-6	-11	-2	568
CO5PS	18	-1	-6	-1	-4	-9	0	588
FMBCO1PS	-21	-4	-13	-8	-13	-24	-5	547
FMBCO5PS	-10	-4	-12	-6	-11	-21	-4	570
FMACO1PS	-11	-3	-12	-7	-12	-20	-5	556
FMACO5PS	4	-2	-10	-5	-10	-16	-3	577
FMBCO1SE	-12	-3	-7	-1	-6	-12	-1	1
FMBCO5SE	-13	-4	-6	-2	-5	-10	-1	-1
FMBAD1SE	-26	-5	-15	-6	-14	-28	-4	-2
FMBAD5SE	-24	-5	-12	-6	-11	-24	-4	-2

* Generation of alternatives is Compared to No Action

Table F-74 NFPeis Resource Variable Operating Cost Nominal Mills per kwh

	Plant	1993	2002	2012
EXISTING				
	WNP #2	2.58	4.38	7.74
	COLSTP#1	8.95	14.85	27.45
	COLSTP#2	8.95	14.85	27.45
	COLSTP#3	10.22	17.07	31.62
	COLSTP#4	10.22	17.07	31.62
	CORETTE	12.93	21.12	38.90
	BRIDGER#1	13.11	21.48	39.59
	BRIDGER#2	13.11	21.48	39.59
	BRIDGER#3	13.11	21.48	39.59
	BRIDGER#4	13.11	21.48	39.59
	VALMY#2	17.81	28.88	53.09
	VALMY#1	17.88	28.99	53.29
	CENTR#1	18.73	33.83	61.69
	CENTR#2	18.73	33.83	61.69
	BOARDMAN	18.82	32.87	61.10
	BeaVER	19.05	45.17	88.54
	BETHEL	26.24	63.54	124.84
	NORTHeaST	27.44	62.71	122.41
	WHITHRN#2	30.80	68.82	133.53
	WHITHRN#3	30.80	68.62	133.53
	FRED#1	30.80	68.62	133.53
	FRED#2	30.80	68.62	133.53
	FREDON#1	31.12	69.41	135.08

	FREDON#2	31.12	69.41	135.08
	WHITHRN#1	33.82	75.93	147.89
GENERIC				
	Simple CT	22.66	54.87	107.80
	Combined CT	15.16	36.64	71.97
	Coal	20.75	37.50	68.47
	WNP#3	8.28	15.27	28.74

Table F-75 BPA RESOURCE ADDITIONS FOR HIGH LOADS* AVERAGE MW

OP YeaR	DATE	CONS	RENS	PURCH***	COMBINED CYCLE CT	COAL	WNP 3	TOTAL
1993	Sep-92	64	0	1230				1294
1994	Sep-93	117	95	1230				1442
1995	Sep-94	179	159	1476				1814
1996	Sep-95	248	417	1230				1895
1997	Sep-96	322	417	0	1460			2199
1998	Sep-97	402	417	0	1460			2279
1999	Sep-98	484	417	0	1825			2726
2000	Sep-99	571	417	0	1825			2813
2001	Sep-00	657	417	0	2190			3264
2002	Sep-01	738	552	0	2190			3480
2003	Sep-02	821	556	0	2190			3567
2004	Sep-03	901	560	0	2190		806	4457
2005	Sep-04	988	568	0	2190		806	4552
2006	Sep-05	1080	816	0	2190		806	4892
2007	Sep-06	1168	1010	0	2190		806	5174
2008	Sep-07	1246	1022	0	2190		806	5264

2009	Sep-08	1324	1026	0	2190		806	5346
2010	Sep-09	1397	1026	0	2190		806	5419
2011	Sep-10	1397	1026	0	2190		806	5419
2012	Sep-11	1397	1026	0	2190		806	5419

* BPA loads include generating public net requirements.

** Renewable resources include solar, geothermal, cogeneration, small hydro, etc.
Generic thermal resource capability per unit is; simple cycle CTs - 246 aMW, combined cycle CTs - 365 aMW, coal - 426 aMW, and WNP3 - 806 aMW.

*** Under critical water, these resources are added to create a planning balance in the SAM during those years where planned resource acquisitions are insufficient.
Purchases are modeled as short term increases in CT capability. The price to use this capability is based on the operating cost of a CT. This is a proxy for the cost of short term purchased power if needed by the SAM.

Table F-76 IOU RESOURCE ADDITIONS FOR HIGH LOADS AVERAGE MW*

OP YeaR	DATE	CONS	RENS	PURCH**	COMBINED CYCLE CT	COAL	WNP 3	TOTAL
1993	Sep-92	10	0	984				994
1994	Sep-93	54	15	1230				1299
1995	Sep-94	142	30	1722				1894
1996	Sep-95	250	655	1230				2135
1997	Sep-96	364	975	738	1095			3172
1998	Sep-97	479	2131	0	1095			3705
1999	Sep-98	595	2488	0	1095			4178
2000	Sep-99	717	2828	0	1095			4640
2001	Sep-00	839	3137	0	1095			5071
2002	Sep-01	961	3205	0	1095			5261

2003	Sep-02	1083	3226	0	1095	426		5830
2004	Sep-03	1202	3244	0	1095	852		6393
2005	Sep-04	1308	3281	0	1095	1278		6962
2006	Sep-05	1394	3281	0	1095	1704		7474
2007	Sep-06	1478	3281	0	1095	1704		7558
2008	Sep-07	1563	3585	0	1095	2130		8373
2009	Sep-08	1645	3693	0	1095	2556		8989
2010	Sep-09	1727	3733	0	1095	2556		9111
2011	Sep-10	1727	3733	0	1095	2982		9537
2012	Sep-11	1727	3733	0	1095	3408		9963

* Renewable resources include solar, geothermal, cogeneration, small hydro, etc.
Generic thermal resource capability per unit is; simple cycle CTs - 246 aMW, combined cycle CTs - 365 aMW, coal - 426 aMW, and WNP3 - 806 aMW.

** Under critical water, these resources are added to create a planning balance in the SAM during those years where planned resource acquisitions are insufficient.
Purchases are modeled as short term increases in CT capability. The price to use this capability is based on the operating cost of a CT. This is a proxy for the cost of short term purchased power if needed by the SAM.

Table F-77 BPA RESOURCE ADDITIONS FOR LOW LOADS* AVERAGE MW**

OP YeaR	DATE	CONS	RENS	PURCH***	COMBINED CYCLE CT	COAL	WNP 3	TOTAL
1993	Sep-92	52	0					52
1994	Sep-93	93	95					188
1995	Sep-94	143	154					297
1996	Sep-95	201	412					613
1997	Sep-96	263	412					675

1998	Sep-97	331	412	743
1999	Sep-98	400	412	812
2000	Sep-99	468	412	880
2001	Sep-00	534	412	946
2002	Sep-01	596	412	1008
2003	Sep-02	660	412	1072
2004	Sep-03	663	412	1075
2005	Sep-04	667	412	1079
2006	Sep-05	670	412	1082
2007	Sep-06	673	412	1085
2008	Sep-07	677	412	1089
2009	Sep-08	681	412	1093
2010	Sep-09	685	412	1097
2011	Sep-10	685	412	1097
2012	Sep-11	685	412	1097

* BPA loads include generating public net requirements.

** Renewable resources include solar, geothermal, cogeneration, small hydro, etc. Generic thermal resource capability per unit is; simple cycle CTs - 246 aMW, combined cycle CTs - 365 aMW, coal - 426 aMW, and WNP3 - 806 aMW.

*** Under critical water, these resources are added to create a planning balance in the SAM during those years where planned resource acquisitions are insufficient. Purchases are modeled as short term increases in CT capability. The price to use this capability is based on the operating cost of a CT. This is a proxy for the cost of short term purchased power if needed by the SAM.

Table F-78 IOU RESOURCE ADDITIONS FOR LOW LOADS AVERAGE MW*

OP YeaR	DATE	CONS	RENS	PURCH**	COMBINED CYCLE CT	COAL	WNP 3	TOTAL

1993	Sep-92	2	0		2
1994	Sep-93	18	0		18
1995	Sep-94	51	0		51
1996	Sep-95	108	0		108
1997	Sep-96	182	5		187
1998	Sep-97	261	15		276
1999	Sep-98	326	33		359
2000	Sep-99	381	37		418
2001	Sep-00	440	40		480
2002	Sep-01	504	106		610
2003	Sep-02	569	115		684
2004	Sep-03	625	124		749
2005	Sep-04	679	132		811
2006	Sep-05	738	141		879
2007	Sep-06	796	150		946
2008	Sep-07	851	159	365	1375
2009	Sep-08	900	165	365	1430
2010	Sep-09	949	165	365	1479
2011	Sep-10	949	165	365	1479
2012	Sep-11	949	165	365	1479

* Renewable resources include solar, geothermal, cogeneration, small hydro, etc.
Generic thermal resource capability per unit is; simple cycle CTs - 246 aMW, combined cycle CTs - 365 aMW, coal - 426 aMW, and WNP3 - 806 aMW.

** Under critical water, these resources are added to create a planning balance in the SAM during those years where planned resource acquisitions are insufficient.
Purchases are modeled as short term increases in CT capability. The price to use this capability is based on the operating cost of a CT. This is a proxy for the cost of short term purchased power if needed by the SAM.

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Appendix G. Affected Environment Supporting Documentation

Appendix G. Part 1. PNW Resources Supporting Information

G1

Table G-1 FEDERAL COLUMBIA RIVER POWER SYSTEM GENERAL SPECIFICATIONS OF PROJECTS EXISTING, AUTHORIZED OR LICENSED, AND POTENTIAL NAMEPLATE RATING OF INSTALLATIONS September 24, 1985

```
                     Oper-
                     ating                                     Initial   Number
Number             Number              Number
                     Agency            Stream (if H)      Date in    of 2/
Nameplate  of      Nameplate   of      Nameplate   of     Nameplate
Project        Type     1/    State    City (if Fuel)     Service    Units
Rating-kW  Units   Rating-kW  Units    Rating-kW  Units   Rating-kW
-----------------------------------------------------------------------------------
----------------------------------------------------------
Minidoka        H       BR     ID      Snake             05/07/09     7
13,400                                              7       13,400
Boise Rvr Div   H       BR     ID      Boise             05/00/12     3
1,500                                              3       1,500
```

Black Canyon	H	BR	ID	Payette	12/00/25	2	8,000					2	8,000
Bonneville	H	CE	OR-WA	Columbia	06/06/38	18-2	1,076,600					18-2	1,076,600
Grand Coulee	H	BR	WA	Columbia	09/28/41	24-3	6,163,000			6	4,200,000	30-3	10,363,000
Anderson Rnch	H	BR	ID	S Fk Boise	12/15/50	2	40,000			1	13,500	3	53,500
Hungry Horse	H	BR	MT	S Fk Flathead	10/29/52	4	285,000					4	285,000
Detroit	H	CE	OR	N Santiam	07/01/53	2	100,000						100,000
McNary	H	CE	OR-WA	Columbia	11/06/53	14	980,000	6	747,000 3/			20	1,727,000
Big Cliff	H	CE	OR	N Santiam	06/12/54	1	18,000					1	18,000
Lookout Point	H	CE	OR	M Fk Willamette	12/16/54	3	120,000					3	120,000
Albeni Falls	H	CE	ID	Pend Oreille	03/25/55	3	42,600					3	42,600
Dexter	H	CE	OR	M Fk Willamette	05/19/55	1	15,000					1	15,000
Chief Joseph	H	CE	WA	Columbia	08/28/55	27	2,069,000			13	1,573,000	40	3,642,000
Chandler	H	BR	WA	Yakima	02/13/56	2	12,000					2	12,000
Palisades	H	BR	ID	Snake	02/25/57	4	118,750			2	135,000	6	253,750
The Dalles	H	CE	0R-WA	Columbia	05/13/57	22-2	1,807,000					22-2	1,807,000
Roza	H	BR	WA	Yakima	08/31/58	1	11,250					1	11,250
Ice Harbor	H	CE	WA	Snake	12/18/61	6	602,880					6	602,880
Hills Creek	H	CE	OR	M Fk Willamette	05/02/62	2	30,000					2	30,000
Cougar	H	CE	OR	S Fk McKenzie	02/04/64	2	25,000	1	35,000			3	60,000
Green Peter	H	CE	OR	Middle Santiam	06/09/67	2	80,000					2	80,000
John Day	H	CE	OR-WA	Columbia	07/17/68	16	2,160,000	4	540,000			20	2,700,000
Foster	H	CE	OR	South Santiam	08/22/68	2	20,000					2	20,000
Lower Monumental	H	CE	WA	Snake	05/28/69	6	810,000					6	810,000
Little Goose	H	CE	WA	Snake	05/19/70	6	810,000					6	810,000
Dworshak	H	CE	ID	N Fk Clearwater	09/18/74	3	400,000	3	660,000			6	1,060,000
Grand Coulee PG	PG	BR	WA	Columbia	12/30/74	6	300,000					6	300,000
Lower Granite	H	CE	WA	Snake	04/15/75	6	810,000					6	810,000

Libby H CE MT Kootenai 08/29/75 5
525,000 3 315,000 4/ 8 840,000
Lost Creek H CE OR Rogue 12/01/77 2
49,000 2 49,000
Libby
Reregulating H CE MT Kootenai
3 76,400 3 76,400
Strube H CE OR S Fk McKenzie
1 4,500 1 4,500
Teton H BR ID Teton
3 30,000 3 30,000

Total Number of Units and Nameplate Rating 204-7
19,502,980 24 2,407,900 22 5,921,500 250-7 27,832,380
Total Number of Projects
31 3 0 33

1/ CE - Corps of Engineers, Br - Bureau of Reclamation, BPA - Branch of Generation Planning
2/ Numbers after dashes indicate auxillary units.
3/ McNary Second Powerhouse estimates includes six unites at 124,500 kW each.
4/ Libby Units 6, 7, 8 at 105,000 kW each have been deferred.

G2

Table G-2 EXHIBIT 11 TABLE 1: PACIFIC NORTHWEST REGIONAL ARea SUMMARY OF PACIFIC NORTHWEST REGIONAL LOADS AND RESOURCES UNDER THE PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT H I G H L O A D S

1992 WHITEBOOK: 11/09/92

OPERATING YEAR

RUN DATE: 11/30/92

MEGAWATTS		1993-94 AVG	1994-95 AVG	1995-96 AVG	1996-97 AVG	1997-98 AVG	1998-99 AVG	1999- 0 AVG	2000- 1 AVG	2001- 2 AVG	2002- 3 AVG
LOADS											
1 SYSTEM FIRM LOADS	1/	21738	22329	22901	23470	23991	24501	25042	25595	26073	26618
2 SYSTEM TOTAL LOADS	2/	22585	23176	23749	24317	24839	25349	25890	26441	26896	27440
3 EXPORTS	3/	1147	1148	1140	1178	1202	1317	1447	1434	1432	1508
4 FED DIVERSITY	4/	0	0	0	0	0	0	0	0	0	0
5 FIRM LOADS		22884	23476	24041	24647	25193	25818	26489	27029	27505	28125
6 TOTAL LOADS		23732	24324	24889	25495	26041	26666	27336	27875	28327	28947

RESOURCES

7	MAIN HYDRO	5/	11448	11463	11462	11496	11498	11499	11500	11501	11498	11499
8	INDEPENDENT HYDRO	5/	973	984	984	999	1000	1001	1003	1004	1000	1001
9	SUS. PKNG. ADJUSTMENT	6/	0	0	0	0	0	0	0	0	0	0
			-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
10	TOTAL HYDR0		12421	12447	12446	12495	12498	12500	12503	12505	12498	12500
11	SMALL THERMAL & MISC	7/	108	105	104	119	119	120	121	122	120	120
12	COMBUSTION TURBINES	8/	485	485	485	485	485	485	485	485	485	485
13	RENEWABLES	9/	42	42	43	43	43	43	43	43	44	44
14	COGENERATION	10/	50	50	50	50	50	50	50	50	50	50
15	IMPORTS	11/	1901	1899	1648	1615	1615	1560	1578	1600	1536	1573
16	CENTRALIA		1185	1185	1165	1164	1187	1186	1187	1186	1165	1164
17	TROJAN		713	713	604	0	0	0	0	0	0	0
18	JIM BRIDGER		578	578	584	572	584	584	578	578	584	572
19	COLSTRIP 1 & 2		356	350	349	377	379	379	381	382	377	379
20	BOARDMAN		385	385	385	385	385	385	385	385	385	385
21	VALMY		194	195	195	195	195	194	195	195	195	195
22	COLSTRIP 3		509	505	504	524	525	526	527	529	525	526
23	WNP 2		705	715	747	751	751	751	751	751	751	751
24	C0LSTRIP 4		620	620	621	621	620	621	621	620	621	620
25	FED RESOURCE ACQUIS	12/	0	0	0	0	0	0	0	0	0	0
26	NON-UTILITY GENERATION	13/	502	503	506	516	515	494	494	995	493	494
			-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
27	TOTAL RESOURCES		20754	20777	20436	19912	19951	19878	19899	19926	19829	19858
28	HYD,SM THRM & MISC RES	14/	0	0	0	0	0	0	0	0	0	0
29	LARGE THERMAL RESERVES	15/	0	0	0	0	0	0	0	0	0	0
30	BPA SPINNING RESERVES	16/	0	0	0	0	0	0	0	0	0	0
31	DSI RESERVES	17/	0	0	0	0	0	0	0	0	0	0
22	HYDRO MAINTENANCE	18/	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11

33	NET RESOURCES	20743	20766	20425	19901	19940	19867	19888	19915	19818	19847
34	FIRM SURPLUS/DEFICIT	-2141	-2710	-3616	-4747	-5253	-5951	-6601	-7114	-7687	-8278
35	TOTAL SURPLUS/DEFICIT	-2989	-3558	-4464	-5594	-6101	-6799	-7448	-7960	-8509	-9101

G3

Table G-3 Base Case and Status Quo Resource Stacks

STATUS QUO RESOURCE STACK	BASE CASE RESOURCE STACK
Resources with Priority O (must acquire regardless of cost):	
SF MCS	SF MCS
MF MCS	MF MCS
New Manuf. Housing	New Manuf. Housing
Water Heat	Water Heat
Refrigerators	Refrigerators
Freezers	Freezers
Remaining Discretionary Resources:	
Hydro Eff. Improvements	Hydro Eff. Improvements
Trans. Eff. improvements	Trans. Eff. Improvements
Irrigation	Irrigation
Industrial	Industrial
New Commercial	New Commercial
Hydro 1W	Comm. Lost Ops Existing
Hydro 1E	ME Res Weatherization
Hydro 2W	SF Res Weatherization
Hydro 2E	Comm. Discrete. Existing
Comm. Lost Ops Existing	Hydro 1W
MF Res Weatherization	Hydro 1E
SF Res Weatherization	Hydro 2W
Comm. Discrete. Existing	Hydro 2E
Cogen 1W	Cogen 1W
CTs	Cogen 1E
Cogen 1E	Cogen 2W
Cogen 2W	Hydro 3W
Hydro 3W	WNP1
WNP1	WNP3
WNP3	CTs
Hydro 3E	Hydro 3E
Cogen 2E	Cogen 2E
Coal 1 (E. Mont)	Cogen 3W
Cogen 3W	Hydro 4W
Hydro 4W	Hydro 4E
Hydro 4E	Geothermal 2
Cogen 3E	Cogen 3E

Geothermal 2	Cogen 4W
Coal 2 (E. Wash)	Cogen 4E
Cogen 4W	Wind 1
Coal 3 (E. Ore)	Coal 1 (E. Mont)
Cogen 4E	Wind 2
Coal 4 (Nev)	Coal 2 (E. Wash)
Coal 5 (W. Wash/Ore)	Coal 3 (E. Ore)
Wind 1	Coal 4 (Nev)
Wind 2	Coal 5 (W. Wash/Or)
Geothermal 1	Geothermal 1
Solar 3 (Trough-CT)	Solar 3 (Trough-CT)
Solar 1 (Trough)	Solar 1 (Trough)
Solar 2 (Trough w/HTR)	Solar 2 (Trough w/HTR)

Table G-4 IOU Resource Stack

RESOURCE
Single Family MCS
Multi-Family MCS
New Manufactured Housing
Water Heat
Refrigerators
Freezers
Irrigation
Industrial Conservation
New Commercial Conservation
Hydro 1W
Hydro 1E
Hydro 2W
Hydro 2E
Commercial Lost Ops - Existing
Multi-Family Residential Weatherization
Single-Family Residential Weatherization
Existing Commercial Discretionary Conservation
Cogeneration 1W
Combined-Cycle CTs
Cogeneration 1E
Cogeneration 2W
Hydro 3W
Hydro 3E
Cogeneration 2E
Coal 1 (Eastern Montana)
Cogeneration 3W
Hydro 4E
Cogeneration 3E
Coal 2 (Eastern Washington)
Cogen 4W
Coal 3 (Eastern Oregon)
Cogen 4E
Coal 4 (Nevada)
Coal 5 (Western Washington/Oregon)
Wind 1
Wind 2

Table G-5 DRAFT PROPOSED OR POTENTIAL TRANSACTIONS DRAFT By NEW INTERTIE CAPACITY OWNERS March 5, 1993

```
       Name            Type Resource      Capacity    Location       Owned By
In FRE?   Existing Or?    Permits, Etc?   Transaction?   Type Exch.
  ------------------  -----------------  ----------  -------------  ---------
-------  --------  --------------  --------------  -------------  ----------
                                              (MW)

  1.   Clark           Cogen./CCCT              75 1/ Goldendale/    Utility
No       Under Const.   In Pl ace       Plan Sale     Unknown 2/
                                                  Harvalum
3/15/93
  2.   Emerald         Cogen./CCCT             130 1/ Goldendale/    Utility
No       Under Const.   In Place        Plan Sale     Unknown 2/
                                                  Harvalum
3/15/93
* 3.   Snohomish       Cogen./Wood Waste        43    Everett/       Utility
No       Planned        3/93            Sale          N/A
                                                  Scott Paper
On-Line 4/95
  4.   Mason Co.       #1 Cogen./Wood Waste     14    Mason Co./     Utility
No       Planned        Underway        Sale          N/A
                                                  Shelton
                       #2 Cogen./CCCT           49    Mason Co./Wa.  Utility
No       Planned        Underway        Sale
                                                  Corrections
  5.   Gray's Harbor  Various Cogen. 3/     10-80    Grays Harbor   Unsure
No       Planned        Underway        Sale or       Unsure
                                                  Co.
Exchange
* 6.   PacifiCorp      System Power         75-150    N/A            Utility
No 4/    Existing       N/A             Sale          N/A
* 7.   Seattle         System (hydro)           60    Boundary       Utility
Yes      Existing       N/A             Exchange      Seasonal
                       System (hydro)          100    SCBID
Irrigation Dist.    Yes      Existing       N/A           Cap. Sale
* 8.   Tacoma          System (hydro) 5/        74 6/ SCBID
Irrigation Dist.    No       Existing       N/A           Sale
N/A
                                                  CSPE Share     Utility
No       Existing       N/A
* 9.   PNGC            Coal-fired steam         51    Boardman       Utility
No       Existing       N/A             25 yr.        N/A

Cap.& Energy

Sale
* 10.  EWEB            2 Cogen./Wood Waste      50 7/ Springfield/   #3/Weyco
No       Existing       In Place        5 yr. Sale    N/A
                       1 Steam Plant                  Weyco #3 & 4   Steam
Plant &
```

Eugene/

#4/Utility

Willamette Stm

* 11. Puget Undefined 300 8/

5 yr. Seasonal

Cap. & Energy

Exchange

1/ Capacity of resource is 205 MW, ownership to be shared by Clark and Emerald as indicated.

2/ Clark and Emerald plan a joint sale. However, an exchange is possible if sale not completed.

3/ Grays Harbor is considering wood waste and natural gas, located at the ITT Rayonier, or at Morton International.

4/ PacifiCorp does not consider this question pertinent for system sale.

5/ Existing contract with WAPA based on system sale - currently using AD contract.

6/ Tacoma has requested 40-50 MW of capacity, the difference between allocation and sale will continue as AD contract.

7/ EWEB has requested a 50 MW allocation. Resources total 88.7 MW, 51.2 MW from Weyco #4, 12.5 MW from Weyco #3 and 25 MW from Willamette Steam.

8/ Puget has requested 400 MW.

MMcFarland:sc:3688:01/05/93 (VS10-PMTI-8979D)

G6

Table G-6 Federal and Pacific Northwest Air Quality Standards

Pollutant	National Primary	National Secondary	Washington	Montana	Oregon	Idaho
PM10						
Annual Arith Mean	50 ug/mE(3) (a)	50 ug/mE(3)	50 ug/mE(3)	50 ug/mE(3)	50 ug/mE(3)	50 ug/mE(3)
24-Hour Average	150 ug/mE(3)	150 ug/mE(3)	150 ug/mE(3)	150 ug/mE(3)	150 ug/mE(3)	150 ug/mE(3)
Sulfur Dioxide						
Annual Average	0.03 ppm (b)	0.02 ppm		0.02 ppm	0.10 ppm	0.03 ppm (b)
24-Hour Average	0.14 ppm		0.10 ppm	0.5 ppm (e)	0.50 ppm	0.14 ppm
3-Hour Average		0.50 ppm		0.5 ppm (e)		
1-Hour Average			0.40 ppm (c)			
Carbon Monoxide						
8-Hour Average	9 ppm	9 ppm	9 ppm	9 ppm	9 ppm	9 ppm
1-Hour Average	35 ppm	35 ppm	35 ppm		35 ppm	35 ppm
Ozone						
1-Hour Average (d)	0.12 ppm	0.12 ppm	0.12 ppm	0.12 ppm	0.12 ppm	0.12 ppm
Nitrogen Dioxide						
Annual Average	0.053 ppm	0.05 ppm	0.05 ppm	0.05 ppm	0.053 ppm	0.053 ppm

Lead
Quarterly Average 150 ug/mE(3)
150 ug/mE(3) 150 ug/mE(3)
Hydrogen Sulfide
1-Hour Average 0.05 ppm (e)
0.05 ppm (e)

(a) micrograms per cubic meter
(b) parts per million
(c) 0.25 ppm not to be exceeded more than two times in any seven consecutive days.
(d) Not to be exceeded on more than 1 calendar day per year.
(e) Not to be exceeded more than once per year.

Appendix G. Part 2. PSW Resources Supporting Information

Table G-7 Dependable Capacity in 1992, 1996, 2003 and 2011 1/ (MW)

	PG&E				SCE				SDG&E			
	1992	1996	2003	2011	1992	1996	2003	2011	1992	1996	2003	2011
UTILITY OWNED RESOURCES												
Nuclear	2,160	2,160	2,160	2,160	2,541	2,541	2,541	2,541	517	430	430	430
Coal	0	0	0	0	1,615	1,615	1,615	1,615	0	0	0	0
Oil/Gas Steam-Active	6,801	6,337	5,657	5,657	7,076	6,950	6,589	6,014	1,611	1,506	1,335	1,335
Short-Term Reserve 2/	0	0	0	0	1,334	1,334	1,334	1,334	0	0	0	0
Lg-Trm Reserves 2/	412	876	1,342	1,342	292	292	292	292	230	230	230	230
Combustion Turbines	394	394	394	394	580	580	580	580	332	332	332	332
Combined Cycle	0	0	870	1,305	1,012	1,412	2,397	4,161	0	273	1,600	1,600

Geothermal	791	601	391	255	0	0	0	0	0	0	0	0
Hydroelectric	4,567	4,586	4,586	4,586	1,014	1,014	1,014	1,014	0	0	0	0
Pumped Storage	1,186	1,186	1,186	1,186	89	89	89	89	0	0	0	0
NON-UTILITY OWNED RESOURCES												
Fossil Cogeneration-QF	1,881	1,934	1,934	1,934	2,068	2,068	2,068	2,068	119	179	179	179
Self-Generation	704	812	842	861	0	0	0	0	70	71	76	79
Biomass-QF	604	618	618	618	298	298	298	298	8	8	17	17
Self-Generation	90	90	90	90	533	533	533	533	0	0	0	0
Geothermal-QF	146	186	186	186	634	634	634	634	0	0	0	0
Hydroelectric-QF	69	69	69	69	60	60	60	60	2	2	2	2
Wind-QF	170	170	170	170	128	128	128	128	0	0	0	0
Solar-QF	2	2	2	2	369	369	369	369	0	0	0	0
Imports												
PNW	808	728	728	728	941	949	948	7	245	115	69	69
ISW and Mexio	0	0	0	0	631	714	646	563	884	100	0	0
CA	0	0	0	0	624	624	624	0	0	0	0	0
UNCOMMITTED & PENDING RESOURCES												
Demand Side Mgmt	417	1,380	3,134	4,620	1,073	1,449	3,460	5,978	108	292	420	572
PNW "Spot Capacity" and Exchanges 3/	1,200	1,200	1,200	1,200	0	600	600	600	100	100	100	100
Pending Resources	0	411	473	473	0	410	536	611	2	2	2	2
Selected Res. Additions	0	0	23	423	0	0	3	350	0	960	360	1.560
TOTAL RESOURCES	21,990	22,864	24,713	26,917	21,286	23,037	26,079	28,213	3,998	4,340	4,922	6,277

1/ Draft Final CEC 1992 Electricity Report Appendices, Appendix B. Resource Accounting Tables.

2/ Oil/Gas reserves excluded from Total Resources.
3/ "Spot Capacity" provides system operational flexibility and serves needle peak needs.

Table G-8 Dependable Capacity in 1 and 2011 1/ (MW)

	SMUD				LADWP				BGP				NCPA			
	1992	1996	2003	2011	1992	1996	2003	2011	1992	1996	2003	2011	1992	1996	2003	2011
UTILITY OWNED RESOURCES																
Nuclear	0	0	0	0	368	368	368	368	30	30	30	30	0	0	0	0
Coal	0	0	0	0	1,507	1,507	1,507	1,507	138	138	69	69	0	0	0	0
Oil/Gas Steam-Active	0	0	0	0	2,890	2,711	2,632	2,632	409	409	409	409	0	0	0	0
Short-Term Reserve 2/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lg-Trm Reserves 2/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combustion Turbines	49	49	49	49	76	76	76	76	168	168	168	168	90	90	90	90
Combined Cycle	0	0	0	0	0	240	760	760	106	106	106	106	0	0	0	0
Geothermal	95	116	98	78	0	0	0	0	0	0	0	0	109	68	28	13
Hydroelectric	642	642	642	642	200	200	200	200	2	2	2	2	142	142	142	142
Pumped Storage	0	0	0	0	1,247	1,247	1,247	1,247	0	0	0	0	0	0	0	0
NON-UTILITY OWNED RESOURCES																
Fossil Cogeneration-QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Self-Generation	0	0	0	0	214	254	254	254	0	0	0	0	0	0	0	0
Biomass-QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Self-Generation	0	0	0	0	35	35	35	35	0	0	0	0	0	0	0	0
Geothermal - QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydroelectric - QF	0	0	0	0	1	1	1	1	0	0	0	0	0	0	0	0
Wind - QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Solar - QF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports																
PNW	96	96	96	96	105	105	105	105	181	172	171	152	0	30	30	30
ISW and Mexico	0	0	0	0	919	919	919	919	40	40	40	40	0	0	0	0
CA	1,186	1,041	360	360	0	0	0	0	15	15	15	15	317	317	317	317
UNCOMMITTED & PENDING RESOURCES																
Demand Side Mgmt	181	434	813	1,116	161	339	878	1,530	0	0	0	0	8	17	32	48
PNW "Spot Capacity" and Exchanges 3/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pending Resources	0	558	768	768	0	95	163	163	0	0	0	0	0	77	77	77
Selected Res. Additions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL RESOURCES	2,249	2,936	2.826	3,109	7,723	8,097	9,145	9,797	1,089	1,080	1,010	991	666	741	716	717

1/ Draft Final CEC 1992 Electricity Report Appendices, Appendix B, Resource Accounting Tables.
2/ Oil/Gas reserves excluded from Total Resources.
3/ "Spot Capacity" provides system operational flexibility and serves needle peak needs.

G-9. Utility Specific Needs Assessment Information

Pacific Gas and Electric (PG&E) should have sufficient capacity to meet its reserve margin through 2009 due to current abundant resources and its intent to aggressively pursue DSM programs. By 2003 PG&E plans to save 3,134 MW through its DSM programs, utilize 1,200 MW of Pacific Northwest summer capacity, (purchased on a short-term basis) and acquire 385 MW of cost-effective resources currently considered "pending resources."

Southern California Edison's (SCE) planning area will have adequate capacity resources available to meet its demand through the year 2001. Future resource planning decisions must take into account SCE's partial requirement customers (called Resale Cities) which are pursuing some independent resource planning and the air quality constraints imposed by the South Coast Air Quality Management District (SCAQMD) and Ventura Air Quality

Management District. Given current forecasts of demand, SCE intends to pursue an aggressive DSM program, use Pacific Northwest spot capacity purchases and exchange arrangements, and add resources pursuant to directions by the CPUC. In particular, by 2003 SCE projects purchasing 400 MW of Pacific Northwest spot capacity and arranging up to 200 MW in Pacific Northwest seasonal exchanges.

San Diego Gas and Electric (SDG&E) is unable to meet its target reserve margin of 15 percent in 1993, falling approximately 270 MW short. By 2003 the deficit will increase to 1,600 MW. To avoid unnecessary regulatory delay, the CPUC has directed SDG&E to pursue the repowering of 455 MW, which should be in place by 1997. Other resource additions by the year 2003 include 420 MW in DSM savings; 100 MW in PNW "spot capacity" purchases; and 473 MW of QFs.

Los Angeles Department of Water and Power (LADWP) has sufficient resources to meet its requirements throughout the 20-year planning period. LADWP's projected capacity requirement in 2003 is 7,940 MW. Currently, LADWP depends on fossil fuel for two thirds of its generating capacity, with some hydro and nuclear. Recognizing the diversity of electricity resources is an important strategic element in its resource planning effort, LADWP is participating in a 10 MW solar project and is constructing its first geothermal power plant, which is expected to be operational by 1995. LADWP also will depend on DSM resources and repowering of existing units a under SCAQMD requirements.

Burbank, Glendale, and Pasadena (BGP) dispatch their systems separately from LADWP, although they have a pool arrangement with LADWP for imports. BGP resources must meet SCAQMD emission constraints as do those of and SCE. By 2003 the combined capacity requirement for the three cities is expected to reach 1,016 MW. The largest sources of existing firm capacity for BGP are natural gas units and purchased power. BGP is joint owner of a nuclear facility (30 MW) and a coal plant (138 MW in 1992).

Sacramento Municipal Utility District (SMUD) forecasts its capacity requirement by 2003 to be 3,257 MW. By 2003 SMUD will add 607 MW of gas-fired capacity, 120 MW from an out-of-state cogenerating facility, and an energy-only wind project. SMUD also will need capacity resources to meet its load by 2003. SMUD will depend on short-term purchases from the Pacific Northwest to delay building a new power plant until anticipated load growth appears more certain. SMUD shares in ownership of the California-Oregon Transmission Project (COTP).

Northern California Power Agency (NCPA) is comprised of 14 members from Northern and Central California, ten interconnected. Each member owns, operates and maintains an electric distribution system to serve the customers within its own service area. By 2003 NCPA capacity requirement is expected to reach 837 MW. The largest source of firm capacity from NCPA in 1996 is purchased power at 46 percent. NCPA is negotiating long-term contracts with California and Pacific Northwest parties, utilizing its transmission shares of the COTP.

In the Inland Southwest, 1989 load was approximately 9,884 MW. Since total generating capacity is far greater than load in this region, this part of the Southwest is expected to be surplus over the next 20 years.

Table G-9 CALIFORNIA - OREGON TRANSMISSION PROJECT Allocations to California Utilities and Use for Assumed Contracts (MW)

	COTP Share	Pending and Generic Contract Allocation_1/
TANC MEMBERS	1237.0	618.5
Alameda	16.5	8.2
Healdsburg	3.3	1.7
Lodi	23.4	11.7
Lompoc	2.3	1.1
Modesto	261.3	130.6
Palo Alto	49.5	24.7
Plumas	2.0	1.0
Redding	102.4	51.2
Roseville	28.4	14.2
SMUD	335.6	167.8
Santa Clara	256.1	128.0
Turlock	153.7	76.8
Ukiah	2.6	1.3
FEDERAL ALLOTTEES	65.0	32.5
S. San Joaquin	33.0	16.5
Trinity	4.0	2.0
Shasta	25.0	12.5
San Juan	2.0	1.0
Carmichael	1.0	0.5
WAPA	177.0	88.5
VERNON	121.0	60.5
TOTAL COTP	1600.0	800.0

_1/ Utilities are assumed to use up to half of their COTP entitlements for pending and generic contracts. Additional generic contracts may be added only if the COTP would not become the single largest contingency for reliability planning.

California Utilities' Assumed Air Quality Provisions

Southern California Edison

The South Coast AQMD Rule 1135 establishes the BARCT NOx requirements for existing utility boilers or their replacements. The rule applies to five utilities: Edison, LADWP, the cities of Burbank, Glendale, and Pasadena. Rule 1135 establishes the maximum daily average NOx rates (i.e., 0.15 lbs. per MWh for Edison), and daily and annual emissions caps for each of the five utilities. Rule 1135 required the affected utilities to submit compliance plans by January 1, 1992.

Ventura County APCD's adopted Rule 59 regulates NOx emissions from electricity generating facilities. Rule 59 will affect four electricity generating units in Ventura County, all operated by Edison.

The effect of Rule 1135 on Edison's system is included in ER 92 by assuming a system average NOx emission rate consistent with each of the specifications of the rule. The Commission assumes any new power plant (or replacement or repowered power plant) identified in Rule 1135 compliance plans to be uncommitted.

San Diego Gas and Electric Assumptions

The San Diego County APCD is proposing Rule 69 to reduce NOx emissions from existing utility boilers within the district. SDG&E is the only utility affected by the proposed rule. The provisions of this rule will apply to Encina Units 1 through 5 and South Bay Units 1 through 4. Rule 69 has different provisions and schedule requirements based on the heat rate of individual boilers.

As a simplifying assumption, ER 92 assumed for SDG&E system a NOx emission rate of 0.2 lbs. per MWh will be applied to all the boilers in the San Diego County APCD subject to Rule 69. It was also assumed that all boilers meet this emission factor by 1996.

Pacific Gas and Electric Assumptions

The Bay Area AQMD, Monterey Bay Unified APCD, and San Luis Obispo County APCD are currently considering BARCT rules to control NOx from utility boilers in their jurisdiction. Twenty-nine out of thirty-three of PG&E's steam boilers are situated in these three districts.

The Bay Area AQMD is proposing a NOx emission factor of 0.25 lbs. per MWh for all 18 PG&E boilers in the district. To achieve this standard, it was assumed 90 percent NOx reduction will be obtained on Contra Costa 6 and 7, Pittsburg 5, 6, and 7, and Potrero 3 by 1997.

PG&E owns and operates Moss Landing 1 through 7 in the Monterey Bay Unified APCD. The 1991 Air Quality Management Plan for the Monterey Bay Region recommends a NOx limit at this facility of no more than 0.15 lbs. per MWh. In order to achieve this goal for the collective facility, it was assumed that 90 percent NOx reduction will be applied to Moss Landing 6 and 7 by 1997. Based upon information contained in PG&E ER 92 supply forms and its 1993 General Rate Case, the following boilers are assumed to be in long-term reserve status: Moss Landing 1 (remain on long term reserve), Moss Landing 2 and 3 in 1995 and Moss Landing 4 and 5 in 2000. There are four large boilers at the PG&E Morro Bay Power Plant. The NOx limit recommended in the San Luis Obispo County APCD clean air plan is 0.20 lbs. per MWh. In order to achieve this goal, it was assumed that 90 percent NOx reduction will be applied to Morro Bay 1,2,3 and 4 by 1997.

Figure (Page G16 Figure G-1 ARea DESIGNATION FOR CALIFORNIA AMBIENT AIR QUALITY STANDARD OZONE)

Figure (Page G17 Figure G-2 ARea DESIGNATION FOR CALIFORNIA AMBIENT AIR QUALITY STANDARD ...)

Table G-10 Ambient Air Quality Standards

Pollutant	Averaging Time	National Standard	California Standard
Ozone (O_3)	1 Hour	0.12 ppm (235 ug/m^3)	0.09 ppm (180 ug/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
	1 Hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)

Nitrogen Dioxide (NO2)	Annual Average	0.053 ppm (100 ug/m^3)	---
	1 Hour	---	0.25 ppm (470 ug/m^3)
Sulfur Dioxide (SO2)	Annual Average	80 ug/m^3 (0.03 ppm)	---
	24 Hour	365 ug/m^3 (0.14 ppm)	0.04 ppm (105 ug/m^3)
	3 Hour	1300 ug/m^3 (0.5 ppm)	---
	1 Hour	---	0.25 ppm (655 ug/m^3)
Suspended Particulate Matter (PM10)	Annual Geometric Mean	---	30 ug/m^3
	24 Hour	150 ug/m^3	50 ug/m^3
	Annual Arithmetic Mean	50 ug/m^3	---
Sulfates (SO4)	24 Hour	---	25 ug/m^3
Hydrogen Sulfide (H2S)	1 Hour	---	0.03 ppm (42 ug/m^3)
amount to produce an coefficient of 0.23 per Visibility Reducing particulates when the Particulates is less than 70%.	1 Observation	---	In sufficient extinction kilometer due to relative humidity

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Appendix G. Part 3. PNW Fish

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APPENDIX G

Part 3. Pacific Northwest Fish

3.1 PNW Anadromous Fish

The Pacific Northwest supports a large number of anadromous fish (species that migrate downriver to the ocean to mature, then return upstream to spawn). The principal anadromous fish runs in the Columbia Basin are chinook coho, and sockeye salmon, and steelhead trout. Other Northwest river systems contain runs that include spring and fall chinook, coho, chum, pink salmon, and steelhead trout. As with some Columbia River anadromous fish stocks, many coastal and Puget Sound populations are severely depleted, largely due to habitat degradation or excessive harvest. These fish are an important resource to the Pacific Northwest, both for their economic value to the sport and commercial fisheries, and for their cultural and religious value to the region's Indian Tribes and others.

The development of dam and reservoir projects on the Columbia and Snake River and tributaries has reshaped the natural flows of the river. The use of storage reservoirs to capture runoff for later release results in reduced flows during the spring and early summer, when juvenile salmon and steelhead are migrating downstream to the ocean. Water velocities have also been reduced as a result of the increased cross-sectional area of the river due to run-of-river projects. These changes have slowed juvenile fish migration, exposing juvenile salmon and steelhead to predation and disease and impairing their ability to adapt to Salt water when they reach the ocean. Additional mortality occurs as fish attempt to pass each dam on their downstream migration to the ocean.

BPA, the U.S. Army Corp of Engineers, and the U.S. Bureau of Reclamation are jointly conducting a public review of the multi-purpose operation of Federal hydro facilities in the

Columbia River basin. A Final Environmental Impact Statement (eis) is planned for 1994.

The System Operation Review will determine the operating requirements necessary to serve the multiple purposes of the Federal facilities, including power generation, fisheries, recreation, irrigation, navigation, and flood control. The resulting decisions on operating requirements will apply to power operations for Intertie transactions and all other BPA power transactions. The proposals studied in this Non-Federal Participation (NFP) eis do not prejudice SOR matters. BPA's power obligations will be served with a mix of resources in context of the operating constraints applicable to each resource.

Endangered Species Act processes have been created to make decisions regarding the operation of hydro plants and affected anadromous fish. The National Marine Fisheries Service (NMFS) is currently acting on petitions to protect certain anadromous fish species

in the Columbia and Snake River systems. Operating requirements for Federal hydroelectric facilities within these river systems will be subject to decisions made under these processes. The proposals studied in the NFP eis do not prejudice ESA recovery plan matters. The NFP eis analysis uses the best available information regarding operations relevant to fisheries and other uses.

3.2 Resident Fish of the Pacific Northwest

Resident fish are freshwater fish that live and migrate within the rivers, streams, and lakes of Washington, Oregon, Idaho, and western Montana. A few species that were originally anadromous but are now landlocked are included with the "resident" fishes. A number of Federal reservoirs support substantial resident fish populations. Reservoirs whose resident fish would be most affected by changes in hydro operations are Hungry Horse and Lake Koocanusa (behind Libby Dam) in northern Montana, Grand Coulee in central Washington, and Dworshak in Idaho. Common game fish species in Hungry Horse include westslope cutthroat trout, Dolly Varden, and mountain whitefish.

Common game fish species in Libby Reservoir include western cutthroat trout, rainbow trout, Dolly Varden, and kokanee salmon. Grand Coulee supports an economically valuable recreational fishery for walleye and rainbow trout. Sport fish caught in Dworshak include kokanee salmon, rainbow trout, and smallmouth bass.

The Kootenai River below Libby Dam and the Flathead River below Hungry Horse Dam support important populations of resident game fish. These include kokanee in the Flathead River system, and westslope cutthroat trout, rainbow trout, and Dolly Varden in the Kootenai River. The kokanee that spawn in the Flathead River system below Hungry Horse migrate upstream from Flathead Lake. currently, this population of kokanee is in decline. Montana Department of Fish, Wildlife, and Parks (MDFWP) is developing a mitigation plan for the Flathead system that may or may not include rebuilding the kokanee population.

Some of the resident fish of the Pacific Northwest are threatened, endangered, or of special concern to the management agencies charged with protecting these species.

3.3 Protected Areas

The Northwest Power Act directs the Council to develop a "program to protect, mitigate, and enhance fish and wildlife, including related spawning grounds and habitat on the Columbia River and its tributaries." Large habitat losses have occurred in the Columbia River Basin as a result of hydroelectric and other development. The Council has estimated that 4,600 stream miles of salmon and steelhead habitat have been lost (a 30 percent decline), not including losses of resident fish and wildlife habitat. Significant habitat losses have also occurred in other areas in the region, and these losses have

played an important role in declines of regional fish and wildlife populations. The Council is required to consider fish, wildlife, their habitat, and other environmental factors in developing its regional power plan.

Past mitigation efforts have not been able to compensate fully for the effects of hydropower and other development. The loss of anadromous fish habitat beyond the Hells Canyon complex on the Snake

River is a significant example. In addition, recent listings by the NMFS of several stocks of anadromous fish as threatened or endangered underscore the need to protect remaining habitat. Disagreements among and between the public; fishery biologists; Federal, state, and local agencies; and Indian tribes over the possible effects of development, and the likelihood that mitigation may be successful, have been common. These disagreements add to developer costs and utility rates, and leave the region less certain about its ability to develop new resources quickly when needed.

To protect the critical fish and wildlife habitat that remains, to avoid expensive and divisive disputes over hydropower development in sensitive fish and wildlife areas in the region, and to reduce costs and uncertainties in the region's ability to meet is power needs, the Council embarked on a process 10 years ago to study areas where development would have substantial and irreversible adverse effects. In 1987, the Council adopted the goal of doubling salmon and steelhead runs within the Columbia River Basin. As part of the strategy for meeting the doubling goal while protecting valuable fish habitat from damage caused by hydropower development (thus preserving an environment for wild and naturally spawning fish), the Council, on August 10, 1988, approved Protected Areas amendments to the Fish and Wildlife Program and Power Plan. In brief, the final rule adopted a single standard of protection for all Protected Areas: because Protected Areas represent the region's most valuable fish and wildlife habitat, hydropower development should not be allowed in Protected Areas, but should be focused in other river reaches. The final rule does not apply to projects existing or licensed as of August 10, 1988. In addition, the rule provides for developers to seek an exemption from the Council for a project that would have "exceptional fish and wildlife benefits."

The Council's Power Plan identifies the amount of new hydropower the region can count on to be developed in the next 20 years. Because projects proposed in Protected Areas are less likely to be built, the region's "supply curves" do not count on new hydro being developed in them.

During the Council's rulemaking, staff examined the impacts of designating Protected Areas on projects for which a preliminary permit, license, or exemption was active at the Federal Energy

Regulatory Commission (FERC). That analysis showed that out of 387 active projects, 241 (62 percent) would be affected by a Protected Area designation. Of the 241 affected projects, 123 were located within the Columbia River Basin and 118 were located outside the Basin. Total potential foregone was 1,530 MW of capacity and 814 aMW of energy. On the other hand,

146 projects (38 percent) Were unaffected by Protected Area designation, representing 1,780 MW of capacity and 917 aMW of energy. The mileage now protected represents less than 15 percent (70,796 km or 44,000 miles) of the Northwest's rivers and streams.

The primary purpose of Protected Areas is to direct developers to the least environmentally sensitive sites. Protected Areas designations can be modified depending on future energy needs and other potential new supplies.

The region's current hydropower supply curves, developed jointly by BPA, the Council, and the States in 1989, show an "upper bound" of regional potential at 910 aMW of new hydro available outside of Protected Areas at a cost of less than 6.0(cents)kWh (levelized in 1988 dollars), with the amount of "likely developable" hydro outside of Protected Areas at 410 aMW. From 1988 through 1990, 237 MW (or about 100 aMW) of new hydro capacity was installed in the region outside of Protected Areas, well on the way to meeting projections of available supply.

On May 17,1988, BPA adopted its Long-Term Intertie Access Policy (LTIAP) governing provisions for use of BPA's Intertie with California. Protected Areas within the Columbia River Basin were adopted as the fish and wildlife protection mechanism in the LTIAP. The policy provides for decreasing utilities' access to the Intertie if they develop or acquire the output from a new hydro project located in a Protected area within the Columbia Basin.

Since August 1988, FERC has not issued a license or exemption that conflicts with the Protected Areas amendments. As of January 1991, FERC has had few new applications for licenses in Protected Areas, although FERC has granted preliminary permits on sites located within Protected Areas.

As explained in Section 1.3.11, BPA is currently developing a protected areas policy to apply to BPA's future actions, including Non-Federal Participation transactions. The policy would provide for no transmission of energy over the Intertie from a new hydro project sited in an area with the Columbia River Basin designated as protected in the Council's Protected Areas Program.

Appendix G. Part 4. PNW Cultural Resources

APPENDIX G.

Part 4. PNW Cultural Resources

Cultural resources are the irreplaceable evidence of human occupation or activity as reflected in any district, site, building, structure, artifact, ruin, object, work of art, architecture, or natural feature that was important in human history at the national, state, or local level. Cultural resources that could be affected by BPA actions are located throughout the study area. Historic properties or districts that undergo conservation remodels or retrofits could be affected.

BPA actions that affect the operation of the existing PNW power system can also affect cultural resources. Changes in hydro system operations can cause changes in reservoir levels at the five Federal storage reservoirs on the Columbia and Snake Rivers: Grand Coulee (Lake Roosevelt), Libby (Lake Koocanusa), Albeni Falls (Lake Pend Oreille), Hungry Horse, and Dworshak. Numerous archeological and historic sites, especially Indian burials and ancient habitations, are known to exist within the reservoir areas and many sites remain to be discovered. BPA has a programmatic agreement with several responsible agencies that provides for consultation and mitigation on this issue (see Chapter 5).

Further description of PNW historical development and cultural heritage is contained in BPA's Resource Programs eis, Appendix A, Section 1.

Appendix G. Part 5. Study Area Social and Economic Environment

APPENDIX G

Part 5. Study Area Social and Economic Considerations

5.1. Geography and Land Use

Pacific Northwest

The geography and land uses of the affected environment in the Pacific Northwest center on the Columbia-Snake River system. The Columbia River Basin contains more than 668,220 square kilometers (km) (258,000 square miles (mi)) of drainage, including most of Washington, Oregon, and Idaho; Montana west of the Rocky Mountains; small areas of Wyoming, Utah, and Nevada; and southeastern British Columbia. The Pacific Northwest includes all or portions of three physiographic provinces: Northern Rocky Mountain, Columbia Plateau, and Pacific Mountain system. Major features include the Columbia and Snake Rivers, the Puget Sound and Willamette Valley plains, and the Coast Range, Cascade, and Rocky Mountains. These features define the climate, vegetation, transportation, and development patterns of the region.

Half the region is covered by forest (primarily Douglas fir or varieties of pine), most densely west of the Cascade Range. Rangeland occupies substantial areas in the Snake River and Rocky Mountain regions. Agricultural lands are located primarily on the Columbia River Plateau, along the Snake River, and in the Willamette Valley. About two-thirds of the land in the region is publicly owned, enabling the development of multiple use land programs and extensive recreational opportunities. Land managers include the Federal Government (including the U.S. Forest Service, Bureau of Land Management, Department of Energy, and Department of Defense), State and local governments, and Indian tribes. The rest of the land is privately owned.

The Cascade Range, which runs north-south, divides Oregon and Washington into two climatic regions. Coastal climate is mild and wet, with only occasional extremes of temperature. East of the Cascades, most of the precipitation is in the form of snow, and summer months are hot and dry.

Elevations of the Pacific Northwest range from sea level to 4392 meters (m) (14,410 feet (ft)) at Mt. Rainier in Washington. Idaho experiences a wide variation in climate. Pacific Ocean air brings temperate climate to the northern third of the state, while high mountains on the eastern border tend to block cold air from Montana and Wyoming.

Beginning in southeastern British Columbia, the Columbia River flows south and west for 1953 km (1,214 mi) to the Pacific Ocean. From the point it passes into the State of Washington to its mouth, it drops steadily for 1204 km (7411 mi). The Snake River, which is 1670 km (1,038 mi) long, begins in northwestern Wyoming. It flows west and north, forming part of the borders between Oregon and

Idaho and between Idaho and Washington. Part of that border is the nation's deepest canyon (Hell's Canyon). In southern Washington, the Snake River joins the Columbia, which flows west and north, forming the border between Oregon and Washington. The Snake and Columbia flow through extensive wilderness, scenic, and recreation areas. The rivers pass through irrigated agricultural area in the plateaus east of the Cascade Mountains and through the Cascade and Coast Mountain Ranges on the way to the Pacific Ocean.

California and the Inland Southwest

Most of California is part of the Pacific Mountain System physiographic region, although portions of southeastern California are part of the Basin and Range province.

The Southern Cascade Mountains and the Sierra Nevada form California's backbone, a barrier the length of the state. Elevations reach over 4267 m (14,000 ft) above sea level at Mt. Whitney and Mt. Shasta. The majority of the mountain ranges trend north-south and exert major influences on the climate of the region, with extremes in several areas. To the west of this barrier lies the Great Valley and the California Coast Ranges. The valley contains the major population centers and is a high-value agricultural area, heavily irrigated. The Coast Ranges, mostly lower than 1524 m (5,000 ft), support commercial forestry, grazing, and specialty crops such as wine grapes.

To the east of the Cascades and Sierra barrier are the parts of California in the Basin and Range province. It is a semi-desert to desert region of plateaus, basins, plains, and isolated mountain ranges.

The Inland Southwest includes some of the driest portions of the United States. Physiographically, the region is in the Basin and Range, the Colorado Plateau, and portions of the southern Rocky Mountains provinces. Topographically, the region encompasses the lowest and some of the highest elevations in the continental United States. The Colorado River Basin is the major drainage for the region, rising on the Continental Divide and ending at the Pacific Ocean. It contains major multipurpose dams, such as Hoover Dam, which provide electric power, water supplies, and recreation areas. The land is fairly arid, except for the Rocky Mountains, which are moderately wet. The area tends to be water-limited, with most precipitation occurring in the mountains. Land use includes mining and mineral processing, cattle ranching, and farming. Since much of the land is and, agriculture is dependent upon irrigation, although dry farming is practiced in portions of New Mexico.

British Columbia

The geography and land uses of British Columbia, like the Pacific Northwest, center on river systems. Columbia Lake, the source of the Columbia River, is situated 812 m (2,664 ft) above sea level in the Canadian Rocky Mountains in southeastern British Columbia. The river flows north, then turns sharply

to flow south to the international border, for a total of 739 km (459 mi) and a drainage area of 102 435 square kilometers (39,550 square miles) in Canada. Near the border, the Columbia is pained by the Kootenay River. The Kootenay begins in the Canadian Rockies, proceeds south into Montana and Idaho (where it is the Kootenai), then returns north into Canada before joining the Columbia. The

Peace River, which also begins in the Canadian Rocky Mountains in eastern British Columbia, flows north and east into Alberta, eventually emptying into the Arctic Ocean. Regulation of these river systems by dams has reduced seasonal flow variations and, on the Columbia, reduced the occurrence and severity of floods. Dams also produce power.

Land uses in British Columbia include forestry, mining, mineral processing, cattle ranching, and tourism. Since much of the terrain is mountainous, there is little arable land. The forest industry dominates the western portion; the eastern reaches include a broader mix of uses, such as agriculture, forestry, mining, oil and gas, and transportation. British Columbia's waters produce a rich harvest of fish, including salmon. Water resource uses also include recreation, transportation, and power production.

5.2 Population

Pacific Northwest

In the Pacific Northwest, population centers around Seattle/Tacoma (WA), Portland/Vancouver (OR/WA), Eugene/Springfield (OR), Spokane (WA), and Boise/Nampa/Caldwell (ID). Estimates indicate that the population in Washington grew from about 4.13 million in 1980 to about 4.80 million in 1990, a 16 percent net increase and an annual rate of growth of 1.51 percent. The population of Oregon increased from about 2.63 million In 1980 to an estimated 2.84 million in 1990, an 8.1 percent net increase and an annual growth rate of 0.8 percent. The population in Idaho grew from 947,000 to about 1 million, a 6.6 percent net increase and an annual growth of 0.6 percent.

California and the Inland Southwest

In California, population is centered around Los Angeles, San Diego, San Francisco, San Jose, and Sacramento. The much smaller population of the Inland Southwest is clustered in the Salt Lake City, Phoenix, Tuscon, Albuquerque, Santa Fe, Las Vegas, and Reno metropolitan areas. The population of the region as a whole is 36,264,000, with 29,473,000 in California (California State Department of Finance, Demographic Research Unit).

British Columbia

Population in British Columbia is centered around Vancouver, Victoria, and a few smaller centers. The population of the province has grown from approximately 2.5 million in 1976 to about 3 million in

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1990 (Canadian Consulate General, Office of Tourism). British Columbia Hydro and Power Authority (BC Hydro) has projected a population growth of about 1.6 percent on an annual basis through 1999 and 1.3 percent per year for the following 10 years.

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5.3 Industry/Economic Base

Pacific Northwest

Over the past 10 years, the economy of the Pacific Northwest has evolved from being resource-based to being more diverse, with growing trade and service sectors. In 1980, resource-based industries accounted for 30.9 percent of manufacturing employment; by 1990, their share had fallen to 27.2 percent. High technology industries (aerospace, electronics, and scientific instruments), have grown in share over the last decade from 30.3 to 42.0 percent of total manufacturing. Overall, the manufacturing share of the regional economy was 19.4 percent in 1980 and fell to 17.7 percent by 1990.

The lumber and wood products industry still plays an important role in the region's economy, with 3.4 percent of the total regional employment, but this sector has declined from a decade ago, when it accounted for 4.4 percent of total employment. Food processing has fallen from 2.5 percent of total employment in 1980 to 2.1 percent in 1990. This loss of employment share has been due to an increase in the relative size of the employment base and productivity gains brought on by plant upgrades and other efficiencies. Transportation equipment, primarily Boeing, has remained at nearly 4 percent of total employment over the last decade, and the electronics and scientific instruments industries have grown from 13.4 percent of total employment to 17.7 percent. Energy-intensive aluminum production is economically important to the region, but the level of employment in this sector is relatively small (0.7 percent of total employment in 1990).

The nonmanufacturing share of total employment rose during the 1980s from 80.6 to 82.3 percent. An increase in wholesale and retail trade and services accounts for most of the gain. Employment in trade grew from 24.1 percent of total employment in 1980 to 25.0 percent in 1990. The services sector grew from 18.8 percent of total employment in 1980 to 22.9 percent in 1990. The region's growing trade with California and the Far East also broadens the economic base. Twenty-five percent of U.S. exports to Asia and 30 percent of all U.S. exported goods are shipped through Pacific Northwest ports. In fact, the Ports of Seattle and Tacoma are the fourth and sixth largest ports in the world.

The advantage of low-cost energy relative to other areas has strengthened the region's economic base. Due to the availability of natural gas from Canada and the region's hydro base for electricity, the Pacific Northwest has a long-term energy advantage. On average recently, the region's electricity prices ran 40 percent lower than the national average and natural gas prices were 16 percent less. The region still can be hard-hit by high interest rates and their dampening effect on housing, which is the biggest source of demand for the region's lumber and wood products. However, more diversity

and efficiency in industries in the region means more resistance to severe fluctuations now than in the past. Continued high levels of international trade should help offset the negative impact of periodic national business cycles, and the nonmanufacturing service sector of the region's economy is expected to continue to grow faster than total employment.

California, with over 29 million people (more than 10 percent of the nation's total population) represents an important market for the Pacific Northwest. The tourism industry, fueled by the region's superlative scenic beauty and interesting history, stimulates the economies of less populated regions as well as the service and trade sectors. Agriculture also is a substantial industry in the region, employing about 275,000 in 1990, down from about 285,000 in 1980. The decline in agriculture employment is part of the shift toward a less resource-dependent economy, and also is due to growing productivity in the farm sector.

California and the Inland Southwest

California has a rich endowment of natural resources, amenities, and climate. The state is a major source of the nation's fruits and vegetables. Its agricultural sector ranks first in the nation in cash value and produces virtually every crop grown in temperate zones. Lumber production is second only to Oregon, and its mining production ranks among the top three states. Employment in manufacturing industries is the leading source of personal income, followed by government, wholesale and retail trade, and service occupations. The entertainment industry, although it has declined somewhat since World War II, is still a significant part of the state's economy, and tourism is one of the fastest growing sectors. The economy of the Inland Southwest is based on mining and ore processing, manufacturing, services, agriculture, and tourism.

British Columbia

The economy of British Columbia as a whole, and especially the areas through which-the Columbia and Peace Rivers flow, is heavily resource based. Forestry, mining, and mineral processing industries are important sources of income and employment. In many cases, these industries rely on the river system either for power or transportation or both. The river systems also are closely tied to another important economic base--tourism and recreation (Envirocon 1986). Petroleum and natural gas production also are important to the economy. There is abundant hydroelectricity, natural gas, and coal to serve the needs of both domestic and export customers (B.C. Ministry of Energy, Mines, and Petroleum Resources). However, high unemployment (currently 8.3 percent, seasonally adjusted) has resulted from economic dependence on natural resources (Labor Force Annual Averages, 1990, 71-220)). Nonetheless, with an ample and diverse energy supply, a carefully developed infrastructure, and easy access to world markets, British Columbia is poised for future development.

Appendix G. Part 6 Western States Vegetation and Wildlife Information

2.23 Vegetation

The northwest United States is among the more diverse regions of North America. This region includes wet coastal and dry interior mountain ranges, miles of coastline, interior valley, basins, and high desert plateaus. Moisture, temperature, and substrate vary greatly, as does the vegetation.

In the Pacific Mountain System, Douglas fir forests dominate the native vegetation from the coast to about 5,000 feet of the moist western slopes of the cascades. The drier east side of the Cascades supports yellow pine/lodgepole pine forests.

The forests of the western Cascade Mountains comprise the most densely forested region in the United States. These forests represent the maximal development of temperate coniferous forests in the world in terms of extent and size. The climax forests of this area are almost totally dominated by coniferous species. Generally, conifers are pioneer species--species that first populate an area, but which give way after many years to hardwood or mixed forest. However, in much of this region, this pattern is reversed, with hardwood trees such as red alder or bigleaf maple west of the Cascades playing an initial role in the vegetative succession. A second feature of this forest is the size and longevity of the dominant species. The climax forests found by the pioneers were comprised of trees several feet through at the base, several hundred feet tall, and several centuries old. Much of this forest is now second growth--forests that have grown up where virgin forests once stood. Forestry, clearing for agriculture and other development, and wildfires have removed much of the original forest.

Prairies are an important feature of the landscape south of Washington's Puget Sound. The occurrence of prairie indicates the area has been free of forest for many years. The origin and continued occurrence of the prairies stems from soil type and frequent burning. The soil is gravelly, derived from glacial outwash material coupled with low summer precipitation. The frequent burning resulted from natural causes, native human populations, and the early European settlers. Since settlement, the extent of these prairies has been rapidly diminishing as a result of invasion by Douglas fir trees and other native plants. The reforestation of these areas is probably due to fire protection and changing management of the land.

The Columbia Plateau physiographic region covers much of Washington and Oregon east of the Cascades and most of southern Idaho. The area is arid

to semi-arid, with low precipitation, warm to hot summers, and cold winters. The region is dominated by shrubs and grasses, such as bunchgrass and sagebrush communities. Juniper is an invading species. Forest vegetation is generally confined to areas with sufficient precipitation, and in the higher elevations. Much of this area has been changed by wildfire and grazing. The two dominant native shrubs are sagebrush and rabbit brush. Both are fire-sensitive and can be eliminated from an area for decades by fire. The major perennial grasses are bunch grass and fescue. Neither is adapted to heavy grazing. Two alien species that are well adapted to the steppe region and were able to invade areas that were burned or heavily grazed are cheatgrass and poa.

In the largely semi-arid climate of the Northern Rocky Mountains province (western Montana, northern Idaho, and northeastern Washington), native vegetation consists of larch/white pine or yellow pine/Douglas fir forests. Since European settlement, valleys such as the Flathead Valley in northwest Montana, are irrigated and farmed.

The lands surrounding the headwaters of the Columbia and Peace Rivers in British Columbia are heavily forested. Douglas fir is prominent in the Canadian

Rocky Mountains, and the valley bottoms in most areas are characterized by stands of western hemlock. The upland, subalpine zone includes Englemann spruce and lodgepole pine.

2.2.4 Wildlife

The wildlife of the Pacific Northwest and Montana is diverse, including larger mammals such as bear, elk, and deer, and smaller animals such as butterflies, snails, and birds. Although all are important to the environment, some arouse special interests because of their economic and recreational value or because they are listed for protection by a state (see Appendix A) or the Federal Government.

The following discussion lists some of the important wildlife found in the Pacific Northwest and Montana.

Some of the more recreationally important wildlife of the Pacific Northwest include deer, elk, moose, pronghorn, sheep, goats, and wild pigs. Many of the these animals are important game species.

Many of the mammals of the Pacific Northwest are protected or are considered for protection because they have been over-harvested or their habitat has been lost to other uses. The protected list of mammals includes carnivores

such as the gray wolf and the grizzly bear. It also includes whales, Columbia white-tailed deer, pygmy rabbit, shrews, squirrels, gophers, chipmunks, a mouse, voles, and bats. Not all of these mammals would be potentially affected by power plant development.

Besides mammals, Pacific Northwest wildlife includes a diverse bird population. Recreationally important birds include pheasants, geese, ducks, quail, and grouse. Many species have protected status with a state or the Federal Government. Protected birds include pelicans, Aleutian Canada goose, peregrine falcon, sandhill crane, eagles, and the spotted owl.

Reptiles, amphibians, molluscs, and insects are also part of the diverse wildlife of the Pacific Northwest. Many are protected or are being monitored for protection. The protected list includes several turtles, butterflies, beetles, snails, salamanders, and snakes.

Wildlife in the Canadian portion of the study area includes large populations of elk and deer, as well as mountain goats in higher elevations. Predators include the timber wolf, black and grizzly bears, and cougars. The Peace River area supports raptors, including bald eagles, hawks, and falcons.

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3.3.3 WILDLIFE AND VEGETATION

3.3.3.1 Western United States

Vegetation within the Pacific Northwest, Inland Southwest, and California falls into five general community types--forests/woodlands, shrublands, grasslands, deserts, and riparian/wetland. (See Figure 3.9 for location of these types; Table 3.19 for plant community descriptions.) Each plant community has characteristic associated wildlife types. Because the diversity is so considerable. and because combinations of these communities may occur with an intermixed or "edge" effect, the following discussions will focus on plant communities and associated wildlife. Specific types will be mentioned only as typifying a group or where species are specially protected. More extensive lists of characteristic wildlife species are found in Table 3.20. (Information following is from Biosystems 1986.)

Table 3.19 AFFECTED ENVIRONMENTS. VEGETATION AND WILDLIFE DOMINANT PLANT COMMUNITIES

Provinces Affected (Map Code)	Upland	Riparian/Wetland
American Desert (3220) This province includes the Mojave, Colorado, and Sonoran Deserts. Vegetation is usually very sparse, with bare ground between individual plants. Cacti and thorny shrubs are conspicuous, but many thornless shrubs and herbs are also present.	Creosote bush (3221): on the Sonoran Desert plains, creosote bush is the most widely distributed plant, and covers extensive areas in nearly pure stands. On some parts of the plains, cholla and other cacti are also common, as well as bursage. shadscale, brittlebush.	Mesquite grows along washes and watercourses

	Saltbush occurs on alkaline flats, yucca is common on sandy or loamy soils. Low woodland or scrubland.	

Table 3.19 (continued)

Provinces Affected (Map Code)	Upland	Riparian/Wetland
California Chaparral (M2620) Montane vegetation consists of species with thick, hard, evergreen leaves. One climax, dominated by trees, is called sclerophyll forest; the other, called chaparral, is dominated by shrubs. Forest appears on north-facing slopes and wetter sites; chaparral on south-facing slopes and drier sites. The coastal plains and interior valley have shrub and grassland communities. Baccharis (coyote brush) is often the dominant north coastal shrub: sage dominates in south coastal areas.	Sclerophyll forest: Dominant trees include live oaks, tanoak, California laurel, Pacific madrone, golden chinquapin, Pacific bayberry. Chaparral shrubland: dominant shrubs include chamiso, manzanita, Christmasberry, scrub oak, mountain mahogany, ceanothus Interior and coastal grassland and/or shrubland. Southcoastal shrublands are often dominated by sage.	Riparian broadleaf forest Coastal salt brackish marsh dominated by cordgrass and pickleweed Estuaries (e.g., Elkhorn Slough)
California Grassland (2610) Historically supported bunchgrasses, probably dominated by needlegrass except near the coast; today is dominated by introduced annual grasses.	Annual grassland: dominant species include wild oats, brome, fescue, barley. Valley grassland	Freshwater and brackish marshes 1/ (e.g., Tule marshes bordering lower reaches of Sacramento - San

(historical) 1/

Joaquin Delta)

Vernal pool

communities 1/

Riparian woodland 1/

consists of cottonwood,

willow, and California

sycamore at low

elevations; white

alder, bigleaf maple,

western azalea and

California hazelnut

at medium elevations;

and willow at high

elevations

Colorado Plateau (P3130) Grama-galleta steppe and
Riparian cottonwoods 1/
Lowest zone is covered by arid juniper-pinyon
grasslands and many bare areas. Xeric woodland mosaic
shrubs often grow in open stands among
the grasses. Sagebrush is dominant over
extensive areas. At low elevations in
the south, several kinds of cacti and
yucca are common.
Woodland zone is most extensive and is
dominated by open stands of pinyon pines
and junipers.
Montane vegetation varies considerably
over different parts of the Province. In
the southern part, ponderosa pine is
dominant. Douglas fir may be associated
with ponderosa pine or grow in more
sheltered areas or at higher elevations.

Great Plains - Shortgrass Prairie (3110) Grama-needlegrass-
Riparian woodlands
Characterized by steppe (shortgrass wheatgrass (3111)
dominated by cottonwood,
prairie), a formation class of short Wheatgrass-needlegrass
willow, and ash; these
grasses usually bunched and sparsely (3112)
occur in discontinuous

distributed; scattered trees and shrubs
stands along perennial
occasionally appear
streams or rivers

Table 3.19 (continued)

Provinces Affected (Map Code)	Upland	Riparian/Wetland
Mountain Sagebrush (3130) Sagebrush dominates vegetation of lower elevations. Shrubs all tolerate alkali in varying degrees; this tolerance is essential to their survival on the poorly drained soils that are widespread in the region. In areas where salt concentration is very high, even these shrubs are unable to grow; here communities dominated by greasewood or saltgrass appear.	Sagebrush-wheatgrass (3131): in addition to sagebrush, shadscale, fourwing saltbush, rubber rabbitbrush, spiny hopsage, and horsebrush are dominant shrubs.	
Mexican Highlands Shrub Steppe (3140) (Chihauhuan Desert). Four life belts are distinct in this province. The lowest is the desert belt, which extends from the American Desert upward along the San Pedro wash for a number of miles, north of the Santa Catalina Mountains. The extensive arid grassland belt covers most of the high plains of the province. The submontane belt covers most of the hills and lower mountain slopes. Several species of oak dominate this belt, but some juniper also occur. A montane belt (generally dominated by pines, but also occasionally including oaks, Douglas fir, or white fir) appears on upper slopes of higher mountains.	Low desert woodland or scrubland: characteristic plants include saguaro, paloverde, ironwood, creosote bush, cat-claw acacia Semi desert grassland: short grasses such as grama are abundant, but taller grasses are also present, as well as mesquite, yucca, juniper, other shrubs, and cacti (particularly cholla) Submontane woodland: dominated by oak species, but also containing juniper Montane forest: dominated by pines; also containing oak and fir species	
Pacific Forest (M2410)	Redwood forest (M2412)	North coast salt and

Coastal coniferous forests; primarily
brackish marshes 1/
montane, but including areas from sea
(e.g.. Sacramento - San
level to over 1500 m (5,000 ft)
Joaquin Delta, Suisun
Marsh, San Francisco
Bay)

California mixed evergreen
forest (M2414)
Sitka spruce-cedar-
hemlock forest (M2411)
Cedar-hemlock-Douglas fir
forest (M2413)
Silver fir-Douglas fir
forest (M2415)

Palouse Grassland (3120)
Before cultivation, dominated by prairie grasses. Possibly much of the sagebrush dominance in this region results from grazing

Prairie grasses: although numerous species characteristic of other grassland regions are present, the major dominants are distinctive; they include bluebunch wheatgrass, fescue, and bluegrass

Sierran Forest (M2610)
Characterized by well-marked vegetation zones. Coniferous and shrub associations occur on lower slopes and foothills, from about 455 to 1220 m (1,500 to 4,000 ft). Conifer forests occur in the montane zone, from about 600 to 1800 m (2,000 to 6,000 ft). The subalpine zone, between 1980 and 2900 m (6,500 and 9,500 ft), contains hemlock, fir, and pine species. Alpine zone consists of treeless areas above timberline.

Coniferous and shrub associations (on low slope and foothills) include digger pine and blue oak (dominant on higher foothills) and chaparral (common on lower slopes). Buckbrush and manzanita predominate in chaparral; several oak species are also commonly associated.

Provinces Affected (Map Code) Upland
Riparian/Wetland

Montane conifer forests: dominant trees include Douglas fir, sugar pine, white fir, incense cedar. Dense chaparral may sometimes persist

	in this zone after fire. Subalpine conifer forests: dominant trees include mountain hemlock, California red fir, lodgepole pine, western white pine, and whitebark pine. Lodgepole pine appears to have climax characteristics near upper limits of the zone
Upper Gila Mountains Forest (M3120) Well-marked vegetational zones are striking. Their distribution is controlled by a combination of altitude, latitude, direction of prevailing winds, slope exposure. The foothill zone extends to 2100 m (7,000 ft), montane zone from about 2100 to 2400 m (7,000 to 8,000 ft), subalpine zone replaces montane forest at about 2400 m (8,000 ft) on north-facing slopes and a little higher on all slopes. At about 3400 m (11,000 ft), alpine belt appears,	Foothill mosaic: includes areas dominated by mixed grasses, chaparral brush, oak-juniper woodland and/or pinyon juniper woodland Montane coniferous forests: from about 2100 m (7,000 ft), ponderosa pine occur on north-facing slopes, while pinyon-juniper dominate on south-facing slopes Subalpine forests: from about 2400 m (8,000 ft). Douglas fir is dominant tree, aspen is also common; and limber pine grows on rockier and drier sites. At about 2700 m (9,000 ft), Engelmann spruce and corkbark fir replace Douglas fir, Limber and bristlecone pines still grow in rockier sites. Treeline occurs at about 3400 m (11,000 ft).
Willamette-Puget Forest (2410) Where not cultivated, supports dense coniferous forests. In interior valleys, the coniferous forest is less dense than along the coast and often contains deciduous trees. Some prairies support open stands of oak or are broken by groves of Douglas fir and other trees. Poorly drained sites with swamp or bog communities are abundant.	Coniferous forest: dominant trees include western redcedar Douglas fir. Mixed coniferous deciduous forest: dominant trees include conifers listed above plus big leaf maple, Oregon ash, black cottonwood
Wyoming Basin (A3140) Riparian willows, sedges	Wheatgrass-needlegrass-

Chief vegetation is sagebrush or shad- sagebrush (A3141)
and cottonwoods
scale, with a mixture of short grasses. Sagebrush-wheatgrass (A3142)
Moist alkaline flats support alkali-
tolerant greasewood. Higher elevations
may support juniper pine

1/ Communities that are ecologically unique and/or particularly sensitive to disturbance.

Figure (Page G42 FIGURE 3.9 LOCATIONS OF ECOSYSTEM REGIONS AND ENERGY FACILITIES)

TABLE 3.20 CHARACTERISTIC WILDLIFE SPECIES IN FOUR PLANT COMMUNITY TYPES FOUND IN THE AFFECTED ENVIRONMENT

Forest/Woodland		Shrubland	
Typical Mammals:	Typical Birds:	Typical Mammals:	Typical Birds:
Mule Deer	Blue Grouse	Mule Deer	Grouse
Black Bear	Common Flicker	Coyote	Flycatchers
Coyote	Hairy, Downy, and	Grey Fox	Swallows
Bobcat	Three-toed Woodpeckers	Mountain Lion	Scrub and Pinyon Jays
Red or Grey Fox	Great Horned and Pygmy Owls	Bobcat	Thrashers
Mountain Lion	Hammond's, Western, and	Striped Skunk	Black-billed Magpie
Raccoon	Olive-sided Flycatchers	True Rabbits	Wrens
Striped Skunk	Steller's Jay	Chipmunks	Northern Mockingbird
Long-tailed Weasel	Clark's Nutcracker	Ground Squirrels	Common Yellow Throat
Deer Mouse	Common Raven	Brush Mice	and Yellow-breasted
Golden Mantled	Black-capped and	Woodrates	Chat
Ground Squirrel	Mountain Chickadees	Ermine	Towhees
Porcupine	White- and Red-breasted		Sparrows
Beaver	Nuthatches		Oporornis Warblers
Shrews	Hermit and Swainson's		

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Moles                     Thrushes                      Pronghorn Antelope in
Intermountain
Bats                    Ruby- and Golden-crowned         Sagebrush and
Wyoming Basin
                          Kinglets                      California Pocket
Mouse in California
                        Solitary Vireo                    Chaparral
                        Yellow-rumped, Townsend's,      Chisel-toothed
Kangaroo Rat in
 In Northern Areas        Black-throated gray, and        Intermountain
Sagebrush
 Only:                    other Warblers                Sagebrush Vole in
Intermountain
 -----------------      Evening and Pine Grosbeaks        Sagebrush and
Wyoming Basin
Marten                  Cassin's Finch
Mink                    Pine Siskin
Mountain Beaver         Red Crossbill
Northern Flying         Dark-eyed Junco
  Squirrel              Fox Sparrow


                     Grassland                                          Desert
--------------------------------------------------   ------------------------
-----------------------
  Typical Mammals:        Typical Birds:                Typical Carnivores:
Typical Birds:
---------------------   --------------------------   ----------------------
----------------------
Mule Deer               Horned Lark                  Coyote
Gila Woodpecker
Coyote                  Shrikes                      Spotted Skunk
Elf Owl
Fox                     Western Meadowlark           Kit fox
Gambel's Quail
Bobcat                  Brewer's Blackbird             (endangered)
Cactus Wren
Badger                  Sparrows
LeConte's Thrasher
Kangaroo Rats                                          Typical Rodents:
Typical Birds:

(cont.)
Pocket Mice              Typical Raptors:            Kangaroo Rats
Roadrunner
Pocket Gophers          Red-tailed Hawk              White-tailed
Black-throated
Ground Squirrels        Rough-legged Hawk              Antelope Squirrel
Sparrow
Prairie Dogs             Swainson's Hawk              Botta's Pocket
Harvest Mice            Ferruninous Hawk               Gopher
Endangered

Reptiles:
White- and Black-       Northern Harrier             Pocket Mice
Gila Monster
```

tailed Jackrabbit Burrowing Owl Cactus, Northern
Desert Tortoise
American Kestrel and Southern
In the Great Plains: Prairie Falcon Grasshopper Mice
Pronghorn Antelope Desert Cotton-tail
Black-footed Ferret
(endangered)

3.3.3.1.1 Forest/Woodland and Wildlife

The forest/woodland plant community provides many "layers" of habitat for wildlife, from the ground into the upper branches of older trees. Most vulnerable to change are older stands of trees of various ages, which may take a century or more to develop and which thus cannot easily or quickly be replaced.

Large and small mammals, including deer, members of the weasel and skunk family, and rodents such as squirrels and porcupine, are found in the forested areas. Any of these mammals that prefers a narrowly defined habitat can be affected by disturbance or removal of habitat. The forest community, with its many varieties of trees, houses a large number and variety of birds, depending on the region and composition of the forest. (See Table 3.20 for a listing of species shared by many of the forested areas.)

3.3.3.1.2 Shrubland/ Wildlife

Shrublands are located in areas too harsh for forests and/or areas subject to repeated natural disturbances such as floods or fires. They may therefore be more resilient to human disturbances, but may also be replaced by grasslands species if they are disturbed. The major shrubland communities in the area (California Chaparral, Wyoming Basin, and Intermountain Sagebrush) are separated by mountain ranges, and so tend to contain widely differing wildlife communities. They do share adaptable wide-ranging species such as mule deer, coyote, gray fox, mountain lion, and a variety of birds. Each shrubland contains many small mammals and all contain the ermine, a common hunter of these mammals. Birds common to shrublands are listed in Table 3.20.

3.3.3.1.3 Grasslands/Wildlife

With its tremendous volume of seed-bearing but nonwoody materials, grasslands typically sustain fewer kinds of wildlife, but very large numbers of individual species such as rodents (e.g., ground squirrels). These small mammals attract predators, including hawks, The three predominantly grassland provinces (California Grassland, Palouse, and Great Plains--Shortgrass Prairie) are separated by mountain ranges. Only wide-ranging mammals such as mule deer, coyotes, and badgers occur in all three. Pronghorn antelope and the endangered black-footed ferret (Musteal nigripes) are also found in the Great Plains. Other animals and birds commonly found in grassland provinces are listed in Table 3.20. Grasslands habitat supports fewer birds where appropriate perching and nesting habitat is sparse.

3.3.3.1.4 Desert/Wildlife

Deserts are both harsh and fragile environments in which plant growth rates are slow. Revegetation may take years or decades. The wildlife inhabiting this environment is often very specialized for the harsh conditions, obtaining water from vegetation and avoiding daytime heat by being active primarily at night. Dominant carnivores are small and nocturnal. They include the coyote and spotted skunk, as well as the endangered kit fox (Vulpes macrotis) in some areas. Varieties of rodent (such as kangaroo rats and ground squirrels) are fairly common. Areas with cactus or brush may support a variety of birds, especially where water sources allow trees to grow. Deserts are also home to a number of endangered reptiles, including the gila monster (Heloderma suspectum) and the desert tortoise (Gopherus Agassazi).

3.3.3.1.5 Riparian/Wetland/Wildlife

Riparian/wetland plant communities have very high vegetation and wildlife value. This discussion on riparian vegetation is not classified according to habitat type because of the great diversity along the Columbia and Snake Rivers and their tributaries. These habitat types can range from sand dunes to various types of wetlands. Deer, beaver and other aquatic and terrestrial furbearers, small mammals, waterfowl, upland game birds, reptiles, and amphibians are among the common year-round users of riparian/wetland areas. Wintering elk and moose may also use these areas.

Before dams were built on the Columbia River and its tributaries, riparian vegetation zones developed through natural succession. Many plant species dependent on a high water table or periodic inundation were present. However, some areas subject to natural flooding eroded and poorly supported vegetation. The flooding of the river valleys as dams were built destroyed much of the original riparian vegetation. In some cases, new vegetation similar to previous types has replaced them, but higher on the shoreline to correspond with the new, higher waterline.

Changes or disturbances to water areas, wetlands, and the high-yield grain crops adjacent to wetlands, contribute to an increase or decrease in wildlife and waterfowl populations and habitat. These changes and disturbances are associated with shoreline construction, water level fluctuations, and shoreline erosion. Shoreline erosion in some areas has created unstable conditions in which vegetation cannot become established. Slides and wave action continuously remove soil and plant materials. Construction efforts to control water erosion have created miles of shoreline covered with rock riprap in which little will grow. Water level fluctuations also have prevented the riparian community from developing, except near the highest pool elevation.

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Appendix H. Public Involvement Activities

ACTIVITIES

DATE

Members of Congress and Northwest Utilities Express Interest in Participation 6/87

BPA's "March Study" on Participation Published 3/88

Decision to Construct, Operate ad Maintain the third AC Intertie as a Federal Project 9/27/88
Released in Administrator's Record of Decision

Participation Proposal and Notice of Intent to Prepare an eis Distributed for Public 12/22/88
Review ad Comment

Public Meeting Held on Participation Proposal in Portland 1/17/89

Close of Comment on Non-Federal Participation Proposal 2/10/89

Comment Summary and Letter Announcing Availability of Comments and Comment 4/13/89
Compendium Mailed to Interested Parties

Formal 7(i) Rate Process to Establish a Price for Participation Initiated 11/22/89

Formal 7(i) Rate Process Concluded 6/28/90

Draft eis Implementation Plan Distributed for Public Review and Comment 12/90

Close of Comment on Draft NFP eis Implementation Plan 2/1/91

Draft eis Implementation Plan submitted to DOE HQ for Approval 8/5/91

DOE HQ Approval of eis Implementation 8/26/91

Workplan related to AC Intertie Capacity Ownership mailed to Interested Parties 3/11/92

Proposed Alternative Methodologies for Allocating non-Federal Participation in the 6/8/92
Third AC Intertie Distributed for Public Comment BPA issued its June 5,1992,
allocation methodology paper, "Alternative Allocation Methodologies for Non-Federal
Participation in-the AC Intertie."

Comments being accepted on the Marketing and Transmission Proposal to be 8/17/92
addressed in the NFP eis

Comment Summary and Response to Comments received on Alternative Allocation 9/15/92
Methodologies for Non-Federal Participation in the AC Intertie mailed to MOUs

Comment Summary and Letter announcing Availability of comments on Allocation 9/25/92
Methodology paper mailed to Interested Parties

Clarification process ad Schedule issues related to AC Intertie Capacity Ownership 10/14/92
Distributed to MOU Signatories

H1

Proposed process for Allocations and Contract Negotiations distributed to MOU 1/22/93
signatories

Letter sent requesting comments on Section 9(c) Non-Federal Participation 4/2/93

Close of Comment on Section 9(c) Non-Federal Participation policy addressing 4/30/93
exports over the Non-Federal Participation shares of Intertie.

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Non-Federal Participation Final Environmental Impact Statement
Response to Comments on Draft eis

Commenter: Jerome Peterson, Chief of Operations, USBR, Grand Coulee Dam
Comment # 3ACP-10015

Response:
Correction made. Deis, page 2-17, Grand Coulee annual irrigation pumping is 27 million acre feet, not 1.3 million acre feet.

Commenter: Gregory H. Bowers
Comment # 3ACP-10-0016

Response:

1. The comment incorrectly suggests that any action must provide a net increase in revenues or it fails to meet the need since one of BPA's overall purposes is to enhance its revenues. First, BPA's stated need for action in the NFP eis is its need and that of other PNW entities for

interregional transfers with the PSW region using the Intertie. Second, BPA must select from reasonable alternatives that serve that need in the context of BPA's purposes, including: revenue enhancement via BPA access to a more diverse PSW market, providing fair Intertie access to other parties, supporting environmental quality, and benefiting overall economic and operational efficiency. Third, the comment also fails to take into account that the eis concerns two action areas: non-Federal participation and Federal marketing and joint ventures, which could be balanced to reasonably meet BPA's revenue purpose and other purposes.

2. This comment is mistaken in three areas:

* The Deis Need section included some background information on the objectives of the Third AC construction project that was intended to refresh the reader's understanding of this prior decision. This obviously confused the commenter. BPA's Need is in the first sentence referring to interregional transfers. For the Feis, this background material will be relocated under the descriptions of relationship to other actions.

* The comment implies that need for action is dependent on existence of a "large" PSW capacity surplus. It also claims without substantiation that the Deis data on PNW/PSW diversity is incorrect. As explained in supporting technical material in Chapter 2, PNW and PSW load/resource diversities are still substantial. Data on the surpluses in either region for diversity transactions were taken from the most current available official sources, including the California Energy Commission's (CEC) last Electricity Report (ER-92), BPA's 1992 PNW Loads and Resources Study, and BPA's 1992 Resource Program. The Deis explains in the Chapter 2 description of the affected environment and in the Chapter 4 analysis of impacts that the amount of useful diversity between the two regions has decreased somewhat, due partly to increased California independent producer generation with limited displaceability, air quality controls on resource generation in California, and new hydro operating limitations in the PNW. However, there still appear

to be mutual economic and environmental benefits to be gained by negotiated diversity transactions on the Intertie.

* The comment asserts that an action that can happen with or without the proposal is not a need addressed by the proposal. For NEPA purposes, it is acknowledged that there may be alternative means to meet the need. These alternatives may be more orless successful at meeting need and achieving the other purpose of the agency. It is true that there are other means to approach the NFP Deis need for interregional transfers. These other means are addressed by the alternatives, including the No Action alternative. The analysis in Chapter 4 candidly explained that the active spot market assumed in the No Action alternative did capture some of the benefits of long-term interregional transfers. However, documentation from the environmental exchange agreements of recent years show that the spot market can be improved upon by well-designed contracts such as those proposed under the Federal Marketing and Joint Ventures alternative.

3. The comment claims that energy exchanges are unrelated to the proposed actions, but this is at odds with the clear statements of BPA's two preferred alternatives, Capacity Ownership and Federal Marketing and Joint Ventures. The Deis discussion in Chapters 3 and 4 explained that the Capacity Ownership alternative would be highly likely to facilitate energy exchanges as indicated by the contracts pursued by the interested parties. The Marketing and Joint Ventures alternative would encourage energy exchanges, which would help optimize BPA's resources.

4. The comment entirely misrepresents a portion of the Deis by taking a phrase out of context to support a claim that the Deis attempts to deny the impact of transmission autonomy on west coast market influences. A reading of the whole paragraph from which the phrase is taken (pages S-3 & 4) shows that the Deis explicitly acknowledges that transmission access autonomy would probably increase firm transactions and resource development, but by an unquantifiable degree. The phrase quoted was part of a sentence indicating that autonomy would not be expected to change the relative desirability of seasonal exchanges versus firm power sales or other types of contracts. The factors that would affect a party's choice among those options would be linked to its loads, resources, financial condition, and other factors.

5. This comment asserts that the Deis estimate of maximum new resource development is in fact the expected effect. Environmental analysis would be simple if it were possible to analyze potential power marketing actions of 20 years in duration and emerge with a single point forecast of the impacts on any factor. In reality, as with all long-term projections involving significant uncertainties, the NFP Deis projections of impacts over time spread into a fan of more or less probable effects. The Deis characterized the greatest estimates of new resource development as "large" relative to current resource plans. The Deis also indicated that development to that level was not probable given current information on west coast overall need for resources, contract preferences of the parties, and economic forecasts.

6. Contrary to the comment, the Deis estimate carefully analyzed possible changes in PNW coal plant operation, as well as other large and small thermal resources. Summarizing briefly, the Deis explained that PNW coal plants generally have low variable costs, often making them economic for spot meet transactions, and Chapter 4 analysis found that this would not be greatly changed in either direction by the alternatives. Quantitative analysis in the Deis

showed that coal plant operation is far more significantly linked to weather conditions such as water supply than by Intertie contract scenarios.

7. This comment suggests, first, that the NFP Deis ignored relevant findings from an authoritative prior forum and, second, that these findings contradict the NFP Deis analysis on California air quality impacts.

The comment refers to proceedings before the California Public Utilities Commission (CPUC) to consider the requests of California investor-owned utilities (IOUs) to participate in the Third AC project. The CPUC ultimately denied the IOU requests due to insufficient showing of cost-effectiveness and uncertainty regarding adequacy of PNW power supply over the life of the project to assure the financial integrity of the project. (CPUC Decision 91-04-071, April 24, 1991.) The proceedings did not result in findings on the air quality impact of the Third AC, although some testimony was submitted but excluded from the record. The excluded testimony concerned residual emission costs from operation of plants owned by

IOUs, rather than the California publicly owned entities that eventually became the owners and operators of the California portion. The adverse residual air emissions were linked to increased generation at older, more environmentally harmful plants owned by IOU parties.

The comment fails to mention that the analysis produced for that forum dealt with a scenario that never came to reality, i.e., California IOU participation in the Third AC. The issue raised by parties before the CPUC as referenced by the comment was whether the use of the Third AC by IOU's would result in incentive for IOUs to preserve and run older, more environmentally harmful thermal plants to make deliveries to the PNW. The NFP Deis analysis assumes use of the Third AC by the publicly owned entities that ultimately participated in it. However, the NFP Deis also looks at overall use of the Intertie, of which the Third AC is a part, and does not neglect to analyze potential changes in IOU resource operations. The Deis assessed changes in expected resource operation and resource development by all California parties.

The comment also referred to page S-6 of the Deis summary on "Resource Acquisition Changes and Environmental Effects." This section will be revised to more completely summarize the analysis in Chapter 4 on expected California resource development. Chapter 4 explains that the California State regulatory environment would apparently not support in-State thermal resource additions to serve new Intertie contracts involving the IOUs subject to State regulation. However, the same State regulation does not apply to municipal or publicly owned utilities. These parties may have an interest in developing or acquiring from independent power producers new resources to support new Intertie transactions.

Chapter 4 analysis acknowledges that impacts would depend on the contracts eventually negotiated by the parties. The analysis gives the range of air quality impacts that might be seen under different contract scenarios. Further, the analysis refers to recent PNW-PSW environmental exchange contracts, which did successfully provide economic and environmental benefits. Chapter 4 also explained that the available data on preferred commercial transactions tends to indicate that Capacity Ownership and other Intertie access can be expected to result in a diverse mix of contracts, rather than a predominance of new resource development.

It should also be noted that the comment incorrectly holds the NFP Deis to account for projected air quality impacts of the Third AC line itself, an action that has already been taken based on past environmental analysis and decision processes. The NFP eis looks at BPA's

alternatives for granting access to PNW parties. Air quality and other impacts due to the addition of the Third AC (a.k.a. California-Oregon Transmission Project or COTP) were covered in BPA's Intertie Development and Use eis, April 1988, as explained in the NFP Deis Chapter 1.

Commenter: John T. Keck, State Historic Preservation Officer, State of Wyoming

Comment # 3ACP-10-0017

Response:

BPA does comply with the requirements of Section 106 of the National Historic Preservation Act and Advisory Council regulations. Because the NFP Deis analysis indicated that no significant environmental changes were expected to occur that would affect cultural resources in the study area, including the State of Wyoming, site-specific documentation is not called for.

Commenter: Rod S. Miller, Federal Land Planning Coordinator, State of Wyoming

Comment # 3ACP-10-0018

Response:

BPA will consider requests for additional non-Federal participation after a decision has been reached on the NFP eis. If BPA's decision is to proceed with the 725 MW Capacity Ownership preferred alternative, BPA would intend to substantially complete implementation before considering a follow-on process to offer additional capacity. The NFP eis includes analysis of non-Federal participation cases larger than 725 MW which provide environmental impact analysis that could be used to inform later decision processes on increased non-Federal participation.

Commenter: Roberta Palm Bradley, Superintendent, Seattle City Light

Comment # 3ACP-10-0020

Response:

I. The first comment agrees with Deis analysis affirming that seasonal exchanges that make use of PNW flows for fish purposes can benefit both the PNW and PSW environments and efficiency.

2. The second comment acknowledges the Deis qualitative analysis linking increased Intertie access with increased autonomy and therefore with increased development relative to that which BPA might have done. The comment correctly points out that parties will not necessarily use this autonomy to justify additional resource development. The Deis is in agreement and specifically pointed out in Chapter 4 that the information available on desired Intertie transactions would indicate that the Intertie will be used for a diverse mix of transactions.

3. The third comment (beginning in the fifth full paragraph of the letter) refers to the Deis analysis at pp. 4-4 and 4-18, which references potential contract negotiations to produce net decreases in air emissions and other impacts. The comment asks for examples of suggested mitigation or contract arrangements that would be beneficial in this sense. An example is actually given on p. 4-18, where the Deis analysis mentions the flexibility available through contract negotiation. In the second half of the second full paragraph on p. 4-18, the Deis

describes how a California party (SCE in the example cited) was able to supply energy for its winter return obligation from sources with low air emission concern, including PNW hydro-generated power.

The comment includes a minor error when it says that the Deis claims that capacity sales contracts can result in net air emission decreases. The referenced analysis on p. 4-18 concerned capacity-for-energy or power-for-energy environmental exchanges in which the capacity received is paid for in exchange energy rather than dollars. In the CEC process considering environmental exchanges (cited in Chapter 4 of the Deis), there were concerns raised that exchange transactions would only increase air emissions, since they would require extra generation to provide the exchange energy in return. In answer to this issue, the Deis specifically looked at whether environmental exchanges could be structured to decrease overall emissions. In capacity sale arrangements, capacity is paid for in cash, so they have not raised the same air quality concern.

4. The next comment requests an update on the list of parties actively pursuing Capacity Ownership at this time. The Latest list of actively interested parties will be included in the Final eis in Chapter 3 under the description of the Capacity Ownership alternative.

5. The last comment concerns the + or - signs used in a table in which changes are given in aMWs and as percent of base case. In the Deis, Table 4-8, a decrease in aMW is expressed as "-X MW" and an increase as "X MW". The percents are not signed positively or negatively, since they are simply proportions of a base total. It is assumed that readers can see the direction of change by the sign on the MW number given first.

Figure (Page H8 U.S. DEPARTMENT OF ENERGY...)

September 30, 1993

Public Involvement Manager
Bonneville Power Administration
P.O. Box 12999-ALP
Portland, OR 97212

RE: Non-Federal participation Deis

Dear Sir or Madam:

BPA's Non-Federal Participation in AC Intertie Draft Environmental Impact Statement (Deis) is deficient and must be redone or supplemented if it is to comply with your stated goals or the National Environmental Policy Act (NEPA). Some of the Deis's deficiencies are as follows:

1. The addition of multiple new owners to the northern portion of the subject intertie would allow southern utilities to be more successful in their quest for the lowest price energy when buying surplus energy. This drives down the net revenue from the line to the Northwest and Bonneville. By reducing BPA's ability to meet its treasury obligation, non-Federal participation violates the Deis's first stated need, the Bonneville Project Act and the Pacific Northwest Electric Power Planning And Conservation Act.

2. BPA's second statement of need for the project assumes that the PSW has a large capacity surplus in the winter. This assumption is unsupported and false. Also, the proposed action is not

required in order to make use of the diversity. An action that can happen with or without the proposal is not a need addressed by the proposal.

3. BPA's third and final "need" (to exchange energy) is similarly unrelated to the proposed action. BPA has made no valid stated of "need".

4. The most basic premise of the Deis analysis is false. For example, on page S-4 BPA states, "Differences in non-Federal autonomy would not change the West Coast market influences...". A Northwest utility which spends tens of millions of dollars to own an intertie to California must use the intertie to a great extent to recoup its investment. Conversely, not owning the intertie makes it preferable for a northwest utility to market surplus energy to the south only when the economic advantage is sufficient to cover the line usage costs. This is a major change in "market influences".

5. This eis violates NEPA by labeling increased hypothetical new resources as a "maximum" effect when in fact new resources is the likely effect (as noted, in part, in the above items).

6. Increased usage of highly polluting coal plants in the North-west due to the incentive for export created by non-federal par-participation is a serious impact that is inadequately addressed in the Deis.

7. The assessment of air quality impacts neglects findings by the California Public Utilities Commission (CPUC). In part the CPUC found that third AC usage would decrease air quality in Califor-nia due to increases in generation to compensate for energy lost in transmission and due to older more inefficient plants in California being kept in service longer. Page S-6 of the Deis references these deferrals implying a benefit from the preferred action when an environmental cost is the actual result.

Sincerely,

Gregory H. Bowers
1930 N. 122nd Street
Seattle, WA 98133

MIKE SULLIVAN
THE STATE OF WYOMING
GOVERNOR

700 W. 21ST STREET (307) 777-7427 CHEYENNE, WYOMING 82002
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COMMISSION SECRETARY
DEPUTY CHAIRMAN
STEPHEN G. OXLEY
STEVE ELLENBECKER
ADMINISTRATOR
COMMISSIONER

MEMORANDUM

TO: MR. ROD S. MILLER
FEDERAL LANDS COORDINATOR
STATE PLANNING COORDINATOR'S OFFICE

FROM: JON F. JACQUOT
CHIEF ENGINEER
PUBLIC SERVICE COMMISSION

DATE: SEPTEMBER 28,1993

RE: BONNEVILLE POWER ADMINISTRATION DRAFT ENVIRONMENTAL IMPACT STATEMENT FOR NON-FEDERAL PARTICIPATION IN THE AC INTERTIE, STATE IDENTIFIER NO. 92-071

Thank you for the opportunity to comment on the referenced document. The Commission wishes to advise you it has no objection to the document.

The three Wyoming electrical utilities who purchase power from Bonneville Power Administration and who use the Bonneville electrical transmission system (PacifiCorp; Lower Valley Power and Light, Inc.; and Fall River Rural Electric Coop., Inc.) fully support the scheme developed by Bonneville for non-federal participation in the third AC intertie between Oregon and California. They see it as a means by which to market any excess generating capacity they have to California.

PacifiCorp has asked for our support in encouraging Bonneville to increase the amount of capacity available for non-federal participation. Because of the limited amount of capacity Bonneville has made available for non-federal participation, PacifiCorp was precluded from purchasing capacity on the line. PacifiCorp is not allowed to purchase capacity on the third AC intertie as it has done on the other two AC interties. PacifiCorp is, however, not precluded from using the third AC intertie. Bonneville has offered PacifiCorp a transmission service contract for use of the line.

Any support given by this Commission should not be construed as rate making approval. Any rate effects of the referenced matter will be dealt with in appropriate, later proceedings.

If you should have any questions regarding this matter, please let me know.

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DIVISION OF PARKS Wyoming
& CULTURAL RESOURCES
Department of Commerce

State Historic Preservation Office
2301 Central, Barrett Bldg.
Cheyenne, Wyoming 82002-0240
(307) 777-7697
FAX (307) 777- 6421

September 27, 1993

BPA
Public Involvement Manager
P.O. Box 12999-ALP
Portland, OR 97212

RE: Department of Energy Bonneville Power Administration Availability of the Non-Federal Participation in AC Intertie Draft Environmental Impact Statement, SHPO #0993KLK071

Dear Sir:

Karen Kempton of our staff has received information concerning the aforementioned draft environmental impact statement. Thank you for giving us the opportunity to comment.

Management of cultural resources on Department of Energy projects is conducted in accordance with Section 106 of the National Historic Preservation Act and Advisory Council regulations 36CFR800. These regulations call for survey, evaluation and protection of significant historic and archeological sites prior to any disturbance. Provided the Department of Energy follows the procedures established in the regulations, we have no objections to the project. Specific comments on the project's effect on cultural resource sites will be provided to the Department of Energy when we review the cultural resource documentation called for in 36CFR800.

Please refer to SHPO project control number #0993KLK071 on any future correspondence dealing with this project. If you have any questions contact Ms. Kempton at 777-6292 or Judy Wolf, Deputy SHPO at 777-6311.

Sincerely,

John T. Keck
State Historic Preservation Officer

JTK:KLK:klm
cc: State Planning Coordinator

Mike Sullivan
Governor

R.D. "Max" Maxfield
Director,
Department of Commerce

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STATE OF WYOMING
OFFICE OF THE GOVERNOR
CHEYENNE 82002

MIKE SULLIVAN
GOVERNOR

October 7, 1993

Mr. Roy B. Fox
NEPA Compliance Officer
Office of Power Sales
Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

Dear Mr. Fox:

Please find enclosed comments from the Wyoming Public Service Commission relative to the Draft Environmental Impact Statement for Non-federal Participation in the AC Intertie. The State of Wyoming appreciates this opportunity to review the subject document. Please keep this office informed as to future developments.

Sincerely,

Rod S. Miller,
Federal Land Planning Coordinator

cc: PSC

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GOVERNOR'S OFFICE OF PLANNING AND BUDGET
Resource Development Coordinating Committee

Lynne N. Koga, CPA
Office Director
Brad T. Barber
State Planning Coordinator
Rod D. Millar
Committee Chairman
John A. Harja
Executive Director

116 State Capitol
Salt Lake City, Utah 84114
Phone: (801) 538-1027
Fax: (801) 538-1547

October 22, 1993

Bonneville Power Administration
Public Involvement Manager
PO Box 12999-ALP
Portland, Oregon 97212

SUBJECT: Non-Federal Participation in AC Intertie - Deis
State Identifier Number: UT930816-010

To Whom It May Concern:

The Resource Development Coordinating Committee, representing the State of Utah, has reviewed this proposal and has no comments at this time.

The Committee appreciates the opportunity to review this proposal. Please direct any other written questions regarding this correspondence to the Utah state Clearinghouse at the above address or call Carolyn Wright at (801) 538-1535 or John Harja at (801) 538-1559.

Sincerely,

Brad T. Barber
State Planning Coordinator

BTB/ar

H14

Seattle City Light

Roberta Palm Bradley, Superintendent
Norman B. Rice, Mayor

October 26, 1993

Roy B. Fox,
Bonneville Power Administration,
Office of Power Sales - PG
P. O. Box 3621
Portland, Oregon 97212

Draft environmental Impact Statement on Non-Federal Participation in the Third AC Intertie

Thank you for the opportunity to comment on the subject Deis. Seattle City Light (SCL) has reviewed this document and has the following comments:

First, we agree with Bonneville's analysis that true seasonal exchanges have the potential to be beneficial to the environment. To the extent that exchanges are timed in synch with non-energy requirements such as fish flows they can assist in protecting these elements of the environment. By operating the Northwest and Southwest systems in a more integrated fashion and by using their seasonal differences the efficiency of both systems can be improved. Your analysis affirms that with seasonal exchanges it may be possible to postpone construction of planned new resources.

Secondly, we acknowledge that assured access to the Intertie would offer owners increased autonomy and business certainty. This, the Deis concludes, could "increase the probability of long-term firm transactions for capacity sales, and even new resource development by non-federal participants."

While we recognize this possibility, we believe that not all utilities would follow this path. Seattle City Light, for one, does not intend to build any new resources for the purpose of firm capacity exports. In fact, in our Determination of Non-Significance (DNS) published in November 1992, SCL indicated that participation in the Third AC and the two exchange contracts was likely to result in reducing the Utility's need for new resources.

There are several places in your Deis (page 4-4, 4-18, etc.) where you state that even for capacity sales contracts, "contract negotiations can produce arrangements which result in net decreases in air emissions and other impacts". It

would be most appropriate in this eis for Bonneville to give examples of suggested mitigation or contract arrangements that would be beneficial in this sense.

Table 2-3 on page 3-9:

Last June all parties that were seriously interested in share of the Third AC Intertie submitted to Bonneville copies of Intertie-related contracts. several parties listed in Table 2-3 are no longer actively pursuing this option with you. Thus, this table needs to be updated to reflect the final list of participants and their expected allocations.

Finally, one minor correction:

In Table 4-8 on page 4-17, seasonal exchanges are expected to result in a net decrease in exports to the PSW (-21 to -169 aMW). This conclusion should be reflected in not only the "aMW" row, but also in the "percent base case" row. Please insert negative signs in that row, too, to accurately portray the expected trend.

Again, thank you for this opportunity to comment on the Deis. We look forward to continuing the discussions leading to the preferred option of an ownership share for non-federal participants.

Sincerely,

Roberta Palm Bradley
Superintendent

EE:ee

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Appendix I Bibliography

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