PACIFICORP

RESOURCE AND MARKET PLANNING PROGRAM

RAMPP – 6

INTERIM REPORT

DECEMBER 31, 1999

PacifiCorp RAMPP 6
Interim report to the Oregon Public Utility Commission
December 31, 1999

Background

On November 20, 1998, PacifiCorp requested a one-year extension of the filing date for the Company's sixth Least Cost Plan (RAMPP 6). It was apparent to the Company at that time that changes in the industry were adding a level of complexity to long range planning. The additional year was to be used to explore the implications of many of these changes.

1999 demonstrated the pace of change in the electric industry. In December of 1998 PacifiCorp announced a merger with ScottishPower. This merger was completed at the end of November 1999. Also during 1999 the Oregon legislature passed electric industry restructuring legislation. This legislation provides for direct access to third party energy service providers for larger customers and a portfolio of electric service options for smaller customers in addition to the traditional cost of service based service. The legislation also created a system benefits charge to be paid by customers of PacifiCorp and PGE to fund demand side programs including low income weatherization, encourage renewable development, and support conservation efforts in education service districts. In Oregon, system benefits charge replaces the utility's obligation to achieve cost effective energy savings as indicated in their Least Cost Plan.

Another major change in the electric utility industry in the West is the effort by the BPA to replace the Residential Exchange program for delivering Federal power benefits to qualifying IOU residential and small farm customers with a subscription program. One option of the subscription program is to deliver actual power to the IOUs for the benefit of their qualifying customers. This product will be a substantial amount of firm, 100% capacity factor energy. Subscription is expected to begin October 1, 2001. Accommodating this energy into the system and ensuring that its benefits flow only to qualifying customers while not imposing undue costs on other customers will be a new challenge.

It is likely that the pace of change will continue as the states and federal policy makers wrestle with the concepts behind industry restructuring. The Least Cost Planning process will need to evolve to recognize changes such as portfolio options, third party energy suppliers and system benefit charge based conservation and renewable development. In the discussion that follows, PacifiCorp presents the status of RAMPP 6 and details discussions held with the RAMPP Advisory Group through a series of meetings held during late 1998 and throughout 1999.

The Commission granted PacifiCorp's request for a one year extension in Order number 99-282. The order directed the Company to prepare a report by the end of 1999 that addressed the following issues:

1) An action plan for the years 2000 and 2001
2) A status report of current projects
3) Load forecast
4) Long-term sales contracts
5) Power purchases during 1998 and 1999 as well as those anticipated for 2000 and 2001
6) Wind power construction and operation
7) DSM implementation
8) System reliability investigations
9) Specific System improvements in distribution, generation and transmission for 1998 and 1999 as well as those anticipated for 2000 and 2001
10) Funding mechanisms for DSM and renewables
11) Resource acquisition efforts
12) Resource sales, if any
13) Transmission changes
14) Regulatory changes within PacifiCorp's service territory

These topics are addressed below.

Action plan

The RAMPP 5 action plan included an action plan for demand side resource acquisition, continued system efficiency improvements and other opportunities. RAMPP 5 was acknowledged by the Commission in Order No. 99-279. While the RAMPP 5 action plan encompassed only the years 1998 and 1999 the RAMPP 5 analysis was for the period 1998 through 2017. The RAMPP 5 base case indicated that the Company did not need to add new resources, other than DSM, until after 2012. The Company also developed a revised base case that removed the impacts of the assumption of a 10% loss of load and the balancing of wholesale sales with wholesale purchases and included the assumed sale of the Company's Montana and California service territories. The balancing of wholesale sales adjustment had been made to insulate the retail customer from activity in the wholesale market. With the revised base case, the Company will not need new resources until 2005-2006 and will not need to make a decision on the acquisition of new resources until 2003-2004. The Company believes that the action plan for new generation remains unchanged from the RAMPP 5 analysis. No generation acquisition is called for in the 2000 to 2001 time frame.

RAMMP 5 indicated that between 1.79 and 3.11 aMW of demand side resources should be acquired in Oregon and between 9 and 13.5 aMW system-wide each year across the 20 year planning horizon. DSM must be acquired in advance of need due to the lead-time required to acquire a substantial amount of resource. The amount of DSM to be acquired is a function of the cost of the demand side resources, the year and the size of the resource deficit, the cost of alternative generation resources and the cost of market purchases.

As part of its commitments made during its merger with ScottishPower the Company has convened an Oregon working group to evaluate the DSM potential within PacifiCorp's Oregon service territory. This working group has met on several occasions to evaluate the potential and to provide input on the design of new programs and revisions to existing programs to capture that potential.

Following discussions within the Group, the following targets were broadly agreed:

Year	Target (aMW)	Notes
2000	3	150-200% of current
2001	4	200%+ of current
2002 - forward	4-7	SB1149 era

These targets are within the range suggested by the RAMPP 5 analysis and will be adopted as the action plan for DSM for the years 2000 and 2001. The DSM action plan in other jurisdictions will similarly follow the targets established in RAMPP 5. It should be noted that effective October 1, 2001 the Oregon restructuring legislation will be implemented. This legislation provides for a system benefit charge to fund DSM acquisition after that date.

The RAMPP 5 action plan also indicated that the Company will continue to make cost effective improvements to the existing generation, transmission and distribution systems. This action item will be continued into 2000 and 2001. In the merger proceedings ScottishPower emphasized a desire to continually improve the operation of the existing system. Specifically, the merger orders in the various jurisdictions contain stipulations agreed to by ScottishPower related to network performance and customer guarantees..

The final RAMPP 5 action plan item was to pursue cost effective resource acquisition opportunities that meet the future needs of the Company. The RAMPP 5 analysis did not indicate an immediate resource need. Nonetheless it is prudent that the Company continue to evaluate all potential opportunities as they present themselves. This action item will continue in 2000 and 2001.

Status of RAMPP 6

RAMPP 6 has been under development since October of 1998. Six RAMPP Advisory Group meetings have been held. Below is a chronology of the meetings and the topics presented and discussed.

October 2, 1998
- RAMPP 5 Acknowledgements
- Risk Analysis Techniques – Ken Powell, DPU
- Defining components and timing of RAMPP 6

February 19, 1999
- RAMPP 5 Acknowledgements
- RAMPP 6 Extension requests
- Incorporating wholesale activity into RAMPP

	- Revisions to the load forecasting model
May 7, 1999	- Current resources - Wholesale sales - Wholesale purchases - Depreciation lives - Centralia sale impact - Status of revisions to load forecasting
July 9, 1999	- Northwest regional load and resource balance – Wally Gibson, NWPPC - DSM - Load forecast - The role of IRP in a restructured industry
September 10, 1999	- Transmission system changes and upgrades - Distribution system changes and upgrades - Final load forecast - 2000 Action plan
November 22, 1999	- Review of final load forecast - Fuel prices - Market prices - Wind Power update - Plant lives for RAMPP 6 - Clean Air Act enforcement - Scenario planning - 2000 DSM action plan

Least cost planning consists fundamentally of identifying the expected load to be served and matching that load with the "least costly" mix of resources. The resources will be a combination of existing resources, new and existing market purchases, new generation resources and new demand side resources. The definition of "least costly" resources incorporates the concept of future uncertainty. Thus, absolute least cost based on today's technologies, costs, tax structure and environmental controls may not be the least cost over a 20 to 50 year horizon. Resource diversification strategies will be employed to minimize risk from significant cost shifts.

One of the recurring themes during the six meetings held to date in the development of RAMPP 6 is the definition of future load. Restructuring occuring within PacifiCorp's service territory raises the question "Who does least cost planning plan for?" A further discussion of the issue is presented below in the discussion of load forecast.

A second recurring theme is how the market should be incorporated in the planning. Historically, the market for fuel prices and the market for wholesale purchases have been discernable. Long term contracts and consistency in the market structure have allowed for the incorporation of definitive market forecasts, often cast into several stratas (high, medium, low) to allow for changes in forecast demand. The market is currently, very difficult to analyze. Restructuring in the electric industry and a shift to gas as the fuel of choice for future generation have lead to volatility in the markets.

RAMPP 6 will incorporate natural gas and market price forecasts in a manner designed to allow for risk analysis of alternative futures. A risk analysis tool was presented at the October 2, 1998 RAMPP advisory group meeting by Ken Powell of the Division of Public Utilities in Utah. This tool evaluates a large number of potential futures weighted by impact and likelihood. The resulting analysis will provide valuable input to the RAMPP 6 plan. To recognize the uncertainty in natural gas and market price forecasts, RAMPP 6 will use a range of natural gas and market price starting points coupled with a range of future escalation rates to generate a large number of potential natural gas and market price scenarios. Market price escalation will be coupled to natural gas price escalation to assure a reasonable link between the two. This is a distinction between RAMPP 6 and its predecessors, which had a specific fuel price, and market price identified as the base case or most likely estimate.

PacifiCorp anticipates bi-monthly meetings beginning in February to present the planning scenarios identified by the RAMPP advisory group. By early summer the scenarios will be analyzed using the risk analysis approach. In early fall the draft RAMPP 6 document will be presented for comment to the RAMPP advisory group with a target completion of the final RAMPP 6 in December 2000.

Load Forecast

The load forecast is a fundamental aspect of least cost planning. Restructuring occurring within PacifiCorp's service territory raises several issues including:

- What time horizon is the load forecast for?
- What customers will remain regulated?
- What is the obligation to plan resources for unregulated customers?
- What is the obligation to plan resources for default customers or customers that return to PacifiCorp's system?

These issues will remain largely unresolved during the development of RAMPP 6. Consequently, for the purposes of planning a decision was made to assume that the existing regulated customers would remain within the planning threshold of RAMPP 6 over the planning horizon. This is a conservative assumption compared to the RAMPP 5 assumption of gradual loss of regulated customers. It represents a scenario whereby the RAMPP 6 plan encompasses all current customers, with associated new regulated customers and load growth. It is likely that within the 20 year planning time frame a number of these customers will no longer purchase their energy from PacifiCorp as a regulated integrated utility. Since no basis could be established to estimate the load lost and no resolution is currently available to the issue of whom the least cost planned resources encompass, RAMPP 6 will address this probability through scenarios that vary the load forecast.

Appendix A is the base load forecast presented at the November 22, 1999 RAMPP Advisory Group meeting.

Long-term sales contracts

Appendix B is a summary of the current resources, long term sales contracts and long term purchase contracts. Included in the summary is a list of changes to these resources and contracts from RAMPP 5.

Power purchases during 1998 and 1999 as well as those anticipated for 2000 and 2001

Appendix C is a listing of 1998 power purchases. 1999 information is not yet available. 2000 and 2001 anticipated purchases are identified in Appendix B.

Wind Power construction and generation

In fall of 1998 the Company's Wyoming wind project at Foote Creek Rim began generating electricity. The project has a total capacity of 41.4 megawatts. PacifiCorp owns 80% of the project. Eugene Water and Electric Board owns the remainder. Appendix D is a summary fact sheet regarding the project and a summary of the latest 1999 generation information.

DSM implementation

Appendix E is the Company's Annual Review of Energy Efficiency Programs for 1998 in Oregon. In 1999 the Company filed Advice Number 99-007 to revise the measure funding limits for the Finanswer program. Also included in that filing were revisions to the square footage definition, the deletion of screw-in CFLs from eligibility, the clarification of the baseline for florescent lighting and the addition of a temporary closing incentive to encourage program participation. The Commission approved these changes at the October 18, 1999 public meeting.

System reliability investigations

At the September 10, 1999 RAMPP advisory group meeting, Tom Waters, Manager of Area Planning and Engineering described the Company's system reliability study process. PacifiCorp has divided its local transmission system into 48 study areas. Reliability studies are planned to be updated every 3 years on each of these areas, once baseline studies are completed. Appendix F is a copy of the planning presentation.

System improvements in generation

The Company has been in the process of increasing the efficiency of existing coal plants with turbine upgrades and other measures. Specific changes in capacity will be incorporated in the RAMPP 6 model.

System improvements in transmission and distribution

In 1999 PacifiCorp will have installed an additional 324 MVA of distribution substation capacity to meet expected load increases. 1999 expenditures were planned to be about $23M.

Additionally, in 1999 the Company plans to complete a number of major transmission reinforcement projects that were started in past years. These include the Midvalley-Cottonwood Project, the Second Midvalley Transformer Project, and the Butlerville Project. During the year work was begun on a number of other transmission projects which will be completed in future years. These include the Bend Reinforcement Project, the Gadsby A&B Line Project, and the Dimple Dell Loop-in Project. Total 1999 expenditures in this activity were planned to be about $18M.

Two-thirds of transmission and distribution capital expenditures are made in "blankets" (blankets are capital projects that consist of numerous projects too small to warrant separate identification). These include thousands of small projects to connect new customers, repair deteriorated lines and substations, and make upgrades to the transmission and distribution system such as increased automation, etc.

Funding mechanisms for DSM and renewables

In 1996 the "Comprehensive Review of the Northwest Energy System" was published. This collaborative effort by the Governors of the four northwest states recommended funding DSM and renewable development as a percentage of retail sales. Specifically, the report recommended the following funding:

Local conservation	1.6%
Low-income weatherization	0.4%
Renewable resources	0.57%
Conservation Market Transformation	0.43%
TOTAL	**3.0%**

These recommendations have been used as a basis for suggesting new funding mechanisms in several of PacifiCorp's jurisdictions. In Oregon Senate Bill 1149 enacted restructuring which specified 3% public purpose expenditure. The bill requires that 10% be distributed to education service districts. The remaining 90% is distributed as follows:

Local conservation and market transformation	63%
Above market costs of new renewables	19%
Low income weatherization	13%
Housing and Community Services Department	5%

Effective October 1, 2001 this public purpose funding mechanism will replace the existing mechanisms for DSM and renewables expenditures.

Currently in Oregon, PacifiCorp has a System Benefit Charge that recovers the costs of DSM and renewables. Rather than a fixed percent of revenues this mechanism is designed to recover the prior year's investment in these areas. This mechanism will be superceded by the SB 1149 mechanism on October 1, 2001 for new investments.

Resource Acquisition Efforts

The Company has not acquired new resources other than those discussed in the Wind Power discussion above.

Resource Sales

On August 6, 1999 the Company filed an application before the Oregon Commission requesting approval of the sale of the Centralia Steam Electric Generating Plant, the ratebased portion of the Centralia Coal Mine and related facilities. See Appendix G for a copy of the application.

A voluntary agreement among the Yakima Nation, PacifiCorp, environmental groups and state and federal fishery agencies has been reached to remove Condit Dam on the White Salmon River in southwestern Washington State. The agreement allows Condit to continue operating for the next seven years to help generate funds to offset dam-removal costs.

The Company has put up for sale the Big Fork hydro project in Montana. PacifiCorp has received 3 tentative bids for the 4-megawatt hydro project. The sale is currently on hold, however, pending internal reviews and approvals.

Transmission Changes

Appendix G is a presentation made by Kurt Granat, Senior Engineer in Resource and Transmission Planning at the September 10, 1999 RAMPP advisory meeting. The presentation describes changes associated with implementation of FERC orders 888 and 889, regional independent grid operators and transmission path rating changes.

See also System Improvements in Transmission and Distribution.

Regulatory Changes within PacifiCorp's service territory

On July 23, 1999 Governor John A. Kitzhaber signed Senate Bill 1149 into law. SB 1149 provides direct access for non-residential customers, a portfolio of choices for residential and small commercial customers and a system benefit charge funding mechanism for DSM and renewable generation projects and a low income bill assistance charge. The Bill will be fully implemented by October 1, 2001. The Bill directs the Oregon Commission to develop the implementation details.

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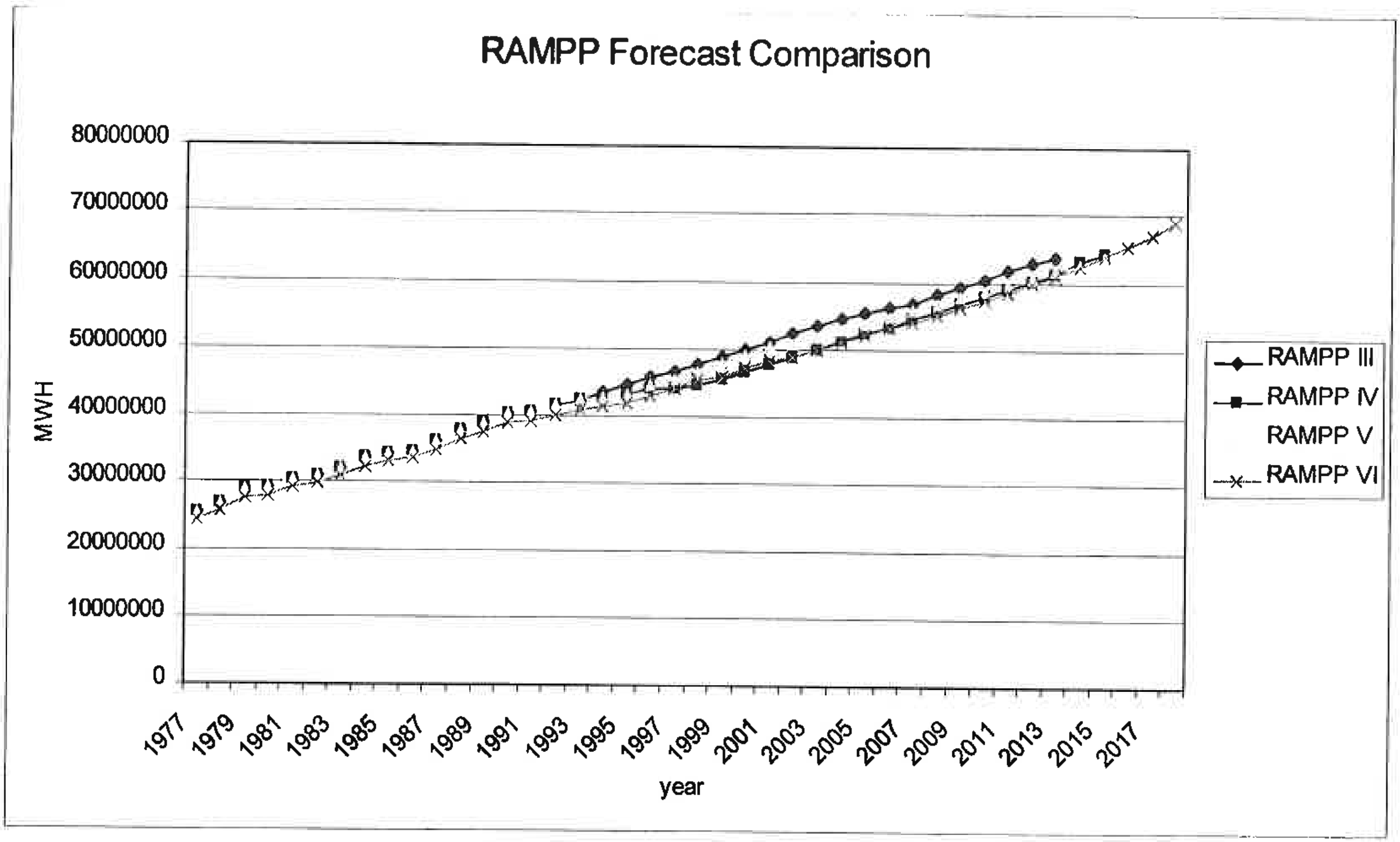
1999 TO 2018
Load Forecast
RAMPP VI

Changes To Forecast

- Omissions
  - Montana
  - California
- Additions
  - Four Scenarios
    - Baseline Forecast
    - 25% Above Baseline
    - 25% Below Baseline
    - Baseline Model with Utah Growing at 4.5% per year


RAMPP Forecast Comparison
80000000
70000000
60000000
50000000
40000000
30000000
20000000
10000000
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MWH
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1983
1985
1987
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2003
2005
2007
2009
2011
2013
2015
2017
year
RAMPP III
RAMPP IV
RAMPP V
RAMPP VI

Sector Growth Rates RAMPP Comparison
MWH

	– Historical	RAMPP III	RAMPP V	RAMPP VI
• Res	2.00%	2.01%	1.83%	2.26%
• Com	3.79%	2.52%	2.32%	2.25%
• Ind	3.73%	2.86%	1.61%	2.16%
• Irr	.67%	-.09%	.86%	.86%
• Other	.86%	1.09%	1.09%	1.19%
• Total	3.04%	2.02%	1.85%	2.17%

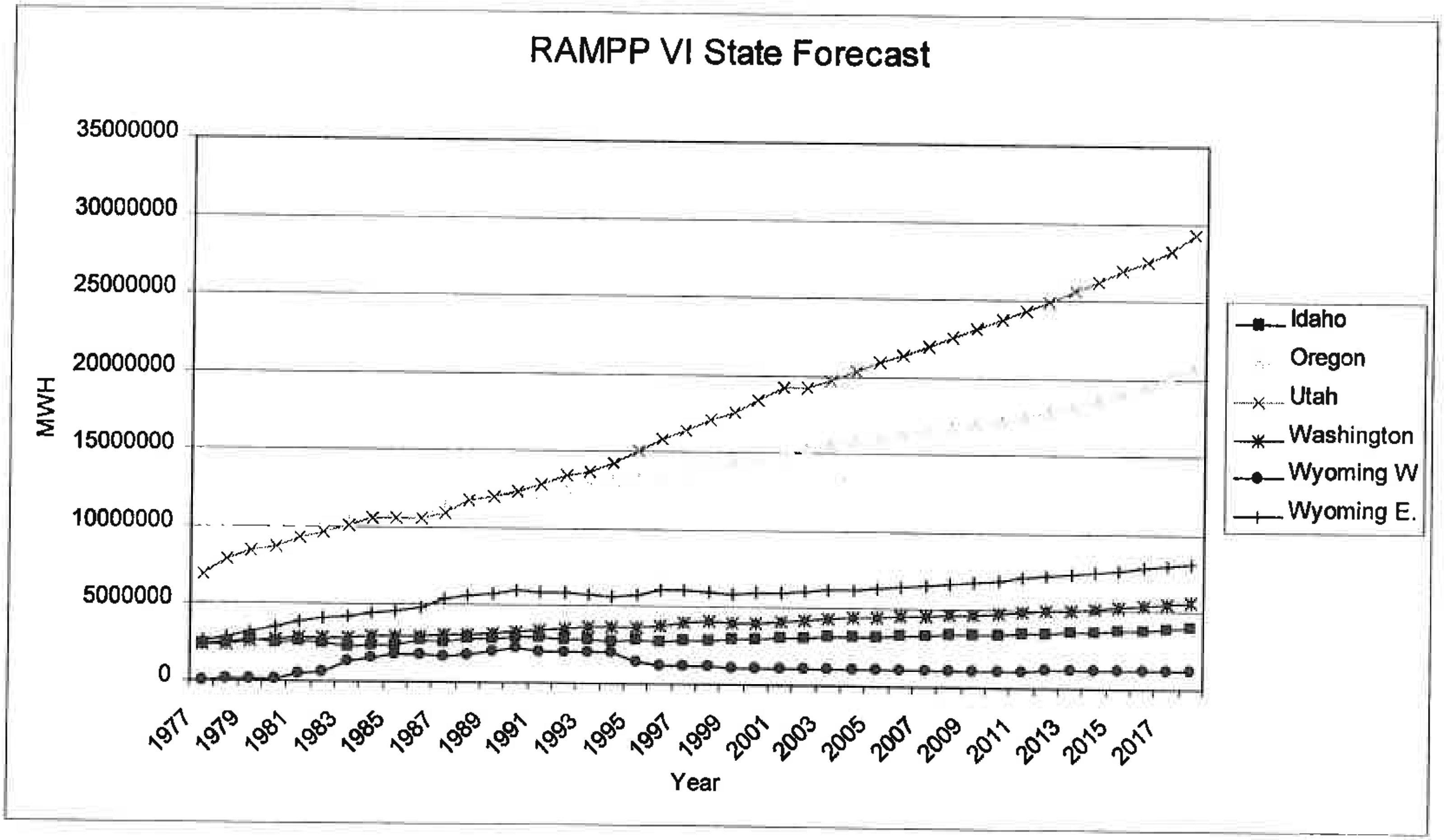
RAMPP Comparison

	RAMPP III	RAMPP IV	RAMPP V	RAMPP VI
1977	25321232	25321232	25321232	24205300
1978	26819216	26819216	26819216	25655012
1979	28855000	28855000	28855000	27611557
1980	29160835	29160835	29160835	27911582
1981	30389363	30389363	30389363	29139271
1982	30927876	30927876	30927876	29710264
1983	32117194	32117194	32117194	30886786
1984	33629536	33629536	33629536	32342090
1985	34277156	34277156	34277156	32996079
1986	34564343	34564343	34564343	33585811
1987	36066168	36066168	36066168	34775629
1988	37850815	37850815	37850815	36503422
1989	38932246	38932246	38932246	37541923
1990	40219280	40219280	40219280	38769534
1991	40567646	40567646	40567646	39107985
1992	41639251	41639251	41639251	40080055
1993	42230749	42438103	42438103	40827121
1994	43632714	42889736	42889736	41269722
1995	44634352	43438947	43438947	41802460
1996	45751689	44142129	44770024	42968524
1997	46754514	44259743	45611965	44152464
1998	47771262	44760151	46692048	45447781
1999	48800687	45606407	47918182	45774113
2000	49935919	46639528	49214065	47081651
2001	51102821	47728502	50458848	48381514
2002	52296820	48828397	50819230	48916235
2003	53499724	50031551	51838441	50004071
2004	54636955	51261767	52862762	51105250
2005	55435597	52304006	53841191	52178520
2006	56152632	53345258	54824481	53180866
2007	56881942	54486581	55864254	54162052
2008	58216361	55789630	56863041	55174899
2009	59368146	56879044	57823510	56270985
2010	60544274	58010659	58781102	57273877
2011	61720625	59143141	59772293	58421692
2012	62834637	60201603	60770562	59731121
2013	63843542	61183573	61742432	61054449
2014		63264614	62693941	62462391
2015		64260073	63675972	63895241
2016			64674254	65351469
2017				66925827
2018				68871036

RAMPP VI FORECAST

By Sector

	Residential	Commercial	Industrial	Irrigation	Other
1977	8169130	5276646	9267494	976800	515221
1978	8531723	5667146	10059420	875237	521486
1979	9080071	6076945	10913405	1004563	536573
1980	8999613	6137833	11359182	866321	548633
1981	9191764	6456173	11954723	978945	557666
1982	9520082	6681064	11996789	920206	592123
1983	9452862	6840880	13223116	793949	575979
1984	9714436	7130391	14108602	769172	619489
1985	9656825	7400849	14356012	932864	649529
1986	9570223	7589642	14493394	1264360	668192
1987	9635821	7884337	15671987	913364	670120
1988	9948905	8209179	16648994	1044435	651909
1989	10059433	8348958	17411466	1027309	694757
1990	10486806	8587498	17916710	1141594	636926
1991	10666646	8902329	17833048	1062757	643205
1992	10809404	9248854	18295760	1067609	658426
1993	11248287	9564795	18352992	990094	670954
1994	11339807	9775021	18559208	930602	665085
1995	11337542	10357645	18474565	945438	687250
1996	12047111	10995429	18266032	946465	713487
1997	12319014	11356311	18791844	953708	736702
1998	12361018	11834385	19448859	967346	746934
1999	12475930	12191522	19366108	973299	767254
2000	12822559	12736649	19749246	983036	790160
2001	13188176	13251449	20137780	993765	810344
2002	13391333	13178070	20548561	1002591	795680
2003	13661756	13530373	20994380	1012407	805155
2004	13842798	13915981	21514734	1015790	815947
2005	14045546	14240896	22041355	1023603	827121
2006	14238620	14554828	22518549	1030917	837951
2007	14428889	14864707	22980923	1038488	849046
2008	14627936	15182812	23458402	1045329	860421
2009	14827322	15507945	24010909	1053755	871054
2010	15028340	15844333	24458484	1059886	882834
2011	15303157	16180168	24976559	1068071	893736
2012	15779947	16518349	25450499	1077708	904619
2013	16276211	16862426	25913190	1087711	914910
2014	16778141	17211592	26449500	1098795	924363
2015	17327090	17563178	26962320	1110058	932593
2016	17884978	17911283	27491564	1121282	942361
2017	18438695	18239154	28164590	1133604	949785
2018	19067290	18622827	29075063	1145480	960378


RAMPP VI State Forecast
35000000
30000000
25000000
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MWH
1977
1979
1981
1983
1985
1987
1989
1991
1993
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2001
2003
2005
2007
2009
2011
2013
2015
2017
Year
Idaho
Oregon
Utah
Washington
Wyoming W
Wyoming E.

State Growth Rate Comparison
MWH

	Historical	RAMPP III	RAMPP IV	RAMPP V	RAMPP VI
Idaho	1.90%	1.26%	1.49%	1.53%	1.63%
Oregon	1.76%	1.94%	2.08%	1.97%	1.94%
Utah	4.67%	2.55%	2.17%	2.05%	2.71%
Washington	2.56%	2.24%	1.85%	1.74%	1.92%
Wyoming W	18.55%	-1.74%	-1.30%	-0.30%	0.56%
Wyoming E	4.77%	1.95%	1.46%	1.52%	1.71%

Historical & Forecast MWH Growth
By State

	Idaho	Oregon	Utah	Washington	Wyoming W	Wyoming E.
1977	2384018	9809706	6969665	2396694	52394	2592823
1978	2444304	10057999	7850087	2392498	60778	2849346
1979	2659175	10571071	8483525	2619373	78130	3200283
1980	2513869	10324014	8706353	2734226	130773	3502347
1981	2639106	10248662	9225325	2781341	416793	3828044
1982	2484996	10111479	9636584	2780672	605475	4091058
1983	2221896	10279456	10064351	2821176	1261143	4238764
1984	2306188	10627497	10518421	2916952	1526760	4446272
1985	2346650	10652267	10605857	2956332	1808609	4626364
1986	2705584	10804413	10585451	2951538	1763804	4775021
1987	2536003	11228229	10909742	3049721	1652010	5399924
1988	2833190	11486957	11775672	3099931	1717016	5590656
1989	2811933	11843828	11993920	3201631	1959143	5731468
1990	2891083	12162525	12324052	3279773	2180190	5931911
1991	2889366	12186955	12749454	3377517	1996169	5908504
1992	2855864	12415943	13438663	3541405	1972863	5855316
1993	2838208	12824597	13676833	3655219	2042304	5789960
1994	2708932	13050664	14207232	3615267	2036864	5650763
1995	2844486	13111896	15030657	3698303	1362399	5754719
1996	2707646	13303939	15889358	3796356	1122751	6148474
1997	2762697	13683103	16493450	3942986	1128228	6141799
1998	2813167	14275187	17107681	4099604	1124977	6027166
1999	2899663	14347991	17631774	3958082	1071034	5865568
2000	2956324	14568783	18495133	4050605	1053936	5956870
2001	3016083	14895824	19275298	4142811	1055921	5995577
2002	3070709	15231736	19223479	4227803	1074091	6088417
2003	3123436	15601311	19692071	4314471	1090537	6182244
2004	3165309	15883172	20290989	4413637	1094195	6257949
2005	3209182	16142603	20871630	4480510	1096304	6378290
2006	3253917	16359387	21424440	4549619	1099978	6493526
2007	3307495	16535868	21992470	4619820	1101308	6605091
2008	3348959	16738748	22579535	4688459	1100816	6718382
2009	3407952	16980892	23188145	4754550	1101572	6837673
2010	3435836	17227087	23709387	4824944	1102374	6974251
2011	3484595	17506080	24305285	4907787	1112031	7105914
2012	3544451	17837951	24955446	5000914	1129885	7262473
2013	3605433	18213764	25570385	5096737	1142284	7425846
2014	3672992	18646716	26239429	5203235	1154458	7545581
2015	3737787	19134778	26853001	5317007	1170000	7682688
2016	3802479	19625381	27500982	5429985	1171555	7821085
2017	3876882	20152009	28205600	5555816	1180300	7955220
2018	3940652	20671269	29288697	5678673	1190482	8101265

Forecast Assumptions

- Employment Growth Rates
  - By State by Industry Segment
  - Commercial Sector (by VMS)
  - Industrial Sector (by SIC Code)
- Population & Customer Growth Assumptions
  - Residential Sector by State
  - Commercial Sector by State

EMPLOYMENT GROWTH RATE ASSUMPTIONS
(by state by industry segment)

	BASIC EMPLOYMENT				NONBASIC EMPLOYMENT						
	Agri.	Mining	Manufacturin	Fed. Gov.	TCPU	Whole/Retai	FIRE	Services	Constructior	St.&Loc G.	Nonfarm P.
SIC	1,2,7,8,9	10,12,13,14	20 - 39	43,79,80,91-97	40 - 42,44 - 49	50 - 59	60 - 67	70,72,73,75-80	15,16,17	91 - 96	
California	-1.29%	0.52%	0.44%	-0.06%	-0.10%	3.07%	2.47%	1.97%	2.22%	1.55%	2.73%
Idaho	-1.15%	-0.71%	0.02%	-0.06%	-0.12%	1.16%	2.12%	1.45%	3.41%	1.36%	1.01%
Oregon	-1.20%	-0.43%	0.30%	-0.06%	0.46%	1.91%	0.92%	1.52%	-1.25%	1.40%	1.16%
Utah	-0.56%	0.18%	1.01%	-0.06%	2.34%	2.44%	2.15%	2.85%	1.63%	2.18%	3.16%
Washington	-0.03%	-0.02%	0.88%	-0.06%	0.98%	1.65%	2.09%	1.53%	0.81%	2.21%	1.20%
Wyoming W	0.00%	-2.36%	-0.22%	-0.06%	-3.30%	0.00%	1.35%	-2.79%	-1.40%	0.02%	3.57%
Wyoming E	0.20%	2.38%	-0.80%	-0.06%	2.21%	1.19%	1.84%	1.89%	2.28%	1.63%	1.17%

TCPU=Transportation, communication, Public Utilties

FIRE=Finance, Insurance, Real Estate

Customer Assumptions

RESIDENTIAL SECTOR

Service Territory Population Growth Rate						
California	Idaho	Oregon	Utah	Washington	Wyoming W	Wyoming E
1.89%	1.12%	1.17%	2.29%	1.41%	1.07%	1.67%

Service Territory Customer Growth Rate						
California	Idaho	Oregon	Utah	Washington	Wyoming W	Wyoming E
1.98%	1.64%	1.21%	2.88%	1.70%	0.77%	1.82%

Relative Price (electric price/ng price) (% Change)						
California	Idaho	Oregon	Utah	Washington	Wyoming W	Wyoming E
-0.32%	-0.39%	-0.46%	-0.38%	-0.46%	-0.39%	-0.39%

COMMERCIAL SECTOR

Customers Growth Rate						
California	Idaho	Oregon	Utah	Washington	Wyoming W	Wyoming E
1.57%	1.67%	1.22%	2.38%	1.11%	-0.86%	1.60%

COMMERCIAL SECTOR (BY VMS)
Employment Growth Rates

	VMS1	VMS2	VMS3	VMS4	VMS5	VMS6	VMS7	VMS8	VMS9	VMS10	VMS11	VMS12
SIC	40 - 42, 44 - 49	54	52, 53, 55 - 57	58	50, 51	70	82	805 & 806	80 less 805 & 806	3, 60 - 70 & 91 - 9	71 - 81, 83, 87	49, 88
	TCPU	Food Stores	Retail Stores	Restaurants	Wholesale trade	Lodging	Schools	Hospitals	Other Health S.	Offices	Services	Miscellaneous
Cal	-0.10%	3.66%	3.07%	4.21%	0.96%	1.97%	1.28%	1.25%	2.94%	1.62%	1.90%	2.18%
	TCPU	Food Stores	Retail Stores	Restaurants	Wholesale trade	Lodging	Schools	Hospitals	Other Health S.	Offices	Services	Miscellaneous
Idaho	-0.12%	1.74%	1.16%	2.28%	-0.75%	1.45%	0.76%	0.73%	2.41%	1.39%	1.38%	3.26%
	TCPU	Food Stores	Retail Stores	Restaurants	Wholesale trade	Lodging	Schools	Hospitals	Other Health S.	Offices	Services	Miscellaneous
Oregon	0.46%	2.49%	1.91%	3.04%	-0.04%	1.52%	0.83%	0.80%	2.46%	1.11%	1.44%	-0.79%
	TCPU	Food Stores	Retail Stores	Restaurants	Wholesale trade	Lodging	Schools	Hospitals	Other Health S.	Offices	Services	Miscellaneous
Utah	2.27%	2.86%	2.28%	3.41%	0.85%	2.85%	2.15%	2.12%	3.63%	1.88%	2.78%	1.67%
	TCPU	Food Stores	Retail Stores	Restaurants	Wholesale trade	Lodging	Schools	Hospitals	Other Health S.	Offices	Services	Miscellaneous
Washington	0.98%	2.23%	1.65%	2.78%	-0.73%	1.53%	0.84%	0.81%	2.50%	1.93%	1.45%	0.93%
	TCPU	Food Stores	Retail Stores	Restaurants	Wholesale trade	Lodging	Schools	Hospitals	Other Health S.	Offices	Services	Miscellaneous
Wyoming W	-3.30%	0.57%	0.00%	1.11%	-0.45%	-2.79%	-3.45%	-3.48%	-1.86%	0.20%	-3.22%	-1.44%
	TCPU	Food Stores	Retail Stores	Restaurants	Wholesale trade	Lodging	Schools	Hospitals	Other Health S.	Offices	Services	Miscellaneous
Wyoming E	2.21%	1.77%	1.19%	2.31%	0.65%	1.89%	1.20%	1.17%	2.86%	1.53%	1.81%	2.26%

TCPU= Transportation, communications, Public Utilities

INDUSTRIAL EMPLOYMENT GROWTH RATES
by state by sic

	Idaho			Oregon			
	Food & K	Lumber &W	Chemicals	Food & K	Lumber & W	Paper &Allied	Primary Met.
SIC	20	24	28	20	24	26	33
	-0.31%	-0.60%	1.39%	-0.24%	-0.82%	0.15%	0.12%

	Utah										
	Metal Mining	Coal	Oil & Gas	Mining	Food & K	Chemicals	Petrol Ref	Stone & Clay	Primary Meta	Electronics	Transportation
SIC	10	12	13	14	20	28	29	32	33	36	37
	0.00%	1.83%	-1.04%	0.00%	1.41%	0.22%	-1.68%	0.29%	-1.46%	0.92%	1.25%

	Washington			Wyoming							
	Food & K	Lumber &W	Paper &Allied	Misc Metals	Coal	Oil & Gas	Clay,Ceramic	Chemicals	Food & K	Lumber &W	Petrol Refine.
SIC	20	24	26	109	12	13	145	147	20	24	29
	0.37%	-0.60%	0.38%	0.00%	2.49%	3.60%	-0.65%	0.72%	-0.47%	0.58%	-2.22%

State Forecast

By Sector

Graph & Data

- Idaho
- Oregon
- Utah
- Washington
- Wyoming W.
- Wyoming E.

Energy Load Growth
By Sector By State

Idaho

	Residential	Commercial	Industrial	Irrigation	Other
1979-1998	1.09%	3.50%	0.26%	0.16%	-2.36%
1999-2018	2.44%	2.27%	1.38%	0.85%	0.00%

Oregon

	Residential	Commercial	Industrial	Industrial	Other
1979-1998	1.18%	2.57%	1.49%	0.58%	0.71%
1999-2018	1.84%	1.87%	2.18%	0.97%	0.00%

Utah

	Residential	Commercial	Industrial	Irrigation	Other
1979-1998	3.38%	5.14%	3.93%	1.38%	2.13%
1999-2018	2.76%	2.64%	2.87%	0.65%	1.30%

Washington

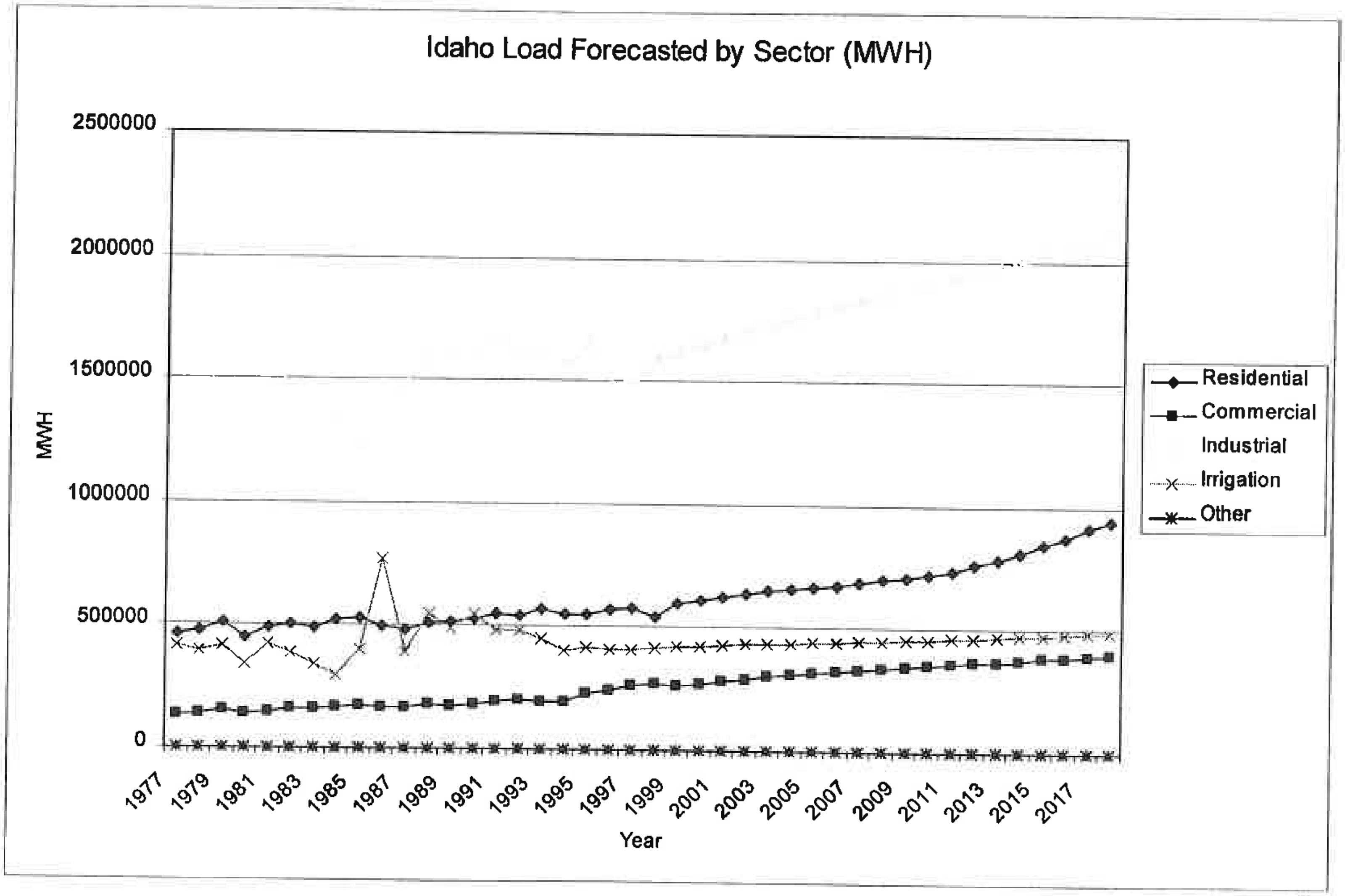
	Residential	Commercial	Industrial	Irrigation	Other
1979-1998	1.11%	3.22%	6.04%	0.34%	-1.10%
1999-2018	2.16%	1.83%	1.81%	0.90%	0.00%

Wyoming W.

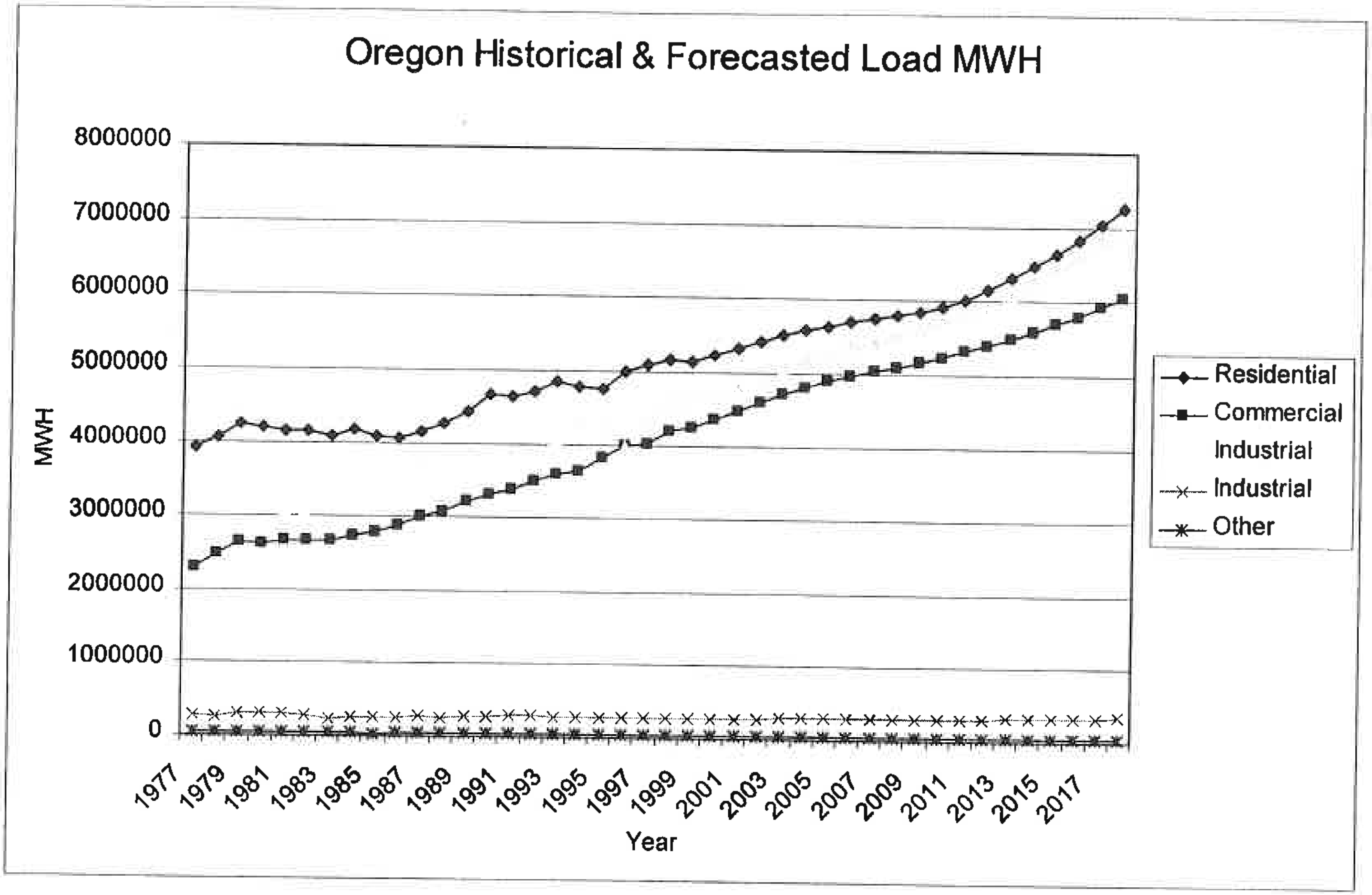
	Residential	Commercial	Industrial	Irrigation	Other
1979-1998	9.28%	9.26%	21.35%	-0.81%	6.45%
1999-2018	1.75%	0.04%	0.46%	0.00%	0.00%

Wyoming E

	Residential	Commercial	Industrial	Irrigation	Other
1979-1998	2.66%	3.32%	4.67%	0.64%	-2.83%
1999-2018	2.03%	2.38%	1.49%	0.43%	0.00%

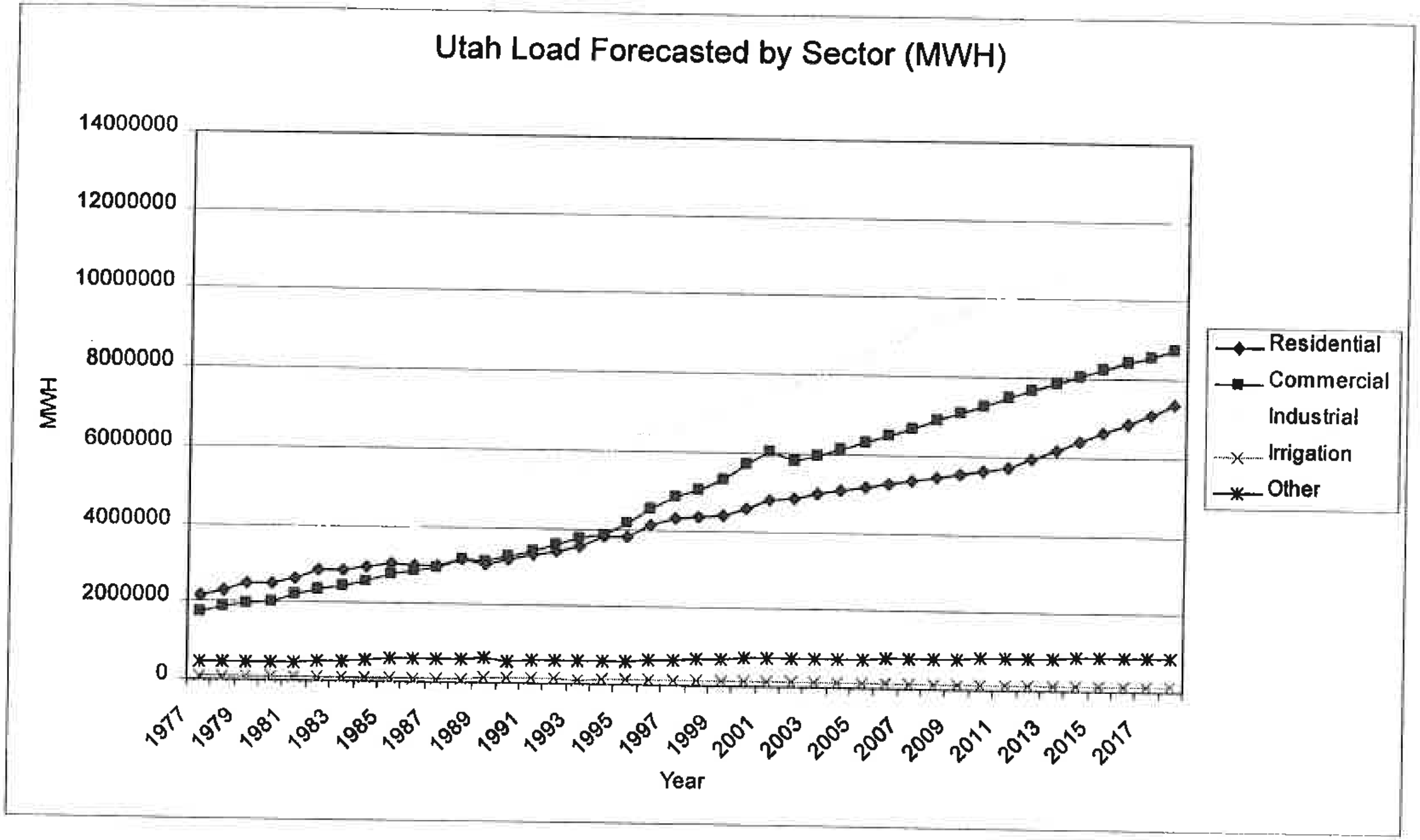

Idaho Load Forecasted by Sector (MWH)
2500000
2000000
1500000
1000000
500000
0
MWH
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
Year
Residential
Commercial
Industrial
Irrigation
Other

	Idaho									
	Residential		Commercial		Industrial		Irrigation		Other	
	MWH	% Change	MWH	% Change	MWH	% Change	MWH	% Change	MWH	% Change
1977	459602		130854		1375942		414336		3084	
1978	473536	2.99%	136689	4.46%	1435725	4.34%	395375	-4.58%	2979	-3.40%
1979	511266	7.97%	149251	9.19%	1582930	10.25%	412668	4.37%	3040	2.05%
1980	445945	-12.78%	139685	-6.41%	1590906	0.50%	334733	-18.89%	2600	-14.47%
1981	485805	8.94%	147764	5.78%	1585891	-0.32%	416820	24.52%	2826	8.69%
1982	499647	2.85%	156675	6.03%	1438717	-9.28%	387842	-6.95%	2115	-25.16%
1983	490485	-1.83%	156772	0.06%	1238168	-13.94%	334740	-13.69%	1731	-18.16%
1984	526316	7.31%	162090	3.39%	1317214	6.38%	298828	-10.73%	1740	0.52%
1985	527646	0.25%	172264	6.28%	1242878	-5.64%	402142	34.57%	1720	-1.15%
1986	499194	-5.39%	167356	-2.85%	1264426	1.73%	772945	92.21%	1663	-3.31%
1987	480808	-3.68%	162492	-2.91%	1495320	18.26%	395649	-48.81%	1734	4.27%
1988	511551	6.39%	178694	9.97%	1592650	6.51%	548533	38.64%	1762	1.61%
1989	517063	1.08%	174528	-2.33%	1628587	2.26%	489988	-10.67%	1767	0.28%
1990	527201	1.96%	179940	3.10%	1628660	0.00%	553587	12.98%	1695	-4.07%
1991	552903	4.88%	190018	5.60%	1661764	2.03%	482871	-12.77%	1810	6.78%
1992	544908	-1.45%	201661	6.13%	1627629	-2.05%	479810	-0.63%	1856	2.54%
1993	571975	4.97%	191165	-5.20%	1624010	-0.22%	449168	-6.39%	1891	1.89%
1994	554227	-3.10%	194196	1.59%	1555763	-4.20%	402855	-10.31%	1891	0.00%
1995	552955	-0.23%	224280	15.49%	1651607	6.16%	413753	2.71%	1891	0.00%
1996	571400	3.34%	240986	7.45%	1490357	-9.76%	403012	-2.60%	1891	0.00%
1997	581470	1.76%	262553	8.95%	1509525	1.29%	407458	1.10%	1891	0.00%
1998	546670	-5.98%	266721	1.59%	1586422	5.09%	411463	0.98%	1891	0.00%
1999	595938	9.01%	261549	-1.94%	1621993	2.24%	418293	1.66%	1891	0.00%
2000	612816	2.83%	271905	3.96%	1647012	1.54%	422700	1.05%	1891	0.00%
2001	627479	2.39%	281298	3.45%	1678110	1.89%	427304	1.09%	1891	0.00%
2002	639289	1.88%	290723	3.35%	1707334	1.74%	431472	0.98%	1891	0.00%
2003	651321	1.88%	300477	3.36%	1734288	1.58%	435459	0.92%	1891	0.00%
2004	658604	1.12%	310231	3.25%	1758231	1.38%	436352	0.21%	1891	0.00%
2005	668084	1.44%	316470	2.01%	1783123	1.42%	439614	0.75%	1891	0.00%
2006	678195	1.51%	323109	2.10%	1807804	1.38%	442918	0.75%	1891	0.00%
2007	688750	1.56%	329880	2.10%	1840123	1.79%	446851	0.89%	1891	0.00%
2008	699308	1.53%	336131	1.89%	1861762	1.18%	449866	0.67%	1891	0.00%
2009	710663	1.62%	342692	1.95%	1898569	1.98%	454138	0.95%	1891	0.00%
2010	723289	1.78%	349168	1.89%	1905361	0.36%	456127	0.44%	1891	0.00%
2011	739537	2.25%	355513	1.82%	1928047	1.19%	459606	0.76%	1891	0.00%
2012	763343	3.22%	361810	1.77%	1953555	1.32%	463852	0.92%	1891	0.00%
2013	788430	3.29%	368250	1.78%	1978721	1.29%	468140	0.92%	1891	0.00%
2014	814933	3.36%	375176	1.88%	2008140	1.49%	472852	1.01%	1891	0.00%
2015	843811	3.54%	382337	1.91%	2032422	1.21%	477327	0.95%	1891	0.00%
2016	873360	3.50%	388676	1.66%	2056798	1.20%	481753	0.93%	1891	0.00%
2017	913339	4.58%	394708	1.55%	2080142	1.13%	486803	1.05%	1891	0.00%
2018	942786	3.22%	400630	1.50%	2104264	1.16%	491081	0.88%	1891	0.00%



Oregon Historical & Forecasted Load MWH
8000000
7000000
6000000
5000000
4000000
3000000
2000000
1000000
0
MWH
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
Year
Residential
Commercial
Industrial
Industrial
Other

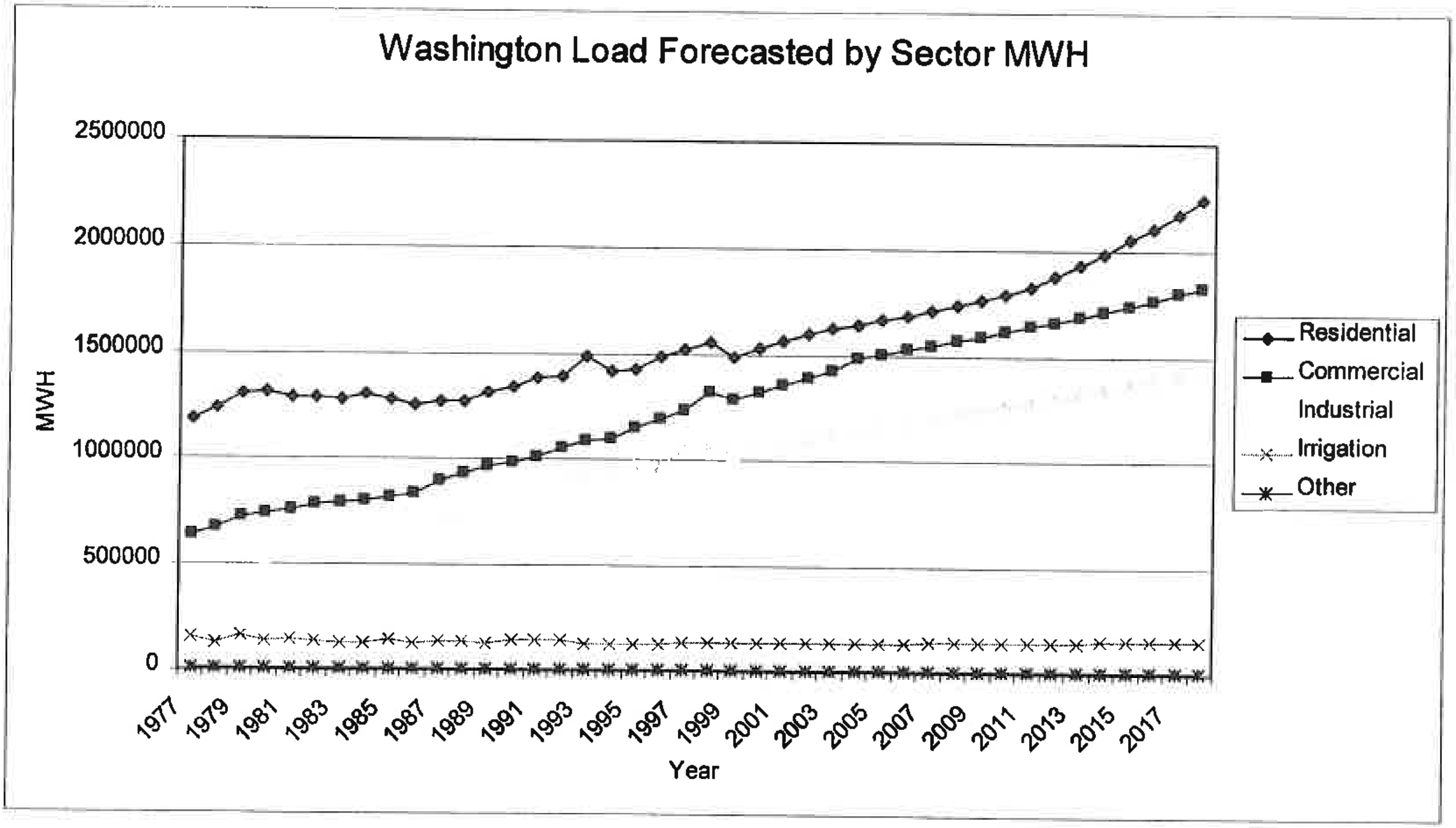
	Oregon									
	Residential		Commercial		Industrial		Irrigation		Other	
1977	3926643		2291045		3262655		286285		43078	
1978	4067842	3.60%	2476440	8.09%	3220260	-1.30%	248017	-13.37%	45440	5.48%
1979	4242292	4.29%	2639373	6.58%	3328724	3.37%	315152	27.07%	45530	0.20%
1980	4188277	-1.27%	2637587	-0.07%	3156030	-5.19%	295226	-6.32%	46894	3.00%
1981	4150282	-0.91%	2682631	1.71%	3071228	-2.69%	299446	1.43%	45075	-3.88%
1982	4157876	0.18%	2666134	-0.61%	2970939	-3.27%	273530	-8.65%	43000	-4.60%
1983	4082581	-1.81%	2672071	0.22%	3246346	9.27%	236458	-13.55%	42000	-2.33%
1984	4178640	2.35%	2750453	2.93%	3408377	4.99%	250657	6.00%	39370	-6.26%
1985	4073989	-2.50%	2803304	1.92%	3477377	2.02%	263708	5.21%	33889	-13.92%
1986	4048076	-0.64%	2879471	2.72%	3573734	2.77%	259068	-1.76%	44064	30.02%
1987	4147117	2.45%	3007818	4.46%	3750712	4.95%	278057	7.33%	44525	1.05%
1988	4258154	2.68%	3072837	2.16%	3860675	2.93%	252677	-9.13%	42614	-4.29%
1989	4430988	4.06%	3216642	4.68%	3881342	0.54%	270612	7.10%	44244	3.83%
1990	4665497	5.29%	3300723	2.61%	3866880	-0.37%	284910	5.28%	44515	0.61%
1991	4638968	-0.57%	3385150	2.56%	3819104	-1.24%	298968	4.93%	44765	0.56%
1992	4712943	1.59%	3486317	2.99%	3869943	1.33%	301820	0.95%	44920	0.35%
1993	4848834	2.88%	3588192	2.92%	4053690	4.75%	285672	-5.35%	48209	7.32%
1994	4789282	-1.23%	3636736	1.35%	4306381	6.23%	270075	-5.46%	48190	-0.04%
1995	4758051	-0.65%	3816268	4.94%	4217469	-2.06%	270705	0.23%	49402	2.52%
1996	5000147	5.09%	3996740	4.73%	3983640	-5.54%	272702	0.74%	50710	2.65%
1997	5080239	1.60%	4008777	0.30%	4265498	7.08%	276631	1.44%	51958	2.46%
1998	5161358	1.60%	4210255	5.03%	4568915	7.11%	282700	2.19%	51958	0.00%
1999	5129755	-0.61%	4251850	0.99%	4630997	1.36%	283431	0.26%	51958	0.00%
2000	5224127	1.84%	4362197	2.60%	4644859	0.30%	285642	0.78%	51958	0.00%
2001	5320196	1.84%	4475301	2.59%	4759478	2.47%	288891	1.14%	51958	0.00%
2002	5417993	1.84%	4591233	2.59%	4878360	2.50%	292192	1.14%	51958	0.00%
2003	5517550	1.84%	4710063	2.59%	5025957	3.03%	295784	1.23%	51958	0.00%
2004	5572595	1.00%	4810817	2.14%	5149841	2.46%	297960	0.74%	51958	0.00%
2005	5636812	1.15%	4891636	1.68%	5261775	2.17%	300423	0.83%	51958	0.00%
2006	5692471	0.99%	4965535	1.51%	5346958	1.62%	302465	0.68%	51958	0.00%
2007	5744352	0.91%	5034220	1.38%	5401223	1.01%	304115	0.55%	51958	0.00%
2008	5796457	0.91%	5099177	1.29%	5485152	1.55%	306004	0.62%	51958	0.00%
2009	5850613	0.93%	5166999	1.33%	5603077	2.15%	308245	0.73%	51958	0.00%
2010	5914316	1.09%	5242548	1.46%	5707757	1.87%	310508	0.73%	51958	0.00%
2011	6005127	1.54%	5320560	1.49%	5815381	1.89%	313054	0.82%	51958	0.00%
2012	6147916	2.38%	5399508	1.48%	5922509	1.84%	316060	0.96%	51958	0.00%
2013	6300812	2.49%	5486638	1.61%	6054924	2.24%	319432	1.07%	51958	0.00%
2014	6463654	2.59%	5587070	1.83%	6220557	2.74%	323277	1.20%	51958	0.00%
2015	6644685	2.80%	5695737	1.94%	6414836	3.12%	327561	1.33%	51958	0.00%
2016	6833568	2.84%	5805708	1.93%	6602334	2.92%	331813	1.30%	51958	0.00%
2017	7038760	3.00%	5927551	2.10%	6797422	2.95%	336319	1.36%	51958	0.00%
2018	7252167	3.03%	6048203	2.04%	6978237	2.66%	340703	1.30%	51958	0.00%



Utah Load Forecasted by Sector (MWH)
14000000
12000000
10000000
8000000
6000000
4000000
2000000
0
MWH
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
Year
Residential
Commercial
Industrial
Irrigation
Other

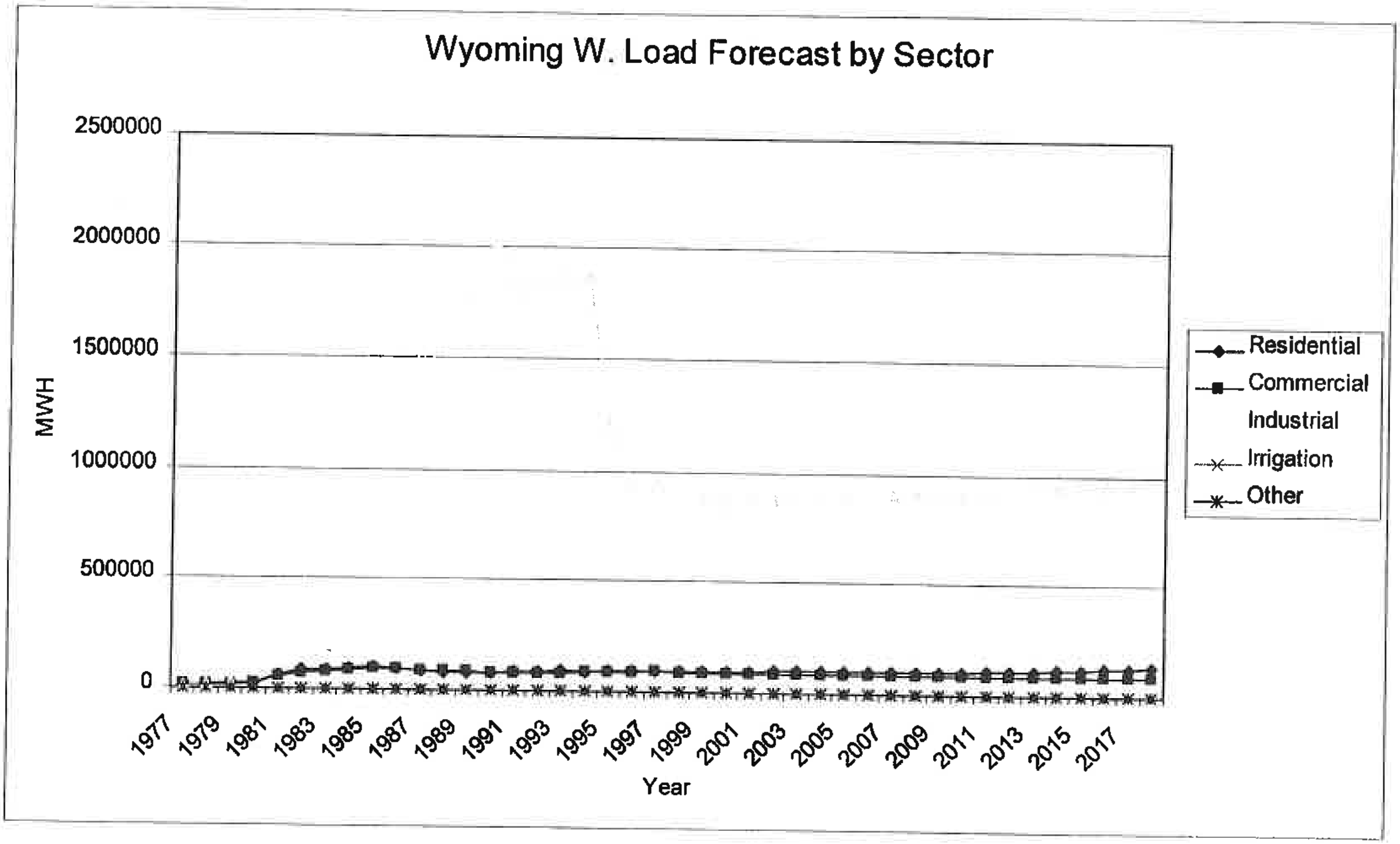
Utah

	Residential		Commercial		Industrial		Irrigation		Other	
	MWH	% Change	MWH	% Change	MWH	% Change	MWH	% Change	MWH	% Change
1977	2161971		1758948		2499091		109830		439825	
1978	2276440	5.29%	1866945	6.14%	3167512	26.75%	96123	-12.48%	443067	0.74%
1979	2473004	8.63%	1988627	6.52%	3464743	9.38%	102274	6.40%	454877	2.67%
1980	2458239	-0.60%	2007972	0.97%	3695490	6.66%	79447	-22.32%	465205	2.27%
1981	2590943	5.40%	2173538	8.25%	3887597	5.20%	97714	22.99%	475533	2.22%
1982	2825497	9.05%	2323415	6.90%	3881544	-0.16%	105980	8.46%	500148	5.18%
1983	2849971	0.87%	2443062	5.15%	4172659	7.50%	82511	-22.14%	516148	3.20%
1984	2941982	3.23%	2583886	5.76%	4371729	4.77%	76991	-6.69%	543833	5.36%
1985	3000563	1.99%	2726181	5.51%	4196804	-4.00%	103548	34.49%	578761	6.42%
1986	2996563	-0.13%	2827924	3.73%	4089377	-2.56%	85611	-17.32%	585976	1.25%
1987	2995711	-0.03%	2946138	4.18%	4287902	4.85%	86937	1.55%	593054	1.21%
1988	3153390	5.26%	3152606	7.01%	4795609	11.84%	88399	1.68%	585668	-1.25%
1989	3040006	-3.60%	3110606	-1.33%	5097778	6.30%	117193	32.57%	628337	7.29%
1990	3170912	4.31%	3231149	3.88%	5208464	2.17%	143129	22.13%	570398	-9.22%
1991	3304175	4.20%	3399600	5.21%	5343775	2.60%	125541	-12.29%	576363	1.05%
1992	3364014	1.81%	3574568	5.15%	5781993	8.20%	127034	1.19%	591054	2.55%
1993	3528238	4.88%	3748976	4.88%	5686899	-1.64%	112810	-11.20%	599911	1.50%
1994	3776546	7.04%	3852463	2.76%	5865359	3.14%	118858	5.36%	594006	-0.98%
1995	3778038	0.04%	4147440	7.66%	6369599	8.60%	120621	1.48%	614959	3.53%
1996	4137734	9.52%	4508953	8.72%	6474327	1.64%	128481	6.52%	639864	4.05%
1997	4279331	3.42%	4840806	7.36%	6586722	1.74%	124759	-2.90%	661831	3.43%
1998	4340028	1.42%	5033571	3.98%	6934371	5.28%	125648	0.71%	674063	1.85%
1999	4396043	1.29%	5327907	5.85%	7088931	2.23%	126510	0.69%	692383	2.72%
2000	4582901	4.25%	5706406	7.10%	7362545	3.86%	127991	1.17%	715289	3.31%
2001	4790212	4.52%	6051347	6.04%	7568994	2.80%	129272	1.00%	735473	2.82%
2002	4847560	1.20%	5793381	-4.26%	7732575	2.16%	129154	-0.09%	720809	-1.99%
2003	4971659	2.56%	5956437	2.81%	7903788	2.21%	129903	0.58%	730284	1.31%
2004	5060306	1.78%	6140758	3.09%	8218027	3.98%	130822	0.71%	741076	1.48%
2005	5155690	1.88%	6328811	3.06%	8503095	3.47%	131784	0.73%	752250	1.51%
2006	5246137	1.75%	6511157	2.88%	8771466	3.16%	132600	0.62%	763080	1.44%
2007	5335912	1.71%	6693876	2.81%	9055083	3.23%	133424	0.62%	774175	1.45%
2008	5433534	1.83%	6889317	2.92%	9336900	3.11%	134234	0.61%	785550	1.47%
2009	5525402	1.69%	7087317	2.87%	9644177	3.29%	135067	0.62%	796183	1.35%
2010	5618381	1.68%	7287218	2.82%	9860023	2.24%	135801	0.54%	807963	1.48%
2011	5727960	1.95%	7484179	2.70%	10137654	2.82%	136626	0.61%	818865	1.35%
2012	5952353	3.92%	7682874	2.65%	10352954	2.12%	137518	0.65%	829748	1.33%
2013	6180319	3.83%	7877354	2.53%	10534339	1.75%	138334	0.59%	840039	1.24%
2014	6403429	3.61%	8061440	2.34%	10785858	2.39%	139210	0.63%	849492	1.13%
2015	6637024	3.65%	8238723	2.20%	10979571	1.80%	139961	0.54%	857722	0.97%
2016	6877886	3.63%	8412116	2.10%	11202703	2.03%	140786	0.59%	867490	1.14%
2017	7089703	3.08%	8551258	1.65%	11548065	3.08%	141660	0.62%	874914	0.86%
2018	7379075	4.08%	8744772	2.26%	12136303	5.09%	143039	0.97%	885507	1.21%



Washington Load Forecasted by Sector MWH
MWH
2500000
2000000
1500000
1000000
500000
0
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
Year
Residential
Commercial
Industrial
Irrigation
Other

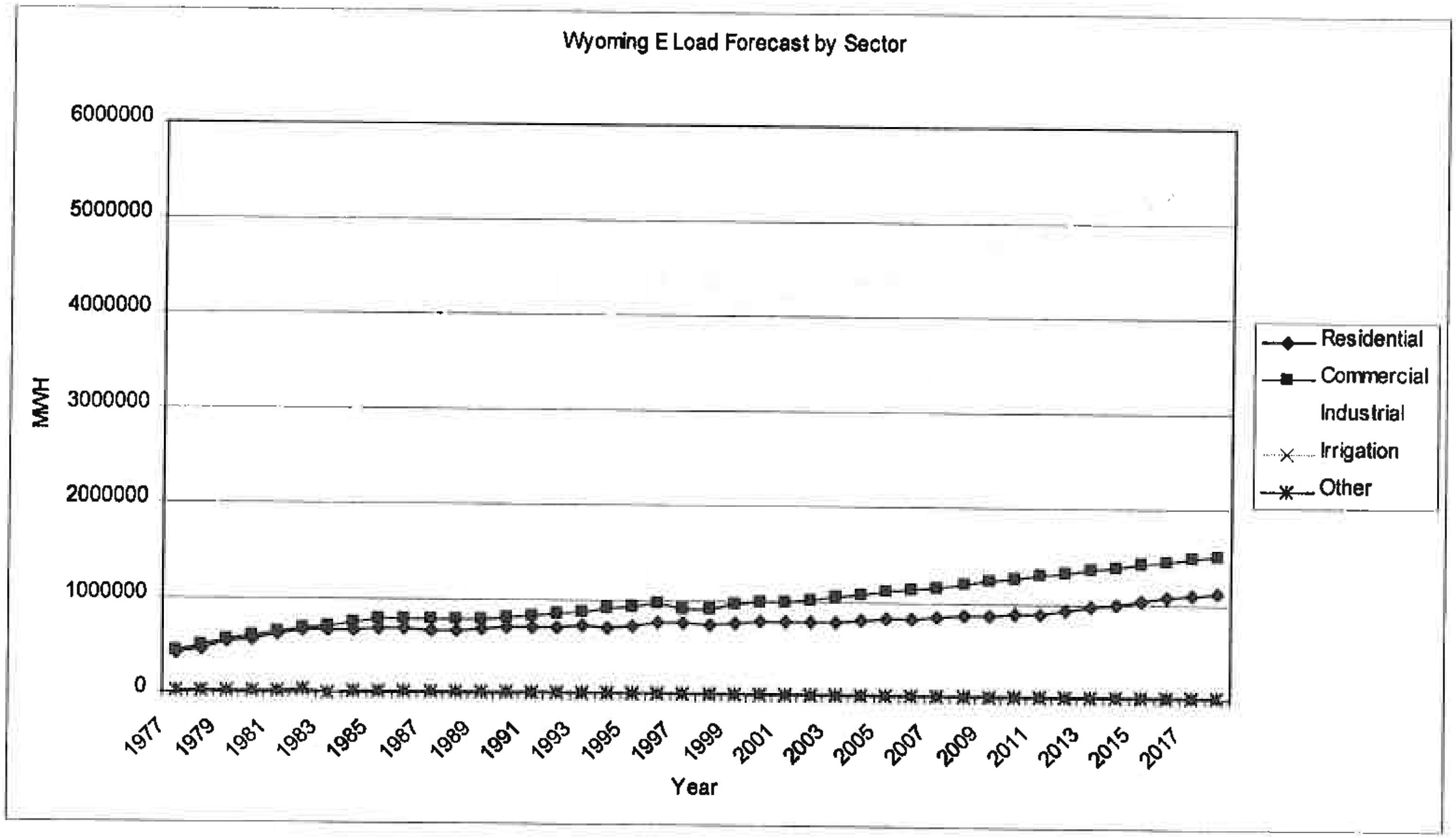
Washington										
	Residential		Commercial		Industrial		Irrigation		Other	
	MWH	% Change	MWH	% Change	MWH	% Change	MWH	% Change	MWH	% Change
1977	1188256		644030		400324		154024		10060	
1978	1236601	3.98%	677929	5.26%	342924	-14.34%	125905	-18.26%	10139	0.79%
1979	1305887	5.69%	727046	7.25%	414120	20.76%	161997	28.67%	10323	1.81%
1980	1316281	0.80%	741243	1.95%	523813	26.49%	142590	-11.98%	10299	-0.23%
1981	1289152	-2.06%	757373	2.18%	574637	9.70%	150574	5.60%	9605	-6.74%
1982	1292298	0.24%	783786	3.49%	552212	-3.90%	139774	-7.17%	12602	31.20%
1983	1281388	-0.84%	793256	1.21%	608630	10.22%	128902	-7.78%	9000	-28.58%
1984	1302399	1.64%	808813	1.96%	668038	9.76%	130242	1.04%	7460	-17.11%
1985	1279094	-1.79%	824016	1.88%	698048	4.49%	147737	13.43%	7437	-0.31%
1986	1252312	-2.09%	836993	1.57%	723184	3.60%	131538	-10.96%	7511	1.00%
1987	1268959	1.33%	899829	7.51%	734292	1.54%	139234	5.85%	7407	-1.38%
1988	1275644	0.53%	930617	3.42%	747853	1.85%	138323	-0.65%	7494	1.17%
1989	1310918	2.77%	972875	4.54%	777008	3.90%	133393	-3.56%	7437	-0.76%
1990	1343618	2.49%	983375	1.08%	798970	2.83%	146201	9.60%	7609	2.31%
1991	1380151	2.72%	1011702	2.88%	833544	4.33%	144686	-1.04%	7434	-2.30%
1992	1396151	1.16%	1057030	4.48%	932160	11.83%	148273	2.48%	7791	4.80%
1993	1483702	6.27%	1089916	3.11%	941591	1.01%	131868	-11.06%	8143	4.52%
1994	1418211	-4.41%	1101331	1.05%	959140	1.86%	128387	-2.64%	8198	0.68%
1995	1428595	0.73%	1152292	4.63%	979326	2.10%	129892	1.17%	8198	0.00%
1996	1485027	3.95%	1194143	3.63%	977317	-0.21%	131648	1.35%	8222	0.29%
1997	1518970	2.29%	1236836	3.58%	1044718	6.90%	134241	1.97%	8222	0.00%
1998	1556143	2.45%	1321338	6.83%	1076942	3.08%	136959	2.02%	8222	0.00%
1999	1491334	-4.16%	1293219	-2.13%	1030757	-4.29%	134550	-1.76%	8222	0.00%
2000	1529424	2.55%	1327480	2.65%	1049326	1.80%	136153	1.19%	8222	0.00%
2001	1568442	2.55%	1361005	2.53%	1067410	1.72%	137732	1.16%	8222	0.00%
2002	1596840	1.81%	1393670	2.40%	1089899	2.11%	139172	1.05%	8222	0.00%
2003	1625719	1.81%	1427119	2.40%	1112786	2.10%	140625	1.04%	8222	0.00%
2004	1644628	1.16%	1485939	4.12%	1134858	1.98%	139990	-0.45%	8222	0.00%
2005	1666132	1.31%	1507630	1.46%	1157455	1.99%	141072	0.77%	8222	0.00%
2006	1689428	1.40%	1529088	1.42%	1180698	2.01%	142183	0.79%	8222	0.00%
2007	1713272	1.41%	1550639	1.41%	1204383	2.01%	143304	0.79%	8222	0.00%
2008	1736152	1.34%	1571590	1.35%	1228102	1.97%	144393	0.76%	8222	0.00%
2009	1761609	1.47%	1593304	1.38%	1245984	1.46%	145431	0.72%	8222	0.00%
2010	1789193	1.57%	1616538	1.46%	1264461	1.48%	146529	0.76%	8222	0.00%
2011	1825704	2.04%	1639593	1.43%	1286450	1.74%	147819	0.88%	8222	0.00%
2012	1876118	2.76%	1662383	1.39%	1304931	1.44%	149260	0.97%	8222	0.00%
2013	1930379	2.89%	1686066	1.42%	1321337	1.26%	150732	0.99%	8222	0.00%
2014	1984513	2.80%	1712481	1.57%	1345674	1.84%	152344	1.07%	8222	0.00%
2015	2046003	3.10%	1739901	1.60%	1368827	1.72%	154054	1.12%	8222	0.00%
2016	2106270	2.95%	1767895	1.61%	1391867	1.68%	155732	1.09%	8222	0.00%
2017	2171777	3.11%	1797684	1.69%	1420550	2.06%	157582	1.19%	8222	0.00%
2018	2237134	3.01%	1825436	1.54%	1448511	1.97%	159371	1.13%	8222	0.00%



Wyoming W. Load Forecast by Sector
2500000
2000000
1500000
1000000
500000
0
MWH
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
Year
Residential
Commercial
Industrial
Irrigation
Other

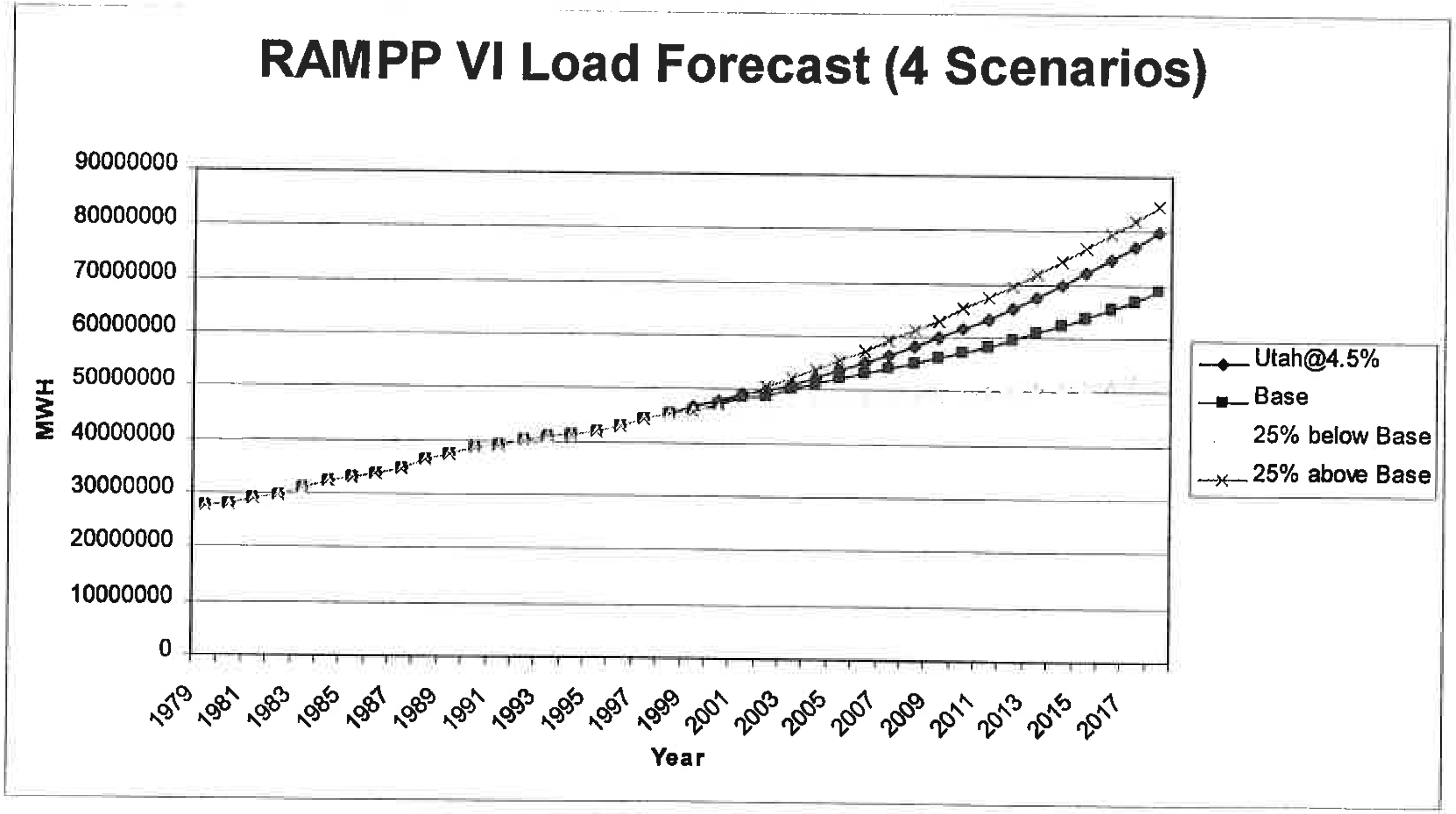
Wyoming W.

	Residential		Commercial		Industrial		Irrigation		Other	
	MWH	% Change	MWH	% Change	MWH	% Change	MWH	% Change	MWH	% Change
1977	15617		15766		18979		1554		478	
1978	17598	12.68%	17283	9.62%	23726	25.01%	1695	9.07%	476	-0.42%
1979	21080	19.79%	18972	9.77%	35679	50.38%	1916	13.04%	483	1.47%
1980	24266	15.11%	20331	7.16%	83559	134.20%	2120	10.65%	497	2.90%
1981	67177	176.84%	52256	157.03%	291919	249.36%	2324	9.62%	3117	527.16%
1982	89172	32.74%	73363	40.39%	440026	50.74%	1703	-26.72%	1211	-61.15%
1983	91318	2.41%	77647	5.84%	1089457	147.59%	1445	-15.15%	1276	5.37%
1984	98164	7.50%	84136	8.36%	1341348	23.12%	1616	11.83%	1496	17.24%
1985	103255	5.19%	98404	16.96%	1603187	19.52%	2246	38.99%	1517	1.40%
1986	99107	-4.02%	94490	-3.98%	1566827	-2.27%	1820	-18.97%	1560	2.83%
1987	85463	-13.77%	87628	-7.26%	1475859	-5.81%	1696	-6.81%	1364	-12.56%
1988	82428	-3.55%	86138	-1.70%	1544576	4.66%	2162	27.48%	1712	25.51%
1989	83082	0.79%	84779	-1.58%	1787518	15.73%	2240	3.61%	1524	-10.98%
1990	82718	-0.44%	81509	-3.86%	2012213	12.57%	2345	4.69%	1405	-7.81%
1991	89426	8.11%	81633	0.15%	1821595	-9.47%	2023	-13.73%	1512	7.62%
1992	87172	-2.52%	80516	-1.37%	1801647	-1.10%	2023	0.00%	1505	-0.46%
1993	92954	6.63%	82332	2.26%	1863622	3.44%	1834	-9.34%	1562	3.79%
1994	91290	-1.79%	83893	1.90%	1858669	-0.27%	1451	-20.88%	1562	0.00%
1995	93694	2.63%	86267	2.83%	1179425	-36.54%	1451	0.00%	1562	0.00%
1996	94034	0.36%	88887	3.04%	936817	-20.57%	1451	0.00%	1562	0.00%
1997	94933	0.96%	92962	4.58%	937320	0.05%	1451	0.00%	1562	0.00%
1998	95873	0.99%	88559	-4.74%	937532	0.02%	1451	0.00%	1562	0.00%
1999	96674	0.84%	88767	0.23%	882580	-5.86%	1451	0.00%	1562	0.00%
2000	97736	1.10%	88986	0.25%	864201	-2.08%	1451	0.00%	1562	0.00%
2001	96748	-1.01%	89230	0.27%	866930	0.32%	1451	0.00%	1562	0.00%
2002	100526	3.90%	90213	1.10%	880339	1.55%	1451	0.00%	1562	0.00%
2003	102336	1.80%	91206	1.10%	893982	1.55%	1451	0.00%	1562	0.00%
2004	102320	-0.02%	91733	0.58%	897128	0.35%	1451	0.00%	1562	0.00%
2005	102661	0.33%	91531	-0.22%	899100	0.22%	1451	0.00%	1562	0.00%
2006	103172	0.50%	91470	-0.07%	902322	0.36%	1451	0.00%	1562	0.00%
2007	103776	0.58%	91337	-0.15%	903182	0.10%	1451	0.00%	1562	0.00%
2008	104567	0.76%	91078	-0.28%	902158	-0.11%	1451	0.00%	1562	0.00%
2009	105567	0.96%	90815	-0.29%	902177	0.00%	1451	0.00%	1562	0.00%
2010	106763	1.13%	90470	-0.38%	902128	-0.01%	1451	0.00%	1562	0.00%
2011	108651	1.77%	90198	-0.30%	910170	0.89%	1451	0.00%	1562	0.00%
2012	111631	2.74%	90042	-0.17%	925198	1.65%	1451	0.00%	1562	0.00%
2013	114799	2.84%	89845	-0.22%	934627	1.02%	1451	0.00%	1562	0.00%
2014	118189	2.95%	89755	-0.10%	943501	0.95%	1451	0.00%	1562	0.00%
2015	121500	2.80%	89453	-0.34%	956034	1.33%	1451	0.00%	1562	0.00%
2016	125528	3.32%	89150	-0.34%	953864	-0.23%	1451	0.00%	1562	0.00%
2017	129305	3.01%	88959	-0.21%	959023	0.54%	1451	0.00%	1562	0.00%
2018	134367	3.91%	89490	0.60%	963612	0.48%	1451	0.00%	1562	0.00%


Wyoming E Load Forecast by Sector
MWH
6000000
5000000
4000000
3000000
2000000
1000000
0
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
Year
Residential
Commercial
Industrial
Irrigation
Other

Wyoming E

	Residential		Commercial		Industrial		Irrigation		Other	
	MWH	% Change	MWH	% Change	MWH	% Change	MWH	% Change	MWH	% Change
1977	416850		436003		1710503		10771		18696	
1978	460706	10.52%	491860	12.81%	1869273	9.28%	8122	-24.59%	19385	3.69%
1979	526522	14.29%	553676	12.57%	2087209	11.66%	10556	29.97%	22320	15.14%
1980	566605	7.61%	591015	6.74%	2309384	10.64%	12205	15.62%	23138	3.66%
1981	608405	7.38%	642611	8.73%	2543451	10.14%	12067	-1.13%	21510	-7.04%
1982	655592	7.76%	677691	5.46%	2713351	6.68%	11377	-5.72%	33047	53.64%
1983	657119	0.23%	698072	3.01%	2867856	5.69%	9893	-13.04%	5824	-82.38%
1984	666935	1.49%	741013	6.15%	3001896	4.67%	10838	9.55%	25590	339.39%
1985	672278	0.80%	776680	4.81%	3137718	4.52%	13483	24.40%	26205	2.40%
1986	674971	0.40%	783408	0.87%	3275846	4.40%	13378	-0.78%	27418	4.63%
1987	657763	-2.55%	780432	-0.38%	3927902	19.90%	11791	-11.86%	22036	-19.63%
1988	667738	1.52%	788287	1.01%	4107631	4.58%	14341	21.63%	12659	-42.55%
1989	677376	1.44%	789528	0.16%	4239233	3.20%	13883	-3.19%	11448	-9.57%
1990	696860	2.88%	810802	2.69%	4401523	3.83%	11422	-17.73%	11304	-1.26%
1991	701023	0.60%	834226	2.89%	4353266	-1.10%	8668	-24.11%	11321	0.15%
1992	704216	0.46%	848762	1.74%	4282387	-1.63%	8648	-0.23%	11302	-0.17%
1993	722584	2.61%	864214	1.82%	4183180	-2.32%	8744	1.10%	11238	-0.57%
1994	710251	-1.71%	906402	4.88%	4013897	-4.05%	8975	2.64%	11238	0.00%
1995	726209	2.25%	931098	2.72%	4077158	1.58%	9016	0.46%	11238	0.00%
1996	758769	4.48%	965720	3.72%	4403576	8.01%	9171	1.72%	11238	0.00%
1997	758955	0.02%	914377	-5.32%	4448061	1.01%	9168	-0.03%	11238	0.00%
1998	748185	-1.42%	913941	-0.05%	4344676	-2.32%	9125	-0.47%	11238	0.00%
1999	766186	2.41%	968230	5.94%	4110850	-5.38%	9064	-0.67%	11238	0.00%
2000	775555	1.22%	979675	1.18%	4181303	1.71%	9099	0.39%	11238	0.00%
2001	785099	1.23%	993268	1.39%	4196858	0.37%	9114	0.16%	11238	0.00%
2002	789125	0.51%	1018850	2.58%	4260054	1.51%	9150	0.39%	11238	0.00%
2003	793171	0.51%	1045071	2.57%	4323579	1.49%	9185	0.39%	11238	0.00%
2004	804345	1.41%	1076502	3.01%	4356649	0.76%	9214	0.32%	11238	0.00%
2005	816168	1.47%	1104818	2.63%	4436807	1.84%	9259	0.48%	11238	0.00%
2006	829218	1.60%	1134469	2.68%	4509300	1.63%	9301	0.45%	11238	0.00%
2007	842828	1.64%	1164756	2.67%	4576929	1.50%	9341	0.43%	11238	0.00%
2008	857917	1.79%	1195519	2.64%	4644327	1.47%	9381	0.43%	11238	0.00%
2009	873468	1.81%	1226818	2.62%	4716926	1.56%	9423	0.45%	11238	0.00%
2010	876397	0.34%	1258391	2.57%	4818755	2.16%	9470	0.50%	11238	0.00%
2011	896178	2.26%	1290125	2.52%	4898857	1.66%	9515	0.47%	11238	0.00%
2012	928585	3.62%	1321732	2.45%	4991351	1.89%	9567	0.55%	11238	0.00%
2013	961473	3.54%	1354273	2.46%	5089241	1.96%	9621	0.56%	11238	0.00%
2014	993223	3.30%	1385669	2.32%	5145771	1.11%	9660	0.40%	11238	0.00%
2015	1034068	4.11%	1417028	2.26%	5210630	1.26%	9704	0.46%	11238	0.00%
2016	1068365	3.32%	1447737	2.17%	5283997	1.41%	9748	0.45%	11238	0.00%
2017	1095811	2.57%	1478994	2.16%	5359387	1.43%	9790	0.43%	11238	0.00%
2018	1121761	2.37%	1514295	2.39%	5444137	1.58%	9835	0.46%	11238	0.00%


RAMPP VI Load Forecast (4 Scenarios)
MWH
90000000
80000000
70000000
60000000
50000000
40000000
30000000
20000000
10000000
0
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
Year
Utah@4.5%
Base
25% below Base
25% above Base

Four Load Forecast Scenarios

	Utah@4.5%	Base	25% below	25% above
1979	27611557	27611557	27611557	27611557
1980	27911582	27911582	27911582	27911582
1981	29139271	29139271	29139271	29139271
1982	29710264	29710264	29710264	29710264
1983	30886786	30886786	30886786	30886786
1984	32342090	32342090	32342090	32342090
1985	32996079	32996079	32996079	32996079
1986	33585811	33585811	33585811	33585811
1987	34775629	34775629	34775629	34775629
1988	36503422	36503422	36503422	36503422
1989	37541923	37541923	37541923	37541923
1990	38769534	38769534	38769534	38769534
1991	39107985	39107985	39107985	39107985
1992	40080055	40080055	40080055	40080055
1993	40827121	40827121	40827121	40827121
1994	41269722	41269722	41269722	41269722
1995	41802460	41802460	41802460	41802460
1996	42968524	42968524	42968524	42968524
1997	44152464	44152464	44152464	44152464
1998	45447781	45447781	45447781	45447781
1999	46545082	45774113	46187444	45754781
2000	47866186	47081651	46477270	47230373
2001	49178678	48381514	46768915	48753552
2002	49729995	48916235	47062390	50362420
2003	50834880	50004071	47357707	52024380
2004	52272785	51105250	47654876	53741184
2005	53747014	52178520	47953911	55514643
2006	55222623	53180866	48254821	57346626
2007	56709212	54162052	48557620	59239065
2008	58257850	55174899	48862319	61193954
2009	59919694	56270985	49168930	63213355
2010	61631059	57273877	49477466	65299395
2011	63472588	58421692	49787937	67454275
2012	65486358	59731121	50100356	69680266
2013	67611307	61054449	50414736	71979715
2014	69832557	62462391	50731088	74355046
2015	72204071	63895241	51049426	76808762
2016	74637558	65351469	51369761	79343452
2017	77208947	66925827	51692106	81961785
2018	79852108	68871038	52016474	84666524

PacifiCorp

Integrated Resource Planning

Existing Resources and Wholesale Transactions

RAMPP-6

May 7, 1999

Changes to the RAMPP Model

Existing Resources	
Thermal plants	Thermal levels and life adjusted to be consistent with Engineering Estimates
BPA Peaking	Reduced BPA Peaking contract amounts
BPA Supp Capacity	Updated to more accurately reflect actual purchases
Hydro Pacific	Updated to Pacific NW Coordination Agreement levels
Mid Columbia	Updated to Pacific NW Coordination Agreement levels
T&D Eff	Historical T&D efficiencies will be included in the new load forecast
Wind Foote Creek	Foote Creak at full output offset by a new BPA Wind Sale
Purchase	
Deseret Annual	Updated to more accurately reflect actual purchases
BPA South Oregon	Contract expired in 1998
Sales	
APPA	Contract revision in April 1998; Contract extended
Azusa	Contract expired in 1998
Black Hills Load	Contract revision in September 1997
BPA Wind Sale	New Contract
Canadian Entitlement	Updated to more accurately reflect actual sales
Citizens Power	New Contract
Clark County PUD	Updated to more accurately reflect actual sales
Clark-FW	New Contract
Clark-WT	New Contract
Cowlitz BHP	Corrected contract end date, Expires April 30, 2002
ESI Kaiser	Contract expired in 1999
Glenbrook	Contract expired in 1998
Green Mountain	New Contract
Hinson	Contract revision in February 1998, Expires Dec 2000
Hurricane Net Sale	New Contract
Montana Sell Back	New Contract
Nevada 1	Contract expired in 1999
Pan Energy	Contract expired in 1998
PECO	Contract expired in 1998
Sierra Pacific 1	Contract terminated by Sierra effective April 30, 2000
UMPA 1	Corrected contract end date, Expires June 2005

RAMPP-6 Less RAMPP-5
Summer Capacity (MW)

R-6 R-5	2000 2000	2001 2001	2002 2002	2003 2003	2004 2004	2005 2005	2006 2006	2007 2007	2014 2012	2019 201[illegible]	2029 202[illegible]
Thermal Plants											
Carbon 1,2	-	-	-	-	-	-	-	-	-	-	-
Centralia 1,2	-	-	-	-	-	-	-	(175)	(175)	(175)	(175)
Cholla 4	-	-	-	-	-	-	-	-	(637)	(637)	(637)
Colstrip 3,4	4	4	4	4	4	-	-	-	-	-	(380)
Craig 1,2	-	-	-	-	-	4	4	4	4	4	(140)
Dave Johnstn 1,2,3,4	(8)	(8)	(8)	(8)	-	-	-	-	-	-	(165)
Gadsby 1,2,3	-	-	-	-	(8)	(8)	(8)	(8)	(8)	(780)	(780)
Hayden 1,2	-	-	-	-	(235)	(235)	(235)	(235)	(235)	(235)	(235)
Hermiston	-	-	-	-	-	-	-	-	-	-	(78)
Hunter 1,2,3	2	2	2	2	2	-	-	-	-	-	-
Huntington 1,2	(27)	(27)	(27)	(27)	(27)	2	2	2	2	2	(1,120)
James River	2	2	2	2	2	(27)	(27)	(27)	(27)	(922)	(922)
Jim Bridger 1,2,3,4	2	2	2	2	2	2	2	2	2	(50)	(50)
Naughton 1,2,3	-	-	-	-	-	2	2	2	2	(1,411)	(1,411)
Wyodak	-	-	(8)	(8)	(8)	-	-	-	(700)	(700)	(700)
Total Thermal	(25)	(25)	(33)	(33)	(268)	(8)	(8)	(8)	(8)	(276)	(276)
						(268)	(268)	(443)	(1,780)	(5,180)	(7,069)
Renewables											
Blundell Geothermal	-	-	-	-	-	-	-	-	-	-	(23)
BPA Peaking	-	-	-	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)
BPA Supp Capacity	4	5	4	-	-	-	-	-	-	-	-
Hydro Idaho	-	-	-	-	-	-	-	-	-	-	-
Hydro Pacific	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)
Hydro Utah	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia	22	22	22	115	115	235	100	100	19	19	19
T&D Eff PPL	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)
T&D Eff UPL	(14)	(14)	(14)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
Water Budget	-	-	-	-	-	-	-	-	-	-	-
Wind Foote Creek	11	11	11	11	11	11	11	11	11	11	(6)
Total Renewables	(57)	(56)	(57)	(143)	(143)	(22)	(157)	(157)	(238)	(238)	(278)
Existing Generation	(82)	(81)	(90)	(176)	(411)	(290)	(425)	(600)	(2,018)	(5,418)	(7,347)
Purchases											
APS Sea Ex (P)	-	-	-	-	-	-	-	-	-	-	-
APS Sea Ex (S)	-	-	-	-	-	-	-	-	-	-	-
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-
Black Hills Capacity	-	-	-	-	-	-	-	-	-	-	-
Black Hills Purchase	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(P)	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(S)	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (P)	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (S)	-	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (P)	-	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (S)	-	-	-	-	-	-	-	-	-	-	-
CSPE	-	-	-	-	-	-	-	-	-	-	-
Deseret Annual	15	16	-	-	-	-	-	-	-	-	-
Deseret Expansion	-	-	-	-	-	-	-	-	-	-	-
Deseret NF	-	-	-	-	-	-	-	-	-	-	-
Gem State	-	-	-	-	-	-	-	-	-	-	-
Grant County	-	-	-	-	-	-	-	-	-	-	-
GSLM	-	-	-	-	-	-	-	-	-	-	-
Idaho Load Control	-	-	-	-	-	-	-	-	-	-	-
Interruptible Rep	-	-	-	-	-	-	-	-	-	-	-
IPC	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	-	-	-	-	-	-	-	-	-	-	-

QF Idaho	1	1	1	1	1	1	1	1	1	1	1
QF NW	-	-	-	-	-	-	-	-	-	-	-
QF UPL	-	-	-	-	-	-	-	-	-	-	-
San Juan Unit 4	1	1	1	1	1	1	1	1	1	-	-
SCE Winter	-	-	-	-	-	-	-	-	-	-	-
So Idaho Ex (P)	-	-	-	-	-	-	-	-	-	-	-
So Idaho Ex (S)	-	-	-	-	-	-	-	-	-	-	-
Tri-State Basic	-	-	-	-	-	-	-	-	-	-	-
Tri-State Ex (P)	-	-	-	-	-	-	-	-	-	-	-
Tri-State Ex (S)	-	-	-	-	-	-	-	-	-	-	-
USBR Greenspring	-	-	-	-	-	-	-	-	-	-	-
WWP Seasonal Ex (P)	-	-	-	-	-	-	-	-	-	-	-
WWP Seasonal Ex (S)	-	-	-	-	-	-	-	-	-	-	-
WWP Summer Purchase	-	-	-	-	-	-	-	-	-	-	-
Purchased Power	16	17	1	1	1	1	1	1	1	-	-
Total Resources	(66)	(64)	(89)	(175)	(410)	(289)	(424)	(599)	(2,017)	(5,418)	(7,346)
Sales											
APPA	-	35	15	25	-	-	-	-	-	-	-
Black Hills 1996	-	-	-	-	-	-	-	-	-	-	-
Black Hills Load	(5)	(11)	(16)	(20)	(25)	(25)	(25)	(25)	(25)	(25)	(25)
BPA Wind Sale	6	6	6	6	6	6	6	6	6	6	6
Canadian Entitlement	5	5	4	-	-	-	-	-	-	-	-
CDWR	-	-	-	-	-	-	-	-	-	-	-
Cheyenne	1	-	-	-	-	-	-	-	-	-	-
Citizens Power	80	80	80	-	-	-	-	-	-	-	-
Clark County PUD	(128)	(145)	-	-	-	-	-	-	-	-	-
Clark-FW	12	-	-	-	-	-	-	-	-	-	-
Clark-WT	10	10	10	-	-	-	-	-	-	-	-
Colockum	-	-	-	-	-	-	-	-	-	-	-
Cowlitz-BHP	-	-	(22)	-	-	-	-	-	-	-	-
EWEB	-	-	-	-	-	-	-	-	-	-	-
Green Mountain	-	-	-	-	-	-	-	-	-	-	-
Hinson	(76)	-	-	-	-	-	-	-	-	-	-
Hurricane Net Sale	3	3	3	3	3	3	3	3	3	3	3
Interruptibles	-	-	-	-	-	-	-	-	-	-	-
Montana Sell Back	70	70	70	70	70	70	70	-	-	-	-
Okanogan	-	-	-	-	-	-	-	-	-	-	-
Plains Electric G&T	-	-	-	-	-	-	-	-	-	-	-
PNGC	-	-	-	-	-	-	-	-	-	-	-
PSCol	-	-	-	-	-	-	-	-	-	-	-
Puget 2	-	-	-	-	-	-	-	-	-	-	-
Redding	-	-	-	-	-	-	-	-	-	-	-
SCE OWC	-	-	-	-	-	-	-	-	-	-	-
SCE Utah	-	-	-	-	-	-	-	-	-	-	-
Sierra 1	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)
Sierra 2	-	-	-	-	-	-	-	-	-	-	-
SMUD	-	-	-	-	-	-	-	-	-	-	-
Springfield	-	-	-	-	-	-	-	-	-	-	-
Springfield II	-	-	-	-	-	-	-	-	-	-	-
UMPA 1	-	-	-	-	-	(8)	-	-	-	-	-
UMPA 2	-	-	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
WAPA 1	1	-	-	-	-	-	-	-	-	-	-
WAPA 2	-	-	-	-	-	-	-	-	-	-	-
Total Sales	(97)	(22)	75	8	(22)	(30)	(22)	(92)	(92)	(92)	(92)

RAMPP-6 Less RAMPP-5
Winter Capacity (MW)

R-6	2000	2001	2002	2003	2004	2005	2006	2007	2014	2019	2029
R-5	2000	2001	2002	2003	2004	2005	2006	200[illegible]	2012	201[illegible]	[illegible]
Thermal Plants											
Carbon 1,2	-	-	-	-	-	-	-	(175)	(175)	(175)	(175)
Centralia 1,2	-	-	-	-	-	-	-	-	(637)	(637)	(637)
Cholla 4	-	-	-	-	-	-	-	-	-	-	(380)
Colstrip 3,4	4	4	4	4	4	4	4	4	4	4	(140)
Craig 1,2	-	-	-	-	-	-	-	-	-	-	(165)
Dave Johnstn 1,2,3,4	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(780)	(780)
Gadsby 1,2,3	-	-	-	-	(235)	(235)	(235)	(235)	(235)	(235)	(235)
Hayden 1,2	-	-	-	-	-	-	-	-	-	-	(78)
Hermiston	-	-	-	-	-	-	-	-	-	-	-
Hunter 1,2,3	2	2	2	2	2	2	2	2	2	2	(1,120)
Huntington 1,2	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(922)	(922)
James River	2	2	2	2	2	2	2	2	2	(50)	(50)
Jim Bridger 1,2,3,4	(5)	2	2	2	2	2	2	2	2	(1,411)	(1,411)
Naughton 1,2,3	-	-	-	-	-	-	-	-	(700)	(700)	(700)
Wyodak	-	-	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(276)	(276)
Total Thermal	(32)	(25)	(33)	(33)	(268)	(268)	(268)	(443)	(1,780)	(5,180)	(7,069)
Renewables											
Blundell Geothermal	-	-	-	-	-	-	-	-	-	-	(23)
BPA Peaking	-	-	-	-	(175)	(175)	(175)	(175)	(175)	(175)	(175)
BPA Supp Capacity	5	5	5	4	(4)	-	-	-	-	-	-
Hydro Idaho	-	-	-	-	-	-	-	-	-	-	-
Hydro Pacific	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
Hydro Utah	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia	5	5	5	5	101	101	92	92	17	17	17
T&D Eff PPL	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)
T&D Eff UPL	(14)	(14)	(14)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
Water Budget	-	-	-	-	-	-	-	-	-	-	-
Wind Foote Creek	3	3	3	3	3	3	3	3	3	3	(25)
Total Renewables	(38)	(39)	(39)	(39)	(126)	(121)	(130)	(130)	(205)	(205)	(256)
Existing Generation	(70)	(64)	(72)	(72)	(394)	(389)	(398)	(573)	(1,985)	(5,385)	(7,325)
Purchases											
APS Sea Ex (P)	206	-	-	-	-	-	-	-	-	-	-
APS Sea Ex (S)	-	-	-	-	-	-	-	-	-	-	-
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-
Black Hills Capacity	-	-	-	-	-	-	-	-	(100)	-	-
Black Hills Purchase	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(P)	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(S)	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (P)	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (S)	-	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (P)	-	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (S)	-	-	-	-	-	-	-	-	-	-	-
CSPE	-	-	-	-	-	-	-	-	-	-	-
Deseret Annual	15	16	-	-	-	-	-	-	-	-	-
Deseret Expansion	-	-	-	-	-	-	-	-	-	-	-
Deseret NF	-	-	-	-	-	-	-	-	-	-	-
Gem State	-	-	-	-	-	-	-	-	-	-	-
Grant County	-	-	-	-	-	-	-	-	-	-	-
GSLM	-	-	-	-	-	-	-	-	-	-	-
Idaho Load Control	-	-	-	-	-	-	-	-	-	-	-
Interruptible Rep	-	-	-	-	-	-	-	-	-	-	-
IPC	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	-	-	-	-	-	-	-	-	-	-	-

QF Idaho	1	1	1	1	1	1	1	1	1	1	1
QF NW	-	-	-	-	-	-	-	-	-	-	-
QF UPL	-	-	-	-	-	-	-	-	-	-	-
San Juan Unit 4	1	1	1	1	1	1	1	1	1	-	-
SCE Winter	-	-	-	-	-	-	-	-	-	-	-
So Idaho Ex (P)	-	-	-	-	-	-	-	-	-	-	-
So Idaho Ex (S)	-	-	-	-	-	-	-	-	-	-	-
Tri-State Basic	-	-	-	-	-	-	-	-	-	-	-
Tri-State Ex (P)	-	-	-	-	-	-	-	-	-	-	-
Tri-State Ex (S)	-	-	-	-	-	-	-	-	-	-	-
USBR Greenspring	-	-	-	-	-	-	-	-	-	-	-
WWP Seasonal Ex (P)	-	-	-	-	-	-	-	-	-	-	-
WWP Seasonal Ex (S)	-	-	-	-	-	-	-	-	-	-	-
WWP Summer Purchase	-	-	-	-	-	-	-	-	-	-	-
Purchased Power	222	17	1	1	1	1	1	1	(99)	-	-
Total Resources	152	(47)	(71)	(71)	(393)	(388)	(397)	(572)	(2,084)	(5,385)	(7,324)

Sales

APPA	-	-	-	-	-	-	-	-	-	-	-
Black Hills 1996	-	-	-	-	-	-	-	-	-	-	-
Black Hills Load	(5)	(11)	(16)	(20)	(25)	(25)	(25)	(25)	(25)	(25)	(25)
BPA Wind Sale	6	6	6	6	6	6	6	6	6	6	6
Canadian Entitlement	5	5	5	4	-	-	-	-	-	-	-
CDWR	-	-	-	-	-	-	-	-	-	-	-
Cheyenne	2	-	-	-	-	-	-	-	-	-	-
Citizens Power	85	85	85	-	-	-	-	-	-	-	-
Clark County PUD	(25)	(25)	-	-	-	-	-	-	-	-	-
Clark-FW	12	-	-	-	-	-	-	-	-	-	-
Clark-WT	10	10	10	-	-	-	-	-	-	-	-
Colockum	-	-	-	-	-	-	-	-	-	-	-
Cowlitz-BHP	-	-	-	-	-	-	-	-	-	-	-
EWEB	-	-	-	-	-	-	-	-	-	-	-
Green Mountain	-	-	-	-	-	-	-	-	-	-	-
Hinson	144	75	-	-	-	-	-	-	-	-	-
Hurricane Net Sale	3	3	3	3	3	3	3	3	3	3	3
Interruptibles	-	-	-	-	-	-	-	-	-	-	-
Montana Sell Back	70	70	70	70	70	70	70	-	-	-	-
Okanogan	-	-	-	-	-	-	-	-	-	-	-
Plains Electric G&T	(42)	-	-	-	-	-	-	-	-	-	-
PNGC	-	-	-	-	-	-	-	-	-	-	-
PSCol	-	-	-	-	-	-	-	-	-	-	-
Puget 2	-	-	-	-	-	-	-	-	-	-	-
Redding	-	-	-	-	-	-	-	-	-	-	-
SCE OWC	-	-	-	-	-	-	-	-	-	-	-
SCE Utah	-	-	-	-	-	-	-	-	-	-	-
Sierra 1	-	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)
Sierra 2	-	-	-	-	-	-	-	-	-	-	-
SMUD	-	-	-	-	-	-	-	-	-	-	-
Springfield	-	-	-	-	-	-	-	-	-	-	-
Springfield II	-	-	-	-	-	-	-	-	-	-	-
UMPA 1	-	-	-	-	-	-	-	-	-	-	-
UMPA 2	-	-	-	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
WAPA 1	1	-	-	-	-	-	-	-	-	-	-
WAPA 2	-	-	-	-	-	-	-	-	-	-	-
Total Sales	266	143	89	(13)	(22)	(22)	(22)	(92)	(92)	(92)	(92)

RAMPP-6 Less RAMPP-5
Annual Average Generation (MWa)

R-6 / R-5	2000 / 2000	2001 / 2001	2002 / 2002	2003 / 2003	2004 / 2004	2005 / 2005	2006 / 2006	2007 / 2007	2014 / [illegible]	2019 / [illegible]	2029 / [illegible]
Thermal Plants											
Carbon 1,2	-	-	-	-	-	-	-	(163)	(163)	(163)	(163)
Centralia 1,2	231	272	392	342	200	112	87	69	(543)	(573)	(570)
Cholla 4	102	80	80	134	132	134	141	134	64	62	(299)
Colstrip 3,4	4	4	4	4	4	4	4	4	4	4	(128)
Craig 1,2	-	-	-	-	-	-	-	-	-	-	(158)
Dave Johnstn 1,2,3,4	(7)	(8)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(723)	(723)
Gadsby 1,2,3	23	22	26	23	(94)	(94)	(94)	(94)	(109)	(110)	(110)
Hayden 1,2	-	-	-	-	-	-	-	-	-	-	(69)
Hermiston	5	5	5	5	5	5	5	5	5	5	5
Hunter 1,2,3	2	2	2	2	2	2	2	2	2	2	(1,052)
Huntington 1,2	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(852)	(852)
James River	36	38	36	33	27	26	26	26	8	(21)	(21)
Jim Bridger 1,2,3,4	(4)	2	2	2	2	2	2	2	2	(1,291)	(1,291)
Naughton 1,2,3	73	11	16	52	28	21	11	10	(652)	(652)	(652)
Wyodak	-	-	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(259)	(259)
Total Thermal	438	402	521	556	265	171	143	(46)	(1,422)	(4,571)	(6,342)
Renewables											
Blundell Geothermal	10	8	9	9	8	7	7	8	3	2	(7)
BPA Peaking	(256)	(246)	(233)	(255)	(256)	(241)	(256)	(256)	(256)	(256)	(256)
BPA Supp Capacity	(2)	(2)	(1)	(1)	(2)	-	-	-	-	-	-
Hydro Idaho	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Hydro Pacific	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
Hydro Utah	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Mid-Columbia	(18)	(18)	(18)	(18)	(18)	(18)	(13)	(13)	(1)	(1)	(1)
T&D Eff PPL	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)
T&D Eff UPL	(11)	(11)	(12)	(11)	(11)	(12)	(12)	(12)	(12)	(12)	(12)
Water Budget	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)
Wind Foote Creek	1	1	1	1	1	1	1	1	1	1	(11)
Total Renewables	(402)	(395)	(381)	(403)	(404)	(390)	(399)	(398)	(392)	(392)	(413)
Existing Generation	36	7	140	153	(140)	(218)	(256)	(445)	(1,815)	(4,963)	(6,755)
Purchases											
APS Sea Ex (P)	-	-	-	-	-	-	-	-	-	-	-
APS Sea Ex (S)	-	-	-	-	-	-	-	-	-	-	-
APS Supplemental	-	-	-	-	-	-	-	1	-	-	-
Black Hills Capacity	-	-	-	-	-	-	-	-	-	-	-
Black Hills Purchase	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(P)	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(S)	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (P)	-	-	-	-	-	-	-	-	(6)	-	-
BPA Spring Ex (S)	-	-	-	-	-	-	-	-	6	-	-
BPA Summer Ex (P)	-	-	-	-	-	-	-	-	(14)	-	-
BPA Summer Ex (S)	-	-	-	-	-	-	-	-	14	-	-
CSPE	-	-	-	(7)	-	-	-	-	-	-	-
Deseret Annual	-	(10)	-	-	-	-	-	-	-	-	-
Deseret Expansion	(1)	(2)	-	-	-	-	-	-	-	-	-
Deseret NF	(1)	(5)	-	-	-	-	-	-	-	-	-
Gem State	1	1	1	1	1	1	1	1	1	1	1
Grant County	-	-	-	-	-	-	-	-	-	-	-
GSLM	-	-	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Idaho Load Control	-	-	-	-	-	-	-	-	-	-	-
Interruptible Rep	2	2	2	2	2	2	3	2	3	2	3
IPC	1	1	1	1	1	1	1	1	1	1	1
PGE Cove	-	-	-	-	-	-	-	-	-	-	-

QF Idaho	-	-	-	-	-	-	-	-	-	-	-
QF NW	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
QF UPL	2	2	2	2	2	2	2	2	2	2	2
San Juan Unit 4	-	-	-	-	-	-	-	-	(1)	-	-
SCE Winter	(3)	(3)	(3)	-	-	-	-	-	-	-	-
So Idaho Ex (P)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(92)	(92)	(92)
So Idaho Ex (S)	50	50	50	50	50	50	50	50	92	92	92
Tri-State Basic	-	-	-	-	-	-	-	-	-	-	-
Tri-State Ex (P)	-	-	-	-	-	-	-	-	-	-	-
Tri-State Ex (S)	-	-	-	-	-	-	-	-	-	-	-
USBR Greenspring	3	-	-	-	-	-	-	-	-	-	-
WWP Seasonal Ex (P)	-	-	-	-	-	-	-	-	-	-	-
WWP Seasonal Ex (S)	-	-	-	-	-	-	-	-	-	-	-
WWP Summer Purchase	-	-	-	-	-	-	-	-	-	-	-
Purchased Power	(17)	(36)	(23)	(27)	(21)	(21)	(20)	(20)	(112)	(93)	(92)
Total Resources	19	(29)	117	125	(160)	(239)	(275)	(465)	(1,927)	(5,056)	(6,847)
Sales											
APPA	-	4	2	3	-	-	-	-	-	-	-
Black Hills 1996	-	-	-	-	-	-	-	-	-	-	-
Black Hills Load	(8)	(10)	(12)	(14)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
BPA Wind Sale	6	6	6	6	6	6	6	6	6	6	6
Canadian Entitlement	2	2	2	-	-	-	-	-	-	-	-
CDWR	-	-	-	-	-	-	-	-	-	-	-
Cheyenne	3	-	-	-	-	-	-	-	-	-	-
Citizens Power	19	19	12	-	-	-	-	-	-	-	-
Clark County PUD	3	(16)	-	-	-	-	-	-	-	-	-
Clark-FW	9	-	-	-	-	-	-	-	-	-	-
Clark-WT	10	10	10	-	-	-	-	-	-	-	-
Colockum	(5)	(5)	(5)	(6)	-	-	-	-	-	-	-
Cowlitz-BHP	-	-	(2)	-	-	-	-	-	-	-	-
EWEB	(3)	-	-	-	-	-	-	-	-	-	-
Green Mountain	39	17	13	13	2	-	-	-	-	-	-
Hinson	15	19	-	-	-	-	-	-	-	-	-
Hurricane Net Sale	2	2	2	2	2	2	2	2	2	2	2
Interruptibles	-	-	-	-	-	-	-	-	-	-	-
Montana Sell Back	70	70	70	70	70	70	53	-	-	-	-
Okanogan	1	-	-	-	-	-	-	-	-	-	-
Plains Electric G&T	-	-	-	-	-	-	-	-	-	-	-
PNGC	(4)	(2)	-	-	-	-	-	-	-	-	-
PSCol	-	-	-	-	-	-	-	-	-	-	-
Puget 2	-	-	-	-	-	-	-	-	-	-	-
Redding	-	6	6	6	6	6	6	6	-	-	-
SCE OWC	(16)	(16)	(16)	(16)	(16)	(16)	(12)	-	-	-	-
SCE Utah	(16)	(16)	(16)	(16)	(16)	(16)	(12)	-	-	-	-
Sierra 1	(57)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)
Sierra 2	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	-	-	-
SMUD	-	-	-	-	-	-	-	-	-	-	-
Springfield	-	-	-	-	-	-	-	-	-	-	-
Springfield II	-	-	(2)	-	-	-	-	-	-	-	-
UMPA 1	(1)	(1)	(1)	(1)	(1)	-	-	-	-	-	-
UMPA 2	-	-	-	-	-	-	-	-	-	-	-
WAPA 1	-	(1)	-	-	-	-	-	-	-	-	-
WAPA 2	-	-	-	-	-	-	-	-	-	-	-
Total Sales	17	(37)	(58)	(79)	(89)	(91)	(100)	(128)	(196)	(176)	(176)

RAMPP-6 Base Case
Summer Capacity (MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2014	2019	2029
Thermal Plants													
Carbon 1,2	175	175	175	175	175	175	175						
Centralia 1,2	637	637	637	637	637	637	637	637	637	637			
Cholla 4	380	380	380	380	380	380	380	380	380	380	380	380	
Colstrip 3,4	144	144	144	144	144	144	144	144	144	144	144	144	
Craig 1,2	165	165	165	165	165	165	165	165	165	165	165	165	
Dave Johnstn 1,2,3,4	772	772	772	772	772	772	772	772	772	772	772		
Gadsby 1,2,3	235	235	235	235									
Hayden 1,2	78	78	78	78	78	78	78	78	78	78	78	78	
Hermiston	454	454	454	454	454	454	454	454	454	454	454	454	454
Hunter 1,2,3	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	
Huntington 1,2	895	895	895	895	895	895	895	895	895	895	895		
James River	52	52	52	52	52	52	52	52	52	52	52		
Jim Bridger 1,2,3,4	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413		
Naughton 1,2,3	700	700	700	700	700	700	700	700	700				
Wyodak	268	268	268	268	268	268	268	268	268	268	268		
Total Thermal	7,490	7,490	7,490	7,490	7,255	7,255	7,255	7,080	7,080	6,380	5,743	2,343	454
Renewables													
Blundell Geothermal	23	23	23	23	23	23	23	23	23	23	23	23	
BPA Peaking	925	925	925	750	750	750	750	750	750	750	750	750	750
BPA Supp Capacity	9	9	8	-	-	-	-	-	-	-	-	-	-
Hydro Idaho	54	54	54	54	54	54	54	54	54	54	54	54	54
Hydro Pacific	869	869	869	869	869	869	869	869	869	869	869	869	869
Hydro Utah	36	36	36	36	36	36	36	36	36	36	36	36	36
Mid-Columbia	422	422	422	422	422	422	287	287	287	287	55	55	55
T&D Eff PPL	5	10	14	17	20	22	25	28	31	34	43	43	43
T&D Eff UPL	2	4	7	9	10	12	13	14	15	16	19	19	19
Water Budget	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Foote Creek	16	16	16	16	16	16	16	16	16	16	16	16	
Total Renewables	2,361	2,368	2,374	2,196	2,200	2,204	2,073	2,077	2,081	2,085	1,865	1,865	1,825
Existing Generation	9,851	9,858	9,864	9,686	9,455	9,459	9,328	9,157	9,161	8,465	7,608	4,208	2,279
Purchases													
APS Sea Ex (P)	-	-	-	-	-	-	-	-	-	-	-	-	-
APS Sea Ex (S)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills Capacity	68	68	68	68	68	68	68	68	68	68	-	-	-
Black Hills Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(P)	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(S)	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (P)	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (S)	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (P)	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (S)	-	-	-	-	-	-	-	-	-	-	-	-	-
CSPE	18	18	16	-	-	-	-	-	-	-	-	-	-
Deseret Annual	262	261	-	-	-	-	-	-	-	-	-	-	-
Deseret Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-
Deseret NF	-	-	-	-	-	-	-	-	-	-	-	-	-
Gem State	22	22	22	22	22	22	22	22	22	22	22	22	22
Grant County	14	14	14	14	14	14	14	14	14	14	14	14	14
GSLM	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho Load Control	150	150	150	150	150	150	150	150	150	150	150	150	150
Interruptible Rep	-	-	-	-	-	-	-	-	-	-	-	-	-
IPC	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
PGE Cove	3	2	2	2	2	2	2	2	2	2	2	2	2

QF Idaho	22	22	22	22	22	22	22	22	22	22	22	22	
QF NW	102	102	102	102	102	102	102	102	102	102	102	102	
QF UPL	57	57	57	57	57	57	57	57	57	57	57	57	
San Juan Unit 4	22	22	22	22	22	22	22	22	22	22	22	-	
SCE Winter	-	-	-	-	-	-	-	-	-	-	-	-	
So Idaho Ex (P)	-	-	-	-	-	-	-	-	-	-	-	-	
So Idaho Ex (S)	-	-	-	-	-	-	-	-	-	-	-	-	
Tri-State Basic	50	50	50	50	50	50	50	50	50	50	50	50	
Tri-State Ex (P)	-	-	-	-	-	-	-	-	-	-	-	-	
Tri-State Ex (S)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	-	-	-	-	-	
USBR Greenspring	18	-	-	-	-	-	-	-	-	-	-	-	
WWP Seasonal Ex (P)	50	50	50	50	50	50	50	50	50	-	-	-	
WWP Seasonal Ex (S)	-	-	-	-	-	-	-	-	-	-	-	-	
WWP Summer Purchase	150	150	150	150	-	-	-	-	-	-	-	-	
Purchased Power	1,008	987	724	708	558	558	558	558	558	508	440	419	
Total Resources	10,859	10,845	10,588	10,394	10,013	10,017	9,886	9,715	9,719	8,973	8,048	4,626	2

Sales

APPA	95	35	15	25	-	-	-	-	-	-	-	-	
Black Hills 1996	30	30	30	-	-	-	-	-	-	-	-	-	
Black Hills Load	70	64	60	55	50	50	50	50	50	50	50	50	
BPA Wind Sale	6	6	6	6	6	6	6	6	6	6	6	6	
Canadian Entitlement	5	5	4	-	-	-	-	-	-	-	-	-	
CDWR	100	100	100	100	100	-	-	-	-	-	-	-	
Cheyenne	141	-	-	-	-	-	-	-	-	-	-	-	
Citizens Power	80	80	80	-	-	-	-	-	-	-	-	-	
Clark County PUD	100	100	-	-	-	-	-	-	-	-	-	-	
Clark-FW	12	-	-	-	-	-	-	-	-	-	-	-	
Clark-WT	10	10	10	-	-	-	-	-	-	-	-	-	
Colockum	-	-	-	-	-	-	-	-	-	-	-	-	
Cowlitz-BHP	22	22	-	-	-	-	-	-	-	-	-	-	
EWEB	50	-	-	-	-	-	-	-	-	-	-	-	
Green Mountain	-	-	-	-	-	-	-	-	-	-	-	-	
Hinson	-	-	-	-	-	-	-	-	-	-	-	-	
Hurricane Net Sale	3	3	3	3	3	3	3	3	3	3	3	3	
Interruptibles	-	-	-	-	-	-	-	-	-	-	-	-	-
Montana Sell Back	70	70	70	70	70	70	70	-	-	-	-	-	-
Okanogan	5	5	-	-	-	-	-	-	-	-	-	-	-
Plains Electric G&T	-	-	-	-	-	-	-	-	-	-	-	-	-
PNGC	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCol	176	176	176	176	176	176	176	176	176	176	176	176	1
Puget 2	200	200	200	200	-	-	-	-	-	-	-	-	-
Redding	50	50	50	50	50	50	50	50	50	50	-	-	-
SCE OWC	100	100	100	100	100	100	100	-	-	-	-	-	-
SCE Utah	100	100	100	100	100	100	100	-	-	-	-	-	-
Sierra 1	-	-	-	-	-	-	-	-	-	-	-	-	-
Sierra 2	75	75	75	75	75	75	75	75	75	75	-	-	-
SMUD	100	100	100	100	100	100	100	100	100	100	100	-	-
Springfield	45	45	45	45	45	45	45	45	45	45	45	-	-
Springfield II	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA 1	8	8	8	8	8	-	-	-	-	-	-	-	-
UMPA 2	19	21	25	25	25	25	25	25	25	25	25	25	
WAPA 1	60	48	48	48	48	-	-	-	-	-	-	-	-
WAPA 2	75	75	75	75	75	-	-	-	-	-	-	-	-
Total Sales	2,347	2,069	1,919	1,800	1,571	1,340	1,340	1,020	1,020	1,020	895	750	7

RAMPP-6 Base Case
Winter Capacity (MW)

Thermal Plants	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2014	2019	202[illegible]
Carbon 1,2	175	175	175	175	175	175	175	-	-	-	-	-	-
Centralia 1,2	637	637	637	637	637	637	637	637	637	637	-	-	-
Cholla 4	380	380	380	380	380	380	380	380	380	380	380	380	-
Colstrip 3,4	144	144	144	144	144	144	144	144	144	144	144	144	-
Craig 1,2	165	165	165	165	165	165	165	165	165	165	165	165	-
Dave Johnstn 1,2,3,4	772	772	772	772	772	772	772	772	772	772	772	-	-
Gadsby 1,2,3	235	235	235	235	-	-	-	-	-	-	-	-	-
Hayden 1,2	78	78	78	78	78	78	78	78	78	78	78	78	-
Hermiston	492	492	492	492	492	492	492	492	492	492	492	492	492
Hunter 1,2,3	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	-
Huntington 1,2	895	895	895	895	895	895	895	895	895	895	895	-	-
James River	52	52	52	52	52	52	52	52	52	52	52	-	-
Jim Bridger 1,2,3,4	1,406	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	-	-
Naughton 1,2,3	700	700	700	700	700	700	700	700	700	-	-	-	-
Wyodak	268	268	268	268	268	268	268	268	268	268	268	-	-
Total Thermal	7,521	7,528	7,528	7,528	7,293	7,293	7,293	7,118	7,118	6,418	5,781	2,381	492
Renewables													
Blundell Geothermal	23	23	23	23	23	23	23	23	23	23	23	23	-
BPA Peaking	925	925	925	925	750	750	750	750	750	750	750	750	750
BPA Supp Capacity	10	9	9	8	-	-	-	-	-	-	-	-	-
Hydro Idaho	30	30	30	30	30	30	30	30	30	30	30	30	30
Hydro Pacific	902	902	902	902	902	902	902	902	902	902	902	902	902
Hydro Utah	20	20	20	20	20	20	20	20	20	20	20	20	20
Mid-Columbia	422	422	422	422	422	422	287	287	287	287	55	55	55
T&D Eff PPL	5	10	14	17	20	22	25	28	31	34	43	43	43
T&D Eff UPL	2	4	7	9	10	12	13	14	15	16	19	19	19
Water Budget	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Foote Creek	28	28	28	28	28	28	28	28	28	28	28	28	-
Total Renewables	2,367	2,373	2,380	2,383	2,204	2,208	2,077	2,081	2,085	2,089	1,869	1,869	1,818
Existing Generation	9,888	9,901	9,908	9,911	9,497	9,501	9,370	9,199	9,203	8,507	7,650	4,250	2,310
Purchases													
APS Sea Ex (P)	480	480	480	480	480	480	480	480	480	480	480	480	480
APS Sea Ex (S)	-	-	-	-	-	-	-	-	-	-	-	-	-
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills Capacity	100	100	100	100	100	100	100	100	100	100	-	-	-
Black Hills Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(P)	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(S)	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (P)	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (S)	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (P)	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (S)	-	-	-	-	-	-	-	-	-	-	-	-	-
CSPE	19	18	18	16	-	-	-	-	-	-	-	-	-
Deseret Annual	262	261	-	-	-	-	-	-	-	-	-	-	-
Deseret Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-
Deseret NF	-	-	-	-	-	-	-	-	-	-	-	-	-
Gem State	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant County	14	14	14	14	14	14	14	14	14	14	14	14	14
GSLM	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-
Interruptible Rep	-	-	-	-	-	-	-	-	-	-	-	-	-
IPC	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
PGE Cove	3	2	2	2	2	2	2	2	2	2	2	2	2

QF Idaho	22	22	22	22	22	22	22	22	22	22	22	22	
QF NW	102	102	102	102	102	102	102	102	102	102	102	102	
QF UPL	57	57	57	57	57	57	57	57	57	57	57	57	
San Juan Unit 4	22	22	22	22	22	22	22	22	22	22	22	-	
SCE Winter	422	422	422	422	-	-	-	-	-	-	-	-	
So Idaho Ex (P)	-	-	-	-	-	-	-	-	-	-	-	-	
So Idaho Ex (S)	-	-	-	-	-	-	-	-	-	-	-	-	
Tri-State Basic	50	50	50	50	50	50	50	50	50	50	50	50	
Tri-State Ex (P)	50	50	50	50	50	50	50	-	-	-	-	-	
Tri-State Ex (S)	-	-	-	-	-	-	-	-	-	-	-	-	
USBR Greenspring	18	-	-	-	-	-	-	-	-	-	-	-	
WWP Seasonal Ex (P)	-	-	-	-	-	-	-	-	-	-	-	-	
WWP Seasonal Ex (S)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	-	-	
WWP Summer Purchase	-	-	-	-	-	-	-	-	-	-	-	-	
Purchased Power	1,621	1,600	1,338	1,336	898	898	898	848	848	848	748	727	
Total Resources	11,509	11,500	11,246	11,247	10,395	10,399	10,268	10,047	10,051	9,355	8,398	4,977	3,

Sales

APPA	-	-	-	-	-	-	-	-	-	-	-	-	
Black Hills 1996	15	15	15	-	-	-	-	-	-	-	-	-	
Black Hills Load	70	64	60	55	50	50	50	50	50	50	50	50	
BPA Wind Sale	6	6	6	6	6	6	6	6	6	6	6	6	
Canadian Entitlement	5	5	5	4	-	-	-	-	-	-	-	-	
CDWR	100	100	100	100	100	-	-	-	-	-	-	-	
Cheyenne	147	-	-	-	-	-	-	-	-	-	-	-	
Citizens Power	85	85	85	-	-	-	-	-	-	-	-	-	
Clark County PUD	325	325	-	-	-	-	-	-	-	-	-	-	
Clark-FW	12	-	-	-	-	-	-	-	-	-	-	-	
Clark-WT	10	10	10	-	-	-	-	-	-	-	-	-	
Colockum	-	-	-	-	-	-	-	-	-	-	-	-	
Cowlitz-BHP	22	22	22	-	-	-	-	-	-	-	-	-	
EWEB	50	-	-	-	-	-	-	-	-	-	-	-	
Green Mountain	-	-	-	-	-	-	-	-	-	-	-	-	
Hinson	220	75	-	-	-	-	-	-	-	-	-	-	
Hurricane Net Sale	3	3	3	3	3	3	3	3	3	3	3	3	
Interruptibles	-	-	-	-	-	-	-	-	-	-	-	-	
Montana Sell Back	70	70	70	70	70	70	70	-	-	-	-	-	
Okanogan	8	7	-	-	-	-	-	-	-	-	-	-	
Plains Electric G&T	-	-	-	-	-	-	-	-	-	-	-	-	
PNGC	55	60	-	-	-	-	-	-	-	-	-	-	
PSCol	176	176	176	176	176	176	176	176	176	176	176	176	1
Puget 2	200	200	200	200	-	-	-	-	-	-	-	-	
Redding	50	50	50	50	50	50	50	50	50	50	-	-	
SCE OWC	100	100	100	100	100	100	100	-	-	-	-	-	
SCE Utah	100	100	100	100	100	100	100	-	-	-	-	-	
Sierra 1	75	-	-	-	-	-	-	-	-	-	-	-	
Sierra 2	75	75	75	75	75	75	75	75	75	75	-	-	
SMUD	100	100	100	100	100	100	100	100	100	100	100	-	
Springfield	30	30	30	30	30	30	30	30	30	30	30	-	
Springfield II	50	50	50	-	-	-	-	-	-	-	-	-	
UMPA 1	8	8	8	8	8	8	-	-	-	-	-	-	
UMPA 2	14	19	21	25	25	25	25	25	25	25	25	25	
WAPA 1	60	48	48	48	48	-	-	-	-	-	-	-	
WAPA 2	75	75	75	75	75	-	-	-	-	-	-	-	
Total Sales	2,376	1,939	1,469	1,285	1,076	853	845	575	575	575	400	270	2

RAMPP-6 Base Case
Annual Average Generation (MWa)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2014	2019	202
Thermal Plants													
Carbon 1,2	162	163	169	163	163	163	163	-	-	-	-	-	-
Centralia 1,2	587	547	548	568	573	569	574	569	579	570	-	-	-
Cholla 4	316	316	300	364	362	364	364	364	364	362	355	361	-
Colstrip 3,4	130	135	130	132	132	132	132	132	132	132	132	132	-
Craig 1,2	153	159	162	158	158	158	158	158	158	158	158	158	-
Dave Johnstn 1,2,3,4	710	725	723	716	716	716	716	716	716	716	716	-	-
Gadsby 1,2,3	117	116	120	117	-	-	-	-	-	-	-	-	-
Hayden 1,2	71	72	71	69	69	69	69	69	69	69	69	69	-
Hermiston	446	446	437	444	444	444	444	444	444	444	444	444	444
Hunter 1,2,3	1,039	1,039	1,080	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	-
Huntington 1,2	839	830	830	827	827	827	827	827	827	827	827	-	-
James River	37	38	36	33	29	33	33	33	33	33	29	-	-
Jim Bridger 1,2,3,4	1,289	1,295	1,295	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	-	-
Naughton 1,2,3	661	648	657	652	652	652	652	652	652	-	-	-	-
Wyodak	261	236	261	252	252	252	252	252	252	252	252	-	-
Total Thermal	6,817	6,764	6,819	6,841	6,724	6,725	6,730	6,562	6,571	5,908	5,327	2,218	444
Renewables													
Blundell Geothermal	10	9	9	9	9	8	9	10	10	8	8	9	-
BPA Peaking	1	1	1	1	1	1	1	1	1	1	1	1	1
BPA Supp Capacity	0	0	0	0	-	-	-	-	-	-	-	-	-
Hydro Idaho	32	32	32	32	32	32	32	32	32	32	32	32	32
Hydro Pacific	499	499	499	499	499	499	499	499	499	499	499	499	499
Hydro Utah	22	22	22	22	22	22	22	22	22	22	22	22	22
Mid-Columbia	236	236	236	236	236	236	161	161	161	161	31	31	31
T&D Eff PPL	3	7	10	12	13	15	17	19	21	23	29	29	29
T&D Eff UPL	1	3	5	6	7	8	9	10	10	11	13	13	13
Water Budget	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Foote Creek	12	12	12	12	12	12	12	12	12	12	12	12	-
Total Renewables	816	819	825	828	830	832	760	764	767	768	646	647	626
Existing Generation	7,633	7,584	7,644	7,669	7,554	7,557	7,490	7,325	7,337	6,676	5,973	2,864	1,070
Purchases													
APS Sea Ex (P)	64	64	64	64	64	64	64	64	64	64	64	64	64
APS Sea Ex (S)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)
APS Supplemental	-	-	-	-	-	-	-	1	6	-	-	-	-
Black Hills Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills Purchase	26	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(P)	3	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(S)	(3)	-	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (P)	6	6	6	6	6	6	6	6	6	6	-	-	-
BPA Spring Ex (S)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	-	-	-
BPA Summer Ex (P)	14	14	14	14	14	14	14	14	14	14	-	-	-
BPA Summer Ex (S)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	-	-	-
CSPE	10	9	9	2	-	-	-	-	-	-	-	-	-
Deseret Annual	248	143	-	-	-	-	-	-	-	-	-	-	-
Deseret Expansion	26	12	-	-	-	-	-	-	-	-	-	-	-
Deseret NF	49	19	-	-	-	-	-	-	-	-	-	-	-
Gem State	6	6	6	6	6	6	6	6	6	6	6	6	6
Grant County	10	10	10	10	10	10	10	10	10	10	10	10	10
GSLM	5	5											
Idaho Load Control	0	0	0	0	0	0	0	0	0	0	0	0	0
Interruptible Rep	2	2	2	2	2	2	3	2	2	2	3	3	3
IPC	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
PGE Cove	3	1	1	1	1	1	1	1	1	1	1	1	1

QF Idaho	8	8	8	8	8	8	8	8	8	8	8	8	
QF NW	58	58	58	58	58	58	58	58	58	58	58	58	
QF UPL	41	41	41	41	41	41	41	41	41	41	41	41	
San Juan Unit 4	15	15	15	15	15	15	15	15	15	15	15	-	
SCE Winter	3	3	3	4	-	-	-	-	-	-	-	-	
So Idaho Ex (P)	72	72	72	72	72	72	72	72	72	72	-	-	
So Idaho Ex (S)	(42)	(42)	(42)	(42)	(42)	(42)	(42)	(42)	(42)	(42)	-	-	
Tri-State Basic	33	33	33	33	33	33	33	33	33	33	33	33	
Tri-State Ex (P)	19	19	19	19	19	19	19	-	-	-	-	-	
Tri-State Ex (S)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	-	-	-	-	-	
USBR Greenspring	7	-	-	-	-	-	-	-	-	-	-	-	
WWP Seasonal Ex (P)	3	3	3	3	3	3	3	3	3	3	-	-	
WWP Seasonal Ex (S)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	-	-	
WWP Summer Purchase	9	9	9	9	-	-	-	-	-	-	-	-	
Purchased Power	739	554	374	368	353	353	354	335	340	334	240	225	
Total Resources	8,372	8,137	8,018	8,037	7,907	7,910	7,844	7,660	7,677	7,010	6,213	3,089	1.
Sales													
APPA	23	4	2	3	-	-	-	-	-	-	-	-	
Black Hills 1996	-	-	-	-	-	-	-	-	-	-	-	-	
Black Hills Load	28	26	24	22	20	20	20	20	20	20	20	20	
BPA Wind Sale	6	6	6	6	6	6	6	6	6	6	6	6	
Canadian Entitlement	2	2	2	0	-	-	-	-	-	-	-	-	
CDWR	70	70	70	70	70	-	-	-	-	-	-	-	
Cheyenne	112	-	-	-	-	-	-	-	-	-	-	-	
Citizens Power	19	19	12	-	-	-	-	-	-	-	-	-	
Clark County PUD	145	86	-	-	-	-	-	-	-	-	-	-	
Clark-FW	9	-	-	-	-	-	-	-	-	-	-	-	
Clark-WT	10	10	10	-	-	-	-	-	-	-	-	-	
Colockum	18	18	18	5	-	-	-	-	-	-	-	-	
Cowlitz-BHP	19	19	6	-	-	-	-	-	-	-	-	-	
EWEB	21	-	-	-	-	-	-	-	-	-	-	-	
Green Mountain	39	17	13	13	2	-	-	-	-	-	-	-	
Hinson	91	19	-	-	-	-	-	-	-	-	-	-	
Hurricane Net Sale	2	2	2	2	2	2	2	2	2	2	2	2	
Interruptibles	311	311	311	311	311	311	311	311	311	311	311	311	
Montana Sell Back	70	70	70	70	70	70	53	-	-	-	-	-	
Okanogan	5	3	-	-	-	-	-	-	-	-	-	-	
Plains Electric G&T	24	-	-	-	-	-	-	-	-	-	-	-	
PNGC	26	12	-	-	-	-	-	-	-	-	-	-	
PSCol	132	132	132	132	132	132	132	132	132	132	132	132	
Puget 2	120	120	120	99	-	-	-	-	-	-	-	-	
Redding	43	43	43	43	43	43	43	43	43	43	-	-	
SCE OWC	54	54	54	54	54	54	40	-	-	-	-	-	
SCE Utah	54	54	54	54	54	54	40	-	-	-	-	-	
Sierra 1	18	-	-	-	-	-	-	-	-	-	-	-	
Sierra 2	53	53	53	53	53	53	53	53	53	13	-	-	
SMUD	40	40	40	40	40	40	40	40	40	40	40	-	
Springfield	24	24	24	24	24	24	24	24	24	24	24	-	
Springfield II	17	17	8	-	-	-	-	-	-	-	-	-	
UMPA 1	4	4	4	4	4	2	-	-	-	-	-	-	
UMPA 2	7	8	9	10	10	10	10	10	10	10	10	10	
WAPA 1	43	35	35	35	35	-	-	-	-	-	-	-	
WAPA 2	64	64	64	64	64	-	-	-	-	-	-	-	
Total Sales	1,883	1,499	1,342	1,271	1,151	978	931	779	779	739	619	555	5

RAMPP-5 Base Case
Summer Capacity (MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2027
Thermal Plants											
Carbon 1,2	175	175	175	175	175	175	175	175	175	175	175
Centralia 1,2	637	637	637	637	637	637	637	637	637	637	637
Cholla 4	380	380	380	380	380	380	380	380	380	380	380
Colstrip 3,4	140	140	140	140	140	140	140	140	140	140	140
Craig 1,2	165	165	165	165	165	165	165	165	165	165	165
Dave Johnstn 1,2,3,4	780	780	780	780	780	780	780	780	780	780	780
Gadsby 1,2,3	235	235	235	235	235	235	235	235	235	235	235
Hayden 1,2	78	78	78	78	78	78	78	78	78	78	78
Hermiston	454	454	454	454	454	454	454	454	454	454	454
Hunter 1,2,3	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
Huntington 1,2	922	922	922	922	922	922	922	922	922	922	922
James River	50	50	50	50	50	50	50	50	50	50	50
Jim Bridger 1,2,3,4	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411
Naughton 1,2,3	700	700	700	700	700	700	700	700	700	700	700
Wyodak	268	268	276	276	276	276	276	276	276	276	276
Total Thermal	7,515	7,515	7,523	7,523	7,523	7,523	7,523	7,523	7,523	7,523	7,523
Renewables											
Blundell Geothermal	23	23	23	23	23	23	23	23	23	23	23
BPA Peaking	925	925	925	925	925	925	925	925	925	925	925
BPA Supp Capacity	5	4	4	-	-	-	-	-	-	-	-
Hydro Idaho	54	54	54	54	54	54	54	54	54	54	54
Hydro Pacific	922	922	922	922	922	922	922	922	922	922	922
Hydro Utah	36	36	36	36	36	36	36	36	36	36	36
Mid-Columbia	400	400	400	307	307	186	186	186	36	36	36
T&D Eff PPL	32	37	42	44	47	49	52	55	70	70	70
T&D Eff UPL	16	18	20	22	23	25	26	27	32	32	32
Water Budget	-	-	-	-	-	-	-	-	-	-	-
Wind Foote Creek	6	6	6	6	6	6	6	6	6	6	6
Total Renewables	2,418	2,424	2,431	2,338	2,342	2,225	2,229	2,233	2,103	2,103	2,103
Existing Generation	9,933	9,939	9,954	9,861	9,865	9,748	9,752	9,756	9,626	9,626	9,626
Purchases											
APS Sea Ex (P)	-	-	-	-	-	-	-	-	-	-	-
APS Sea Ex (S)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)	(480)
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-
Black Hills Capacity	68	68	68	68	68	68	68	68	-	-	-
Black Hills Purchase	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(P)	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(S)	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (P)	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (S)	-	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (P)	-	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (S)	-	-	-	-	-	-	-	-	-	-	-
CSPE	18	17	16	-	-	-	-	-	-	-	-
Deseret Annual	248	245	-	-	-	-	-	-	-	-	-
Deseret Expansion	-	-	-	-	-	-	-	-	-	-	-
Deseret NF	-	-	-	-	-	-	-	-	-	-	-
Gem State	22	22	22	22	22	22	22	22	22	22	22
Grant County	14	14	14	14	14	14	14	14	14	14	14
GSLM	-	-	-	-	-	-	-	-	-	-	-
Idaho Load Control	150	150	150	150	150	150	150	150	150	150	150
Interruptible Rep	-	-	-	-	-	-	-	-	-	-	-
IPC	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
PGE Cove	3	2	2	2	2	2	2	2	2	2	2

QF Idaho	22	22	22	22	22	22	22	22	22	22	2
QF NW	102	102	102	102	102	102	102	102	102	102	10
QF UPL	57	57	57	57	57	57	57	57	57	57	5
San Juan Unit 4	21	21	21	21	21	21	21	21	21	-	-
SCE Winter	-	-	-	-	-	-	-	-	-	-	-
So Idaho Ex (P)	-	-	-	-	-	-	-	-	-	-	-
So Idaho Ex (S)	-	-	-	-	-	-	-	-	-	-	-
Tri-State Basic	50	50	50	50	50	50	50	50	50	50	5
Tri-State Ex (P)	-	-	-	-	-	-	-	-	-	-	-
Tri-State Ex (S)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	-	-	-	-
USBR Greenspring	18	-	-	-	-	-	-	-	-	-	-
WWP Seasonal Ex (P)	50	50	50	50	50	50	50	50	-	-	-
WWP Seasonal Ex (S)	-	-	-	-	-	-	-	-	-	-	-
WWP Summer Purchase	150	150	150	150	-	-	-	-	-	-	-
Purchased Power	992	970	723	708	558	558	558	558	440	419	41
Total Resources	10,926	10,909	10,677	10,569	10,423	10,306	10,310	10,314	10,065	10,044	10,04

Sales											
APPA	95	-	-	-	-	-	-	-	-	-	-
Black Hills 1996	30	30	30	-	-	-	-	-	-	-	-
Black Hills Load	75	75	75	75	75	75	75	75	75	75	7
BPA Wind Sale											
Canadian Entitlement	-	-	-	-	-	-	-	-	-	-	-
CDWR	100	100	100	100	100	-	-	-	-	-	-
Cheyenne	141	-	-	-	-	-	-	-	-	-	-
Citizens Power											
Clark County PUD	228	245	-	-	-	-	-	-	-	-	-
Clark-FW											
Clark-WT											
Colockum	-	-	-	-	-	-	-	-	-	-	-
Cowlitz-BHP	22	22	22	-	-	-	-	-	-	-	-
EWEB	50	-	-	-	-	-	-	-	-	-	-
Green Mountain											
Hinson	76	-	-	-	-	-	-	-	-	-	-
Hurricane Net Sale											
Interruptibles	-	-	-	-	-	-	-	-	-	-	-
Montana Sell Back											
Okanogan	5	5	-	-	-	-	-	-	-	-	-
Plains Electric G&T	-	-	-	-	-	-	-	-	-	-	-
PNGC	-	-	-	-	-	-	-	-	-	-	-
PSCol	176	176	176	176	176	176	176	176	176	176	176
Puget 2	200	200	200	200	-	-	-	-	-	-	-
Redding	50	50	50	50	50	50	50	50	-	-	-
SCE OWC	100	100	100	100	100	100	100	-	-	-	-
SCE Utah	100	100	100	100	100	100	100	-	-	-	-
Sierra 1	75	75	75	75	75	75	75	75	75	75	75
Sierra 2	75	75	75	75	75	75	75	75	-	-	-
SMUD	100	100	100	100	100	100	100	100	100	-	-
Springfield	45	45	45	45	45	45	45	45	45	-	-
Springfield II	-	-	-	-	-	-	-	-	-	-	-
UMPA 1	8	8	8	8	8	8	-	-	-	-	-
UMPA 2	19	21	25	25	25	25	25	25	25	25	25
WAPA 1	59	48	48	48	48	-	-	-	-	-	-
WAPA 2	75	75	75	75	75	-	-	-	-	-	-
Total Sales	2,444	2,091	1,845	1,793	1,593	1,370	1,362	1,112	987	842	842

RAMPP-5 Base Case
Winter Capacity (MW)

Thermal Plants	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2027
Carbon 1,2	175	175	175	175	175	175	175	175	175	175	175
Centralia 1,2	637	637	637	637	637	637	637	637	637	637	637
Cholla 4	380	380	380	380	380	380	380	380	380	380	380
Colstrip 3,4	140	140	140	140	140	140	140	140	140	140	140
Craig 1,2	165	165	165	165	165	165	165	165	165	165	165
Dave Johnstn 1,2,3,4	780	780	780	780	780	780	780	780	780	780	780
Gadsby 1,2,3	235	235	235	235	235	235	235	235	235	235	235
Hayden 1,2	78	78	78	78	78	78	78	78	78	78	78
Hermiston	492	492	492	492	492	492	492	492	492	492	492
Hunter 1,2,3	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
Huntington 1,2	922	922	922	922	922	922	922	922	922	922	922
James River	50	50	50	50	50	50	50	50	50	50	50
Jim Bridger 1,2,3,4	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411	1,411
Naughton 1,2,3	700	700	700	700	700	700	700	700	700	700	700
Wyodak	268	268	276	276	276	276	276	276	276	276	276
Total Thermal	7,553	7,553	7,561	7,561	7,561	7,561	7,561	7,561	7,561	7,561	7,561
Renewables											
Blundell Geothermal	23	23	23	23	23	23	23	23	23	23	23
BPA Peaking	925	925	925	925	925	925	925	925	925	925	925
BPA Supp Capacity	5	5	4	4	4	-	-	-	-	-	-
Hydro Idaho	30	30	30	30	30	30	30	30	30	30	30
Hydro Pacific	912	912	912	912	912	912	912	912	912	912	912
Hydro Utah	20	20	20	20	20	20	20	20	20	20	20
Mid-Columbia	417	417	417	417	321	321	194	194	38	38	38
T&D Eff PPL	32	37	42	44	47	49	52	55	70	70	70
T&D Eff UPL	16	18	20	22	23	25	26	27	32	32	32
Water Budget	-	-	-	-	-	-	-	-	-	-	-
Wind Foote Creek	25	25	25	25	25	25	25	25	25	25	25
Total Renewables	2,405	2,411	2,418	2,422	2,329	2,329	2,207	2,211	2,074	2,074	2,074
Existing Generation	9,958	9,964	9,979	9,983	9,890	9,890	9,768	9,772	9,635	9,635	9,635
Purchases											
APS Sea Ex (P)	274	480	480	480	480	480	480	480	480	480	480
APS Sea Ex (S)	-	-	-	-	-	-	-	-	-	-	-
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-
Black Hills Capacity	100	100	100	100	100	100	100	100	100	-	-
Black Hills Purchase	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(P)	-	-	-	-	-	-	-	-	-	-	-
Black Hills Store(S)	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (P)	-	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (S)	-	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (P)	-	-	-	-	-	-	-	-	-	-	-
BPA Summer Ex (S)	-	-	-	-	-	-	-	-	-	-	-
CSPE	19	18	17	16	-	-	-	-	-	-	-
Deseret Annual	248	245	-	-	-	-	-	-	-	-	-
Deseret Expansion	-	-	-	-	-	-	-	-	-	-	-
Deseret NF	-	-	-	-	-	-	-	-	-	-	-
Gem State	-	-	-	-	-	-	-	-	-	-	-
Grant County	14	14	14	14	14	14	14	14	14	14	14
GSLM	-	-	-	-	-	-	-	-	-	-	-
Idaho Load Control	-	-	-	-	-	-	-	-	-	-	-
Interruptible Rep	-	-	-	-	-	-	-	-	-	-	-
IPC	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
PGE Cove	3	2	2	2	2	2	2	2	2	2	2

QF Idaho	22	22	22	22	22	22	22	22	22	22	22
QF NW	102	102	102	102	102	102	102	102	102	102	102
QF UPL	57	57	57	57	57	57	57	57	57	57	57
San Juan Unit 4	21	21	21	21	21	21	21	21	21	-	-
SCE Winter	422	422	422	422	-	-	-	-	-	-	-
So Idaho Ex (P)	-	-	-	-	-	-	-	-	-	-	-
So Idaho Ex (S)	-	-	-	-	-	-	-	-	-	-	-
Tri-State Basic	50	50	50	50	50	50	50	50	50	50	50
Tri-State Ex (P)	50	50	50	50	50	50	50	-	-	-	-
Tri-State Ex (S)	-	-	-	-	-	-	-	-	-	-	-
USBR Greenspring	18	-	-	-	-	-	-	-	-	-	-
WWP Seasonal Ex (P)	-	-	-	-	-	-	-	-	-	-	-
WWP Seasonal Ex (S)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	-	-	-
WWP Summer Purchase	-	-	-	-	-	-	-	-	-	-	-
Purchased Power	1,399	1,582	1,337	1,335	898	898	898	848	848	727	727
Total Resources	11,357	11,547	11,316	11,318	10,788	10,787	10,665	10,619	10,482	10,361	10,361
Sales											
APPA	-	-	-	-	-	-	-	-	-	-	-
Black Hills 1996	15	15	15	-	-	-	-	-	-	-	-
Black Hills Load	75	75	75	75	75	75	75	75	75	75	75
BPA Wind Sale											
Canadian Entitlement	-	-	-	-	-	-	-	-	-	-	-
CDWR	100	100	100	100	100	-	-	-	-	-	-
Cheyenne	145	-	-	-	-	-	-	-	-	-	-
Citizens Power											
Clark County PUD	350	350	-	-	-	-	-	-	-	-	-
Clark-FW											
Clark-WT											
Colockum	-	-	-	-	-	-	-	-	-	-	-
Cowlitz-BHP	22	22	22	-	-	-	-	-	-	-	-
EWEB	50	-	-	-	-	-	-	-	-	-	-
Green Mountain											
Hinson	76	-	-	-	-	-	-	-	-	-	-
Hurricane Net Sale											
Interruptibles	-	-	-	-	-	-	-	-	-	-	-
Montana Sell Back											
Okanogan	8	7	-	-	-	-	-	-	-	-	-
Plains Electric G&T	42	-	-	-	-	-	-	-	-	-	-
PNGC	55	60	-	-	-	-	-	-	-	-	-
PSCol	176	176	176	176	176	176	176	176	176	176	176
Puget 2	200	200	200	200	-	-	-	-	-	-	-
Redding	50	50	50	50	50	50	50	50	-	-	-
SCE OWC	100	100	100	100	100	100	100	-	-	-	-
SCE Utah	100	100	100	100	100	100	100	-	-	-	-
Sierra 1	75	75	75	75	75	75	75	75	75	75	75
Sierra 2	75	75	75	75	75	75	75	75	-	-	-
SMUD	100	100	100	100	100	100	100	100	100	-	-
Springfield	30	30	30	30	30	30	30	30	30	-	-
Springfield II	50	50	50	-	-	-	-	-	-	-	-
UMPA 1	8	8	8	8	8	8	-	-	-	-	-
UMPA 2	14	19	21	25	25	25	25	25	25	25	25
WAPA 1	59	48	48	48	48	-	-	-	-	-	-
WAPA 2	75	75	75	75	75	-	-	-	-	-	-
Total Sales	2,110	1,795	1,380	1,297	1,097	875	867	667	492	362	362

RAMPP-5 Base Case
Annual Average Generation (MWa)

	2000	2001	2002	2003	2004	2005	2006	2007	2012	2017	2027
Thermal Plants											
Carbon 1,2	162	163	169	163	163	163	163	163	163	163	163
Centralia 1,2	356	275	156	227	373	457	488	500	543	573	570
Cholla 4	215	237	221	230	230	230	223	230	291	299	299
Colstrip 3,4	126	131	126	128	128	128	128	128	128	128	128
Craig 1,2	153	159	162	158	158	158	158	158	158	158	158
Dave Johnstn 1,2,3,4	717	732	730	723	723	723	723	723	723	723	723
Gadsby 1,2,3	94	94	94	94	94	94	94	94	109	110	110
Hayden 1,2	71	72	71	69	69	69	69	69	69	69	69
Hermiston	441	441	433	439	439	439	439	439	439	439	439
Hunter 1,2,3	1,038	1,037	1,079	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052
Huntington 1,2	864	855	855	852	852	852	852	852	852	852	852
James River	1	0	-	-	3	7	7	7	21	21	21
Jim Bridger 1,2,3,4	1,293	1,293	1,293	1,291	1,291	1,291	1,291	1,291	1,291	1,291	1,291
Naughton 1,2,3	588	638	641	600	624	631	641	642	652	652	652
Wyodak	261	236	268	259	259	259	259	259	259	259	259
Total Thermal	6,379	6,363	6,298	6,286	6,459	6,553	6,587	6,608	6,750	6,788	6,786
Renewables											
Blundell Geothermal	0	0	0	0	1	1	2	2	6	7	7
BPA Peaking	257	247	234	256	257	242	257	257	257	257	257
BPA Supp Capacity	2	2	1	1	2	-	-	-	-	-	-
Hydro Idaho	33	33	33	33	33	33	33	33	33	33	33
Hydro Pacific	514	514	514	514	514	514	514	514	514	514	514
Hydro Utah	22	22	22	22	22	22	22	22	22	22	22
Mid-Columbia	255	255	255	255	255	255	174	174	32	32	32
T&D Eff PPL	22	25	29	30	32	34	36	38	48	48	48
T&D Eff UPL	13	14	16	17	18	20	21	22	26	26	26
Water Budget	90	90	90	90	90	90	90	90	90	90	90
Wind Foote Creek	11	11	11	11	11	11	11	11	11	11	11
Total Renewables	1,218	1,214	1,205	1,231	1,234	1,222	1,159	1,162	1,038	1,039	1,039
Existing Generation	7,598	7,577	7,503	7,516	7,693	7,775	7,746	7,770	7,788	7,828	7,825
Purchases											
APS Sea Ex (P)	64	64	64	64	64	64	64	64	64	64	64
APS Sea Ex (S)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-
Black Hills Capacity	-	-	-	-	-	-	-	-	-	-	-
Black Hills Purchase	26	-	-	-	-	-	-	-	-	-	-
Black Hills Store(P)	3	-	-	-	-	-	-	-	-	-	-
Black Hills Store(S)	(3)	-	-	-	-	-	-	-	-	-	-
BPA Spring Ex (P)	6	6	6	6	6	6	6	6	6	-	-
BPA Spring Ex (S)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	-	-
BPA Summer Ex (P)	14	14	14	14	14	14	14	14	14	-	-
BPA Summer Ex (S)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	-	-
CSPE	10	9	9	9	-	-	-	-	-	-	-
Deseret Annual	248	154	-	-	-	-	-	-	-	-	-
Deseret Expansion	27	14	-	-	-	-	-	-	-	-	-
Deseret NF	50	23	-	-	-	-	-	-	-	-	-
Gem State	6	6	6	6	6	6	6	6	6	6	6
Grant County	10	10	10	10	10	10	10	10	10	10	10
GSLM	5	5	5	5	5	5	5	5	5	5	5
Idaho Load Control	0	0	0	0	0	0	0	0	0	0	0
Interruptible Rep	-	-	-	-	-	-	-	-	0	1	1
IPC	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
PGE Cove	3	1	1	1	1	1	1	1	1	1	1

QF Idaho	8	8	8	8	8	8	8	8	8	8	
QF NW	59	59	59	59	59	59	59	59	59	59	5
QF UPL	39	39	39	39	39	39	39	39	39	39	3
San Juan Unit 4	15	15	15	15	15	15	15	15	15	-	-
SCE Winter	5	5	5	4	-	-	-	-	-	-	-
So Idaho Ex (P)	92	92	92	92	92	92	92	92	92	92	9
So Idaho Ex (S)	(92)	(92)	(92)	(92)	(92)	(92)	(92)	(92)	(92)	(92)	(9
Tri-State Basic	33	33	33	33	33	33	33	33	33	33	3
Tri-State Ex (P)	19	19	19	19	19	19	19	-	-	-	-
Tri-State Ex (S)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	-	-	-	-
USBR Greenspring	3	-	-	-	-	-	-	-	-	-	-
WWP Seasonal Ex (P)	3	3	3	3	3	3	3	3	-	-	-
WWP Seasonal Ex (S)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	-	-	-
WWP Summer Purchase	9	9	9	9	-	-	-	-	-	-	-
Purchased Power	756	589	397	396	374	374	374	355	352	318	317
Total Resources	8,354	8,166	7,901	7,912	8,067	8,148	8,120	8,125	8,140	8,145	8,142

Sales

APPA	23	-	-	-	-	-	-	-	-	-	-
Black Hills 1996	-	-	-	-	-	-	-	-	-	-	-
Black Hills Load	36	36	36	36	36	36	36	36	36	36	36
BPA Wind Sale											
Canadian Entitlement	0	0	0	0	0	0	0	0	0	0	0
CDWR	70	70	70	70	70	-	-	-	-	-	-
Cheyenne	109	-	-	-	-	-	-	-	-	-	-
Citizens Power											
Clark County PUD	142	102	-	-	-	-	-	-	-	-	-
Clark-FW											
Clark-WT											
Colockum	23	23	23	12	-	-	-	-	-	-	-
Cowlitz-BHP	19	19	8	-	-	-	-	-	-	-	-
EWEB	24	-	-	-	-	-	-	-	-	-	-
Green Mountain											
Hinson	76	-	-	-	-	-	-	-	-	-	-
Hurricane Net Sale											
Interruptibles	311	311	311	311	311	311	311	311	311	311	311
Montana Sell Back											
Okanogan	4	3	-	-	-	-	-	-	-	-	-
Plains Electric G&T	24	-	-	-	-	-	-	-	-	-	-
PNGC	30	14	-	-	-	-	-	-	-	-	-
PSCol	132	132	132	132	132	132	132	132	132	132	132
Puget 2	120	120	120	99	-	-	-	-	-	-	-
Redding	42	36	36	36	36	36	36	36	-	-	-
SCE OWC	70	70	70	70	70	70	52	-	-	-	-
SCE Utah	70	70	70	70	70	70	52	-	-	-	-
Sierra 1	75	75	75	75	75	75	75	75	75	75	75
Sierra 2	53	53	53	53	53	53	53	53	-	-	-
SMUD	40	40	40	40	40	40	40	40	40	-	-
Springfield	24	24	24	24	24	24	24	24	24	-	-
Springfield II	17	17	11	-	-	-	-	-	-	-	-
UMPA 1	5	5	5	5	5	2	-	-	-	-	-
UMPA 2	7	8	9	10	10	10	10	10	10	10	10
WAPA 1	43	35	35	35	35	-	-	-	-	-	-
WAPA 2	64	64	64	64	64	-	-	-	-	-	-
Total Sales	1,866	1,535	1,400	1,350	1,240	1,069	1,031	907	815	731	731

Appendix C

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Power Purchases:					
2	American Electric	OS		NA	NA	NA
3	American Electric	SF		NA	NA	NA
4	American Hunter Electric	OS		NA	NA	NA
5	American Hunter Electric	SF		NA	NA	NA
6	Anaheim, City of	OS		NA	NA	NA
7	Anaheim, City of	SF		NA	NA	NA
8	Aquila Power Corp.	OS		NA	NA	NA
9	Aquila Power Corp.	SF		NA	NA	NA
10	Aquila Power Corp.	SF		NA	NA	NA
11	Arizona Power Pool Association	OS		NA	NA	NA
12	Arizona Power Pool Association	SF		NA	NA	NA
13	Arizona Public Service Company	LF		NA	NA	NA
14	Arizona Public Service Company	OS		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
							1
64,416				1,339,168		1,339,168	2
990,474				34,152,462		34,152,462	3
500				11,825		11,825	4
10,800				229,300		229,300	5
6,901				87,609		87,609	6
16,640				440,960		440,960	7
183,736				3,967,983		3,967,983	8
					26,180	26,180	9
1,380,458				38,384,942		38,384,942	10
970				13,860		13,860	11
800				32,400		32,400	12
12,850				211,029		211,029	13
132,983				3,479,817		3,479,817	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Arizona Public Service Company	SF		NA	NA	NA
2	Avista Energy, Inc.	OS		NA	NA	NA
3	Avista Energy, Inc.	SF		NA	NA	NA
4	Beaver City	LF		NA	NA	NA
5	Bell Mountain Power	LU		.3	.3	.3
6	Benton County Public Util. Dist. No. 1	OS		NA	NA	NA
7	Biomass One, Limited Partnership	LU		22.5	22.1	17.9
8	Birch Creek Hydro	LU		1.9	2.3	1.7
9	Black Hills Power & Light Company	LF		NA	NA	NA
10	Black Hills Power & Light Company	LU		NA	41.7	6.6
11	Black Hills Power & Light Company	SF		NA	NA	NA
12	Bogus Creek	LU		NA	NA	NA
13	Boise Cascade Corporation	OS		NA	NA	NA
14	Bonneville Power Administration	IF		1100	1100	1025
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
328,465				9,151,421		9,151,421	1
246,456				5,076,417		5,076,417	2
676,269				17,536,411		17,536,411	3
59				3,964		3,964	4
2,462			94,751	34,867		129,618	5
2,480				47,267		47,267	6
147,098			2,111,400	13,002,118		15,113,518	7
16,568			669,461	231,435		900,896	8
164,572				2,667,828		2,667,828	9
6,330			600,000		423,560	1,023,560	10
143,263				2,510,094		2,510,094	11
1,292				37,144		37,144	12
1,534				28,560		28,560	13
			73,920,000			73,920,000	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

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IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Bonneville Power Administration	IF		NA	NA	NA
2	Bonneville Power Administration	LF		22.5	20	20
3	Bonneville Power Administration	OS		NA	NA	NA
4	Bonneville Power Administration	SF		NA	NA	NA
5	Boston Power	LU		.07	.03	.03
6	Boyd, James	LU		.4	.5	.2
7	Buffalo, City of	LU		.2	.2	.2
8	California Dept. of Water Resources	OS		NA	NA	NA
9	California Dept. of Water Resources	SF		NA	NA	NA
10	California Independent System Operator	OS		NA	NA	NA
11	California Independent System Operator	SF		NA	NA	NA
12	California Power Exchange	OS		NA	NA	NA
13	California Power Exchange	SF		NA	NA	NA
14	CDM Hydro	LU		4.2	5.1	3.9
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
146,350				2,707,475		2,707,475	1
			123,672			123,672	2
590,052				10,473,591		10,473,591	3
3,462,781				50,248,348		50,248,348	4
529			4,736	35,041		39,777	5
2,766			26,954	179,742		206,696	6
1,756			5,735	37,421		43,156	7
94,239				1,356,433		1,356,433	8
551,497				10,235,435		10,235,435	9
171,767				2,006,042		2,006,042	10
690				9,164		9,164	11
202				1,405		1,405	12
18,729				543,879		543,879	13
36,915			1,485,937	516,809		2,002,746	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Central Oregon Irrigation District	LU		5.9	5.1	3.8
2	Chelan County Public Util. Dist. No. 1	LU		NA	NA	NA
3	Chelan County Public Util. Dist. No. 1	OS		NA	NA	NA
4	Chelan County Public Util. Dist. No. 1	SF		NA	NA	NA
5	Chevron Chemical	OS		NA	NA	NA
6	Cinergy Services Inc.	OS		NA	NA	NA
7	Cinergy Services Inc.	SF		NA	NA	NA
8	Cinergy Services Inc.	SF		NA	NA	NA
9	Citizens Lehman Power Sales	OS		NA	NA	NA
10	Citizens Lehman Power Sales	SF		NA	NA	NA
11	Clark County Public Utility District	AD		NA	NA	NA
12	CNG Energy Services Corp.	OS		NA	NA	NA
13	CNG Energy Services Corp.	SF		NA	NA	NA
14	Colorado Springs	OS		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	REVENUE Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
34,898			605,774	2,422,298		3,028,072	1
353,217					3,009,367	3,009,367	2
12,295				153,801		153,801	3
600				9,900		9,900	4
3,242				48,302		48,302	5
66,199				1,239,929		1,239,929	6
					332,640	332,640	7
310,800				11,623,979		11,623,979	8
60,947				1,361,233		1,361,233	9
237,025				5,327,870		5,327,870	10
11,048					-930,470	-930,470	11
400				13,620		13,620	12
72,400				1,972,720		1,972,720	13
2,395				42,193		42,193	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Columbia Storage Power Exchange	LF		NA	NA	NA
2	Commercial Energy Management	LU		.4	.5	.4
3	ConAgra Energy Services	OS		NA	NA	NA
4	ConAgra Energy Services	SF		NA	NA	NA
5	Constellation Power Source, Inc	OS		NA	NA	NA
6	Constellation Power Source, Inc	SF		NA	NA	NA
7	Cook Electric	AD		NA	NA	NA
8	Cook Inlet Energy Supply	OS		NA	NA	NA
9	Cook Inlet Energy Supply	SF		NA	NA	NA
10	Coral Power	OS		NA	NA	NA
11	Coral Power	SF		NA	NA	NA
12	Cowlitz County Public Util. Dist. No.1	OS		NA	NA	NA
13	Cowlitz County Public Util. Dist. No.1	SF		NA	NA	NA
14	Curtiss Livestock	LU		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	REVENUE: Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
188,397				728		728	1
3,132			132,510	27,394		159,904	2
6,200				165,440		165,440	3
110,775				2,217,190		2,217,190	4
11,360				189,720		189,720	5
97,600				2,920,740		2,920,740	6
-2,002					-153,000	-153,000	7
47,425				1,166,414		1,166,414	8
4,000				62,800		62,800	9
800				25,600		25,600	10
94,000				1,550,040		1,550,040	11
8,868				142,225		142,225	12
303				9,090		9,090	13
321				18,767		18,767	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Davis County Waste Management	LU		NA	NA	NA
2	Deschutes Valley Water District	LU		5.9	4.8	3.4
3	Deseret Generation & Trans. Coop.	LF		NA	NA	NA
4	Difani, Chris	LU		NA	NA	NA
5	Douglas County Public Util. Dist. No.1	LU		NA	NA	NA
6	Douglas County Public Util. Dist. No.1	OS		NA	NA	NA
7	Douglas County Public Util. Dist. No.1	SF		NA	NA	NA
8	DR Johnson Lumber Company	LU		8.6	11.1	7.8
9	Duke Energy Trading	OS		NA	NA	NA
10	Duke Energy Trading	SF		NA	NA	NA
11	Dupont Power Marketing Inc.	SF		NA	NA	NA
12	Eagle Point Irrigation	LU		.4	.8	.3
13	Edison Source	AD		NA	NA	NA
14	El Paso Electric Company	OS		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE				
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1,723				28,014		28,014	1
32,787			577,697	2,671,766		3,249,463	2
2,348,991				46,232,642		46,232,642	3
					4,691	4,691	4
277,679					2,235,220	2,235,220	5
82,406				906,794		906,794	6
9,541				265,958		265,958	7
62,664			783,495	5,032,266		5,815,761	8
28,829				624,858		624,858	9
1,279,663				36,899,607		36,899,607	10
102,000				2,135,400		2,135,400	11
3,062			42,728	260,914		303,642	12
					196,040	196,040	13
-10,692				28,281	-190,486	-162,205	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	El Paso Electric Company	AD		NA	NA	NA
2	El Paso Energy Marketing	OS		NA	NA	NA
3	El Paso Energy Marketing	SF		NA	NA	NA
4	Electric Clearinghouse, Inc.	OS		NA	NA	NA
5	Electric Clearinghouse, Inc.	SF		NA	NA	NA
6	Electric Clearinghouse, Inc.	SF		NA	NA	NA
7	Energy Services, Inc.	AD		NA	NA	NA
8	Engage Energy US, L.P.	OS		NA	NA	NA
9	Engage Energy US, L.P.	SF		NA	NA	NA
10	Englehard Power Marketing, Inc.	OS		NA	NA	NA
11	Englehard Power Marketing, Inc.	SF		NA	NA	NA
12	Enron Power Marketing, Inc.	OS		NA	NA	NA
13	Enron Power Marketing, Inc.	SF		NA	NA	NA
14	Enserch Energy Services	OS		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	REVENUE: Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
-16,416					-221,400	-221,400	1
23,648				562,902		562,902	2
77,205				2,127,620		2,127,620	3
50,314				792,022		792,022	4
					307,000	307,000	5
522,649				11,858,962		11,858,962	6
401					6,400	6,400	7
9,025				248,491		248,491	8
508,050				13,077,429		13,077,429	9
400				6,400		6,400	10
93,110				2,256,985		2,256,985	11
287,023				5,638,086		5,638,086	12
1,415,493				34,435,065		34,435,065	13
26,336				469,208		469,208	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Enserch Energy Services	SF		NA	NA	NA
2	Entergy Power, Inc.	AD		NA	NA	NA
3	Entergy Power, Inc.	SF		NA	NA	NA
4	E'Prime Inc.	OS		NA	NA	NA
5	E'Prime Inc.	SF		NA	NA	NA
6	Equitable Power Services Co.	OS		NA	NA	NA
7	Equitable Power Services Co.	SF		NA	NA	NA
8	Eugene Water & Electric Board	OS		NA	NA	NA
9	Eugene Water & Electric Board	SF		NA	NA	NA
10	Falls Creek	LU		2.6	3.2	1.1
11	Farmers Irrigation	LU		4.1	3.2	2.1
12	Farmington, City of	OS		NA	NA	NA
13	Fery, Loyd	LU		NA	NA	NA
14	Fillmore City	LF		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
213,600				6,390,866		6,390,866	1
-6,640					-142,960	-142,960	2
21,600				501,960	549,120	1,051,080	3
23,800				509,100		509,100	4
51,800				1,711,200		1,711,200	5
7,200				162,500		162,500	6
12,800				325,260		325,260	7
27,569				716,564		716,564	8
14,820				393,688		393,688	9
16,624			189,456	1,280,837		1,470,293	10
24,282			354,575	1,891,580		2,246,155	11
870				18,370		18,370	12
273				15,982		15,982	13
79				8,473		8,473	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Galesville Dam	LU		.8	1.3	.8
2	Garland Canal	LU		1.6	1.6	1.1
3	General Chemical Company	OS		NA	NA	NA
4	Georgetown Power	LU		.3	.4	.3
5	Glendale, City of	AD		NA	NA	NA
6	Glendale, City of	SF		NA	NA	NA
7	Grand Valley Rural Power	LF		NA	NA	NA
8	Grant County Public Utility Dist. No.2	LF		NA	NA	NA
9	Grant County Public Utility Dist. No.2	LU		NA	NA	NA
10	Grant County Public Utility Dist. No.2	LU		NA	NA	NA
11	Grant County Public Utility Dist. No.2	OS		NA	NA	NA
12	Grant County Public Utility Dist. No.2	SF		NA	NA	NA
13	Great Salt Lake Minerals	LU		NA	NA	NA
14	Heber Light & Power	LF		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
8,558			86,492	777,858		864,350	1
10,631			115,436	299,917		415,353	2
3,373				50,249		50,249	3
3,020			119,555	42,282		161,837	4
-50					-775	-775	5
24,638				521,884		521,884	6
113				9,073		9,073	7
87,600				3,066,000		3,066,000	8
890,274					5,211,412	5,211,412	9
548,864					3,314,271	3,314,271	10
248,323				4,603,407		4,603,407	11
8,240				157,071		157,071	12
34,917				712,216		712,216	13
1,988				115,935		115,935	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Hermiston Generating Company, L.P.	LU		218.2	234.9	201.5
2	Hinson Power Company, Inc.	SF		NA	NA	NA
3	Hurricane, City of	LF		NA	NA	NA
4	Idaho Falls, City of	LU		NA	NA	NA
5	Idaho Falls, City of	OS		NA	NA	NA
6	Idaho Power Company	OS		NA	NA	NA
7	Idaho Power Company	SF		NA	NA	NA
8	Idaho Power Company	SF		NA	NA	NA
9	Illinova Power Marketing, Inc.	OS		NA	NA	NA
10	Illinova Power Marketing, Inc.	SF		NA	NA	NA
11	Imperial Irrigation District	OS		NA	NA	NA
12	Imperial Irrigation District	SF		NA	NA	NA
13	Ingram Warm Springs Ranch	LU		.4	.3	.2
14	Intermountain Power Project	LU		64	64	64
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	REVENUE Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1,701,968			39,004,356	27,195,301	-468,148	65,731,509	1
					160,911	160,911	2
863				27,587		27,587	3
65,015				2,277,788		2,277,788	4
4,320				60,480		60,480	5
121,071				3,163,673	-792,518	2,371,155	6
					209,440	209,440	7
1,268,871				30,120,635		30,120,635	8
358				76,538		76,538	9
308,142				5,621,099		5,621,099	10
8,445				202,915		202,915	11
18,400				431,600		431,600	12
3,240			116,076	40,135		156,211	13
539,798			20,947,200	6,815,353		27,762,553	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Kennecott	LU		NA	NA	NA
2	Koch Power Services, Inc.	OS		NA	NA	NA
3	Koch Power Services, Inc.	SF		NA	NA	NA
4	Lacomb Irrigation	LU		.8	.5	.3
5	Lake Siskiyou	LU		4	4.8	3.1
6	LG&E Power Marketing Inc.	OS		NA	NA	NA
7	LG&E Power Marketing Inc.	SF		NA	NA	NA
8	Los Alamos County	OS		NA	NA	NA
9	Los Angeles, City of	OS		NA	NA	NA
10	Los Angeles, City of	SF		NA	NA	NA
11	Los Angeles, City of	SF		NA	NA	NA
12	Luckey, Paul	LU		NA	NA	NA
13	Marsh Valley Hydro Electric Company	LU		1	1.4	1
14	McMinnville Water and Light	OS		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE				
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
32,592				701,665		701,665	1
21,895				427,979		427,979	2
236,175				7,818,355		7,818,355	3
3,195			23,890	194,193		218,083	4
31,452			378,246	2,613,859		2,992,105	5
21,904				463,860		463,860	6
44,530				1,236,348		1,236,348	7
125				3,250		3,250	8
128,387				3,563,149		3,563,149	9
49,628				1,223,543		1,223,543	10
103,115				3,947,076		3,947,076	11
333				23,857		23,857	12
8,819			357,081	123,373		480,454	13
711				31,882		31,882	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	MidAmerican Energy Company	AD		NA	NA	NA
2	Middlefork Irrigation District	LU		3	3	3
3	Mieco, Inc.	SF		NA	NA	NA
4	Mink Creek Hydro	LU		1.4	1.6	1.4
5	Minnesota Power	OS		NA	NA	NA
6	Modesto Irrigation District	OS		NA	NA	NA
7	Modesto Irrigation District	SF		NA	NA	NA
8	Montana Power Company	OS		NA	NA	NA
9	Montana Power Company	SF		NA	NA	NA
10	Morgan City	LF		NA	NA	NA
11	Morgan Stanley Capital Group Inc.	OS		NA	NA	NA
12	Morgan Stanley Capital Group Inc.	SF		NA	NA	NA
13	Morgan Stanley Capital Group Inc.	SF		NA	NA	NA
14	Mountain Energy	LU		.01	.01	.01
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	REVENUE: Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
4,284					67,139	67,139	1
24,603			184,569	1,754,246		1,938,815	2
800				48,000		48,000	3
12,141			473,322	169,967		643,289	4
2,750				52,761		52,761	5
31,317				834,419		834,419	6
35,370				966,013		966,013	7
88,787				1,931,894		1,931,894	8
129,045				3,369,591		3,369,591	9
29				730		730	10
2,400				58,800		58,800	11
					96,000	96,000	12
52,737				1,381,573		1,381,573	13
93			952	6,420		7,372	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Mt. Poso Cogeneration Company	SF		NA	NA	NA
2	Municipal Energy Agency of Nebraska	OS		NA	NA	NA
3	Municipal Energy Agency of Nebraska	SF		NA	NA	NA
4	Murray City	LF		NA	NA	NA
5	National Gas & Electric L.P.	OS		NA	NA	NA
6	Nebraska Public Power District	OS		NA	NA	NA
7	Nebraska Public Power District	SF		NA	NA	NA
8	Nephi City	LF		NA	NA	NA
9	Nevada Power Company	OS		NA	NA	NA
10	Nevada Power Company	SF		NA	NA	NA
11	New Energy Ventures, LLC	SF		NA	NA	NA
12	Nicholson Sunnybar Ranch	LU		.3	.4	.3
13	Noram Energy Services, Inc.	OS		NA	NA	NA
14	Noram Energy Services, Inc.	SF		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	REVENUE Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
6,265				128,433		128,433	1
2,310				70,230		70,230	2
5,380				139,340		139,340	3
144				7,423		7,423	4
1,600				36,000		36,000	5
23,480				720,569		720,569	6
15,200				447,200		447,200	7
19				1,702		1,702	8
84,891				2,496,817		2,496,817	9
4,400				205,200		205,200	10
291,594				6,627,671		6,627,671	11
2,827			111,450	40,431		151,881	12
68,615				1,336,560		1,336,560	13
506,239				13,178,983		13,178,983	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	North Fork Sprague	LU		.6	.9	.5
2	Northern California Power Agency	OS		NA	NA	NA
3	Northern California Power Agency	SF		NA	NA	NA
4	Northern States Power	SF		NA	NA	NA
5	NP Energy Inc.	OS		NA	NA	NA
6	NP Energy Inc.	SF		NA	NA	NA
7	O.J. Power Company	LU		.1	.2	.1
8	Odell Creek	LU		.01	.02	.01
9	Okanogan County Publiic Utility Dist	OS		NA	NA	NA
10	Omaha Public Power District	OS		NA	NA	NA
11	Omaha Public Power District	SF		NA	NA	NA
12	Ormsby, Leslie	LU		NA	NA	NA
13	Pacific Gas & Electric Company	OS		NA	NA	NA
14	Pacific Gas & Electric Company	SF		NA	NA	NA
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	REVENUE Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
3,939			62,984	332,446		395,430	1
5,706				115,810		115,810	2
29,440				1,295,240		1,295,240	3
35,453				718,558		718,558	4
-83,960				430,560	-2,899,540	-2,468,980	5
1,407,965				31,793,490	2,952,100	34,745,590	6
1,120			41,613	15,676		57,289	7
81			986	5,585		6,571	8
1,186				11,493		11,493	9
1,950				94,000		94,000	10
13				286		286	11
13				730		730	12
7,952				165,675		165,675	13
172,276				2,639,522		2,639,522	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Pacific Gas & Electric Energy Trading	OS		NA	NA	NA
2	Pacific Gas & Electric Energy Trading	SF		NA	NA	NA
3	Pacific Northwest Generating Coop	OS		NA	NA	NA
4	Pacific Northwest Generating Coop	SF		NA	NA	NA
5	Pancheri, Inc.	LU		.01	.01	.01
6	Panenergy	AD		NA	NA	NA
7	Pasadena, City of	OS		NA	NA	NA
8	PECO Energy	OS		NA	NA	NA
9	PECO Energy	SF		NA	NA	NA
10	Phibro Inc.	OS		NA	NA	NA
11	Phibro Inc.	SF		NA	NA	NA
12	Plains Electric Generation and Trans	OS		NA	NA	NA
13	Plains Electric Generation and Trans	SF		NA	NA	NA
14	Platte River Power Authority	OS		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
61,168				1,189,565		1,189,565	1
418,795				12,241,728		12,241,728	2
800				12,304		12,304	3
10,400				344,240		344,240	4
98			2,870	1,741		4,611	5
144					2,208	2,208	6
2,990				41,360		41,360	7
55,735				867,379		867,379	8
253,732				6,499,169		6,499,169	9
-3,232				6,400	-80,698	-74,298	10
64,832				1,721,564		1,721,564	11
15,725				268,780		268,780	12
13,520				186,728		186,728	13
12,817				179,375		179,375	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Platte River Power Authority	SF		NA	NA	NA
2	Portland General Electric Company	LF		NA	NA	NA
3	Portland General Electric Company	OS		NA	NA	NA
4	Portland General Electric Company	SF		NA	NA	NA
5	Powerex	OS		NA	NA	NA
6	Powerex	SF		NA	NA	NA
7	Preston City Hydro	LU		.4	.4	.4
8	Provo City	LF		NA	NA	NA
9	Public Service Company of Colorado	OS		NA	NA	NA
10	Public Service Company of Colorado	SF		NA	NA	NA
11	Public Service Company of New Mexico	OS		NA	NA	NA
12	Public Service Company of New Mexico	SF		NA	NA	NA
13	Puget Sound Power & Light Company	OS		NA	NA	NA
14	Puget Sound Power & Light Company	SF		NA	NA	NA
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
7,161				133,098		133,098	1
24,000					245,450	245,450	2
150,645				3,601,986		3,601,986	3
425,423				9,484,360	-692,350	8,792,010	4
224,129				6,688,168		6,688,168	5
491,953				11,147,409	375,938	11,523,347	6
3,128			110,943	43,791		154,734	7
115				9,934		9,934	8
56,255				1,292,225		1,292,225	9
232,313				5,795,213		5,795,213	10
318,203				7,679,736		7,679,736	11
343,550				6,542,877		6,542,877	12
221,743				4,367,932		4,367,932	13
338,829				7,281,241		7,281,241	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	QST Energy Trading inc.	OS		NA	NA	NA
2	QST Energy Trading inc.	SF		NA	NA	NA
3	Questar Energy Trading	OS		NA	NA	NA
4	Ralphs Ranches, Inc.	LU		NA	NA	NA
5	Redding, City of	LF		50	49	39
6	Redding, City of	OS		NA	NA	NA
7	Redding, City of	SF		NA	NA	NA
8	Riverside, City of	OS		NA	NA	NA
9	Rocky Mountain Generation Cooperative	OS		NA	NA	NA
10	Rocky Mountain Generation Cooperative	SF		NA	NA	NA
11	Rousch, Neil	LU		NA	NA	NA
12	Royal Oak	LU		NA	NA	NA
13	Sacramento Municipal Utility District	OS		NA	NA	NA
14	Sacramento Municipal Utility District	SF		NA	NA	NA
	Total					

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9. Footnote entnes as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	REVENUE Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
47,009				610,322		610,322	1
23,600				501,300		501,300	2
400				9,300		9,300	3
335				24,007		24,007	4
370,733			9,288,500	5,983,206	1,425,085	16,696,791	5
2,470				45,305		45,305	6
19,600				477,680		477,680	7
4,016				64,211		64,211	8
58,727				891,486		891,486	9
217,478				3,524,644		3,524,644	10
433				25,345		25,345	11
					605,000	605,000	12
64,386				1,099,653		1,099,653	13
27,600				536,000		536,000	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Salt River Project	OS		NA	NA	NA
2	Salt River Project	SF		NA	NA	NA
3	San Diego Gas & Electric	OS		NA	NA	NA
4	San Diego Gas & Electric	SF		NA	NA	NA
5	Santa Clara, City of	OS		NA	NA	NA
6	Santa Clara, City of	SF		NA	NA	NA
7	Santiam Water Control District	LU		.2	.2	.2
8	SaskPower	AD		NA	NA	NA
9	Scana Energy Marketing, Inc.	OS		NA	NA	NA
10	Scana Energy Marketing, Inc.	SF		NA	NA	NA
11	Seattle City Light	OS		NA	NA	NA
12	Seattle City Light	SF		NA	NA	NA
13	Sempra Energy Trading Corp	OS		NA	NA	NA
14	Sempra Energy Trading Corp	SF		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
287,702				6,306,435		6,306,435	1
387,204				9,560,173		9,560,173	2
4,721				62,524		62,524	3
78,701				1,411,221		1,411,221	4
79,583				1,626,439		1,626,439	5
325,382				7,756,399		7,756,399	6
1,440			13,632	89,301		102,933	7
-120					-1,440	-1,440	8
1,600				31,800		31,800	9
32,800				746,300		746,300	10
40,779				901,878		901,878	11
23,196				683,441		683,441	12
2,121				249,787	-299,148	-49,361	13
139,998				3,784,843	281,500	4,066,343	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sierra Pacific Power Company	OS		NA	NA	NA
2	Sierra Pacific Power Company	SF		NA	NA	NA
3	Slate Creek	LU		2.5	2.3	1.4
4	Snohomish Public Utility District	OS		NA	NA	NA
5	Snohomish Public Utility District	SF		NA	NA	NA
6	Southern California Edison Company	LF		422	NA	NA
7	Southern California Edison Company	OS		NA	NA	NA
8	Southern Energy Marketing Co.	OS		NA	NA	NA
9	Southern Energy Marketing Co.	SF		NA	NA	NA
10	Spanish Fork City	LF		NA	NA	NA
11	Springville City	LF		NA	NA	NA
12	Statoil Energy , Inc.	OS		NA	NA	NA
13	Statoil Energy , Inc.	SF		NA	NA	NA
14	Stauffer Dry Creek	LU		.6	1	.4
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	REVENUE: Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
14,064				295,631		295,631	1
158,105				3,571,182		3,571,182	2
15,646			279,402	972,316		1,251,718	3
61,360				1,564,466		1,564,466	4
79,245				1,913,889		1,913,889	5
			7,553,800	863,941		8,417,741	6
6,395				155,143		155,143	7
84,250				1,526,152		1,526,152	8
658,775				15,748,390		15,748,390	9
49				4,013		4,013	10
45				3,606		3,606	11
5,807				505,405	-424,253	81,152	12
507,307				14,722,879		14,722,879	13
4,835			140,988	98,023		239,011	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Strawberry Electric Service District	OS		NA	NA	NA
2	Sunnyside	LU		40.7	52.9	38.7
3	Tacoma City Light	OS		NA	NA	NA
4	Tacoma City Light	SF		NA	NA	NA
5	Tenaska Power Services Company	OS		NA	NA	NA
6	Teton Generating Station	AD		NA	NA	NA
7	Thayne Ranch Hydro	LU		.3	.3	.3
8	The Power Company of America	OS		NA	NA	NA
9	The Power Company of America	SF		NA	NA	NA
10	The Power Company of America	SF		NA	NA	NA
11	Tillamook People's Utility District	OS		NA	NA	NA
12	Tractebel Energy Marketing, Inc.	OS		NA	NA	NA
13	Tractebel Energy Marketing, Inc.	SF		NA	NA	NA
14	TransAlta Energy Marketing Corp.	OS		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year of Report Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	REVENUE Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
19				1,382		1,382	1
356,182			9,782,725	7,604,812		17,387,537	2
15,164				386,213		386,213	3
5,880				142,051		142,051	4
112				3,136		3,136	5
					893	893	6
2,361			24,534	75,634		100,168	7
12,644				288,829	-727,060	-438,231	8
					175,560	175,560	9
293,963				6,141,346		6,141,346	10
110				1,105		1,105	11
29,200				477,600		477,600	12
305,250				8,987,020		8,987,020	13
3,299				288,498		288,498	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	TransAlta Energy Marketing Corp.	SF		NA	NA	NA
2	TransCanada Power	OS		NA	NA	NA
3	Tri-State Generation & Transmission	LF		50	48.8	47.3
4	Tri-State Generation & Transmission	OS		NA	NA	NA
5	Tucson Electric Power	OS		NA	NA	NA
6	Tucson Electric Power	SF		NA	NA	NA
7	Turlock Irrigation District	OS		NA	NA	NA
8	United States Bureau of Reclamation	LU		NA	NA	NA
9	Utah Assoc. Municipal Power Systems	OS		NA	NA	NA
10	Utah Municipal Power Agency	OS		NA	NA	NA
11	Utah Municipal Power Agency	SF		NA	NA	NA
12	Valero Power Services Company	OS		NA	NA	NA
13	Valero Power Services Company	SF		NA	NA	NA
14	Vantus Energy	AD		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
164,790				3,751,825		3,751,825	1
400				7,200		7,200	2
292,335			6,312,000	4,496,112		10,808,112	3
8,824				193,969		193,969	4
123,132				2,558,661		2,558,661	5
40,000				1,634,200		1,634,200	6
1,080				21,109		21,109	7
52,680				740,420		740,420	8
4,532				100,632		100,632	9
14,161				235,635		235,635	10
959				25,195		25,195	11
800				14,000		14,000	12
-11,200				-14,560		-14,560	13
10,410					-407,680	-407,680	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Vastar Power Marketing	SF		NA	NA	NA
2	Vitol Gas & Electric	OS		NA	NA	NA
3	Vitol Gas & Electric	SF		NA	NA	NA
4	Vitol Gas & Electric	SF		NA	NA	NA
5	Walla Walla, City of	LU		1.9	1.8	1.8
6	Warm Springs Forest Products	OS		NA	NA	NA
7	Warm Springs Power Enterprises	LU		19.6	15.8	9.4
8	Washington City	LF		NA	NA	NA
9	Washington Water Power Company	AD		NA	NA	NA
10	Washington Water Power Company	LF		150	150	82.5
11	Washington Water Power Company	OS		NA	NA	NA
12	Washington Water Power Company	SF		NA	NA	NA
13	West Kootenay Power & Light Company	OS		NA	NA	NA
14	West Plains	OS		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
2,800				56,700		56,700	1
26,577				582,816		582,816	2
					165,600	165,600	3
118,673				2,905,433		2,905,433	4
15,317			133,148	1,503,820		1,636,968	5
4				88		88	6
94,084			2,048,592	6,454,832		8,503,424	7
33				1,904		1,904	8
					750	750	9
81,600			1,732,500	1,897,200		3,629,700	10
347,412				7,891,108		7,891,108	11
572,362				13,601,690		13,601,690	12
-4,911				5,410	-84,996	-79,586	13
3,680				82,640		82,640	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Western Area Power Administration	OS		NA	NA	NA
2	Western Area Power Administration	SF		NA	NA	NA
3	Western Resources	OS		NA	NA	NA
4	Whitmore Oxygen	OS		NA	NA	NA
5	Whitney, A. C.	LU		NA	NA	NA
6	Wiggins, Duane	LU		NA	NA	NA
7	Williams Energy Services Company	OS		NA	NA	NA
8	Williams Energy Services Company	SF		NA	NA	NA
9	Williams Energy Services Company	SF		NA	NA	NA
10	Yakima Tieton	LU		1	.4	.1
11						
12	Power Exchanges:					
13	Anaheim, City of	EX	T-5	NA	NA	NA
14	Arizona Public Service Company	EX	306	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.

For requirements RQ purchases and any type of services involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column(d), the average monthly non- coincident peak (NCP) demanding in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in rendered to the respondent. Report in column (h), and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.

5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.

9. Footnote entnes as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	REVENUE: Demand Charges ($) (j)	REVENUE: Energy Charges ($) (k)	REVENUE: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
189 149				3,558,192		3,558,192	1
81 606				1,939,947		1,939,947	2
300				25,500		25,500	3
1.383				26,739		26,739	4
1				68		68	5
44				2,582		2,582	6
-879				939,212	-581,460	357,752	7
					7,488	7,488	8
384.404				11,488,105		11,488,105	9
7,026			62,572	647,119		709,691	10
							11
							12
	2,737	2,670					13
	224,508	301,260			-844,272	-844,272	14
39.774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Ashland, City of	EX	353	NA	NA	NA
2	Black Hills Power & Light Company	EX	246	NA	NA	NA
3	Bonneville Power Administration	EX	160	NA	NA	NA
4	Bonneville Power Administration	EX	237	NA	NA	NA
5	Bonneville Power Administration	EX	256	NA	NA	NA
6	Bonneville Power Administration	EX		NA	NA	NA
7	Bonneville Power Administration	EX	347	NA	NA	NA
8	Chelan County Public Util. Dist. No. 1	EX	160	NA	NA	NA
9	Clark County Public Utility District	EX	417	NA	NA	NA
10	Colockum Transmission Company	EX	160	NA	NA	NA
11	Colorado Public Service Company	EX	319	NA	NA	NA
12	Cowlitz County Public Util, Dist. No.1	EX	160	NA	NA	NA
13	Douglas County Public Util. Dist. No.1	EX	160	NA	NA	NA
14	Emerald Peoples Utility District	EX	351	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
	2,097	61			73,346	73,346	1
	12,885	21,831			-199,565	-199,565	2
	359,768	221,180			-28,864	-28,864	3
					37,683	37,683	4
	78,915	147,504			-1,420,094	-1,420,094	5
	1,005,332	1,005,332			-11,437,208	-11,437,208	6
	3,531,140	3,554,577					7
	1,261	9,525					8
	920,213				14,369,678	14,369,678	9
	15,964	205,580			-61,704	-61,704	10
	5,310						11
	224,519	247,257					12
	1,020	7,440					13
		70			-1,741	-1,741	14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Grant County Public Utility Dist. No.2	EX	160	NA	NA	NA
2	Idaho Power Company	EX	T-12	NA	NA	NA
3	Montana Power Company	EX	T-12	NA	NA	NA
4	Okanogan County Public Utility Distrit	EX	T-12	NA	NA	NA
5	Pacific Gas & Electric Company	EX	83	NA	NA	NA
6	Portland General Electric Company	EX	T-12	NA	NA	NA
7	Redding, City of	EX	364	NA	NA	NA
8	Sierra Pacific Power Company	EX	T-5	NA	NA	NA
9	Tri-State Generation & Transmission	EX	319	NA	NA	NA
10	United States Bureau of Reclamation	EX	67	NA	NA	NA
11	Washington Water Power Company	EX	366	NA	NA	NA
12	Washington Water Power Company	EX	376	NA	NA	NA
13	Washington Water Power Company	EX	T-12	NA	NA	NA
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

In column (c), identify the FERC Rate Schedule Number or tariffs, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		REVENUE			Total (j+k+l) of Settlement ($) (m)	Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)		
	10,609	27,267					1
	336,902	254,503					2
	13,745						3
	535	486			-2,621	-2,621	4
		150					5
	102,739	101,849					6
	136,706				2,651,132	2,651,132	7
		100					8
	165,552	147,100			-30,228	-30,228	9
		5,000					10
	27,150	25,650			16,500	16,500	11
		20					12
	2,002						13
							14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	System Deviation			NA	NA	NA
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

PURCHASED POWER(Account 555) (Continued)
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AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	REVENUE: Demand Charges ($) (j)	REVENUE: Energy Charges ($) (k)	REVENUE: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
-8,314							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
39,774,761	7,181,609	6,286,412	181,239,295	874,968,606	16,410,623	1,072,618,524	

Tapping the Power of Wind

In the windswept rimrock of southeastern Wyoming, PacifiCorp is building the largest wind plant in the West outside of California. The Wyoming Wind Energy Project will provide clean, renewable energy to customers and advance the science of generating wind power in the most environmentally responsible way.

The project, located on blustery Foote Creek Rim between Laramie and Rawlins, Wyo., will be home to 69 wind turbines capable of generating 41.4 megawatts of electricity. That's enough power to serve 15,000 to 25,000 customers, depending on wind conditions.

PacifiCorp, based in Portland, Ore., owns 80 percent of the $60 million project, and the Eugene Water and Electric Board (EWEB) of Eugene, Ore., owns the balance. The Bonneville Power Administration will buy 15 megawatts of the plant's output, with PacifiCorp and EWEB buying the remaining power. The project is expected to generate electricity by late 1998 or early 1999.

The Wyoming Wind Project will give a nationwide boost to renewable energy generation. U.S. Energy Secretary Federico Pena noted, "Projects like this are pushing wind energy into the mainstream of electricity generation in the United States, while contributing to a cleaner environment in the Rockies and Pacific Northwest."

A unique project in a highly energized place

Located at one of the windiest sites in America, the Wyoming project stands out from other wind plants. With average winds of 25 mph, the site has higher sustained winds than most other projects, where winds average 15 to 20 mph. Higher winds have the potential to generate more electricity.

The temperature range also is more extreme than most wind plant sites, since Wyoming winter temperatures can drop to 30° below zero. The equipment has been adapted for cold weather, and scientists and energy experts will study these conditions to determine the impacts on technology and energy production.

The Wyoming Wind Energy Project also is designed to be as environmentally friendly as possible. Independent consultants conducted a year-long study to minimize impacts on birds and wildlife, and the studies will continue while the project is operating. PacifiCorp chose turbines with tubular towers rather than lattice bases to protect birds from perching on the equipment, yet workers can still

Facts about Wyoming Wind Energy Project

Owners: PacifiCorp and Eugene Water and Electric Board

Developer: SeaWest of San Diego, Calif.

Power Purchasers: Bonneville Power Adminstration, PacifiCorp and EWEB

Project Cost: $60 million

Size of Project: 41.4 megawatts

Location: between Laramie and Rawlins, Wyoming

Acres: 2,156 acres

Electrical facilities: 28.8-mile transmission line and a substation

Groundbreaking: Sept. 1997

Completion Date: Late 1998 or early 1999

Equipment Used: 600-kilowatt turbines by Mitsubishi Heavy Industries

Jobs: 130 construction jobs; 8 permanent jobs climb interior ladders to safely maintain equipment during the cold winters.

To avoid the birds' flight corridor, the project was located away from the rimrock's edge. Wires and other electrical distribution equipment will be underground to avoid bird contact. And by using larger turbines than have been traditionally used at wind projects, fewer machines are needed to produce the same amount of energy.

The wind machines will stand 131 feet high and will catch the wind with slender blades. While the wind project will be confined to 2,156 acres, ranchers will continue to use most of the land for grazing.

An old idea is reborn

The Wyoming Wind Energy Project will use state-of-the-art technology while harnessing a form of energy that dates back centuries. Windmills have pumped water and ground grain for hundreds of years. Although less widely used as electric power generators, windmills often were found on remote U.S. farms from the early 1900s to 1930s. But wind technology at the time could not compete with inexpensive fossil fuels, and their use dwindled.

Wind plants re-emerged in the 1980s as technology improved and costs declined. PacifiCorp participated in the emerging research and persisted through early technological setbacks. PacifiCorp has invested in two successful wind plants near Altamont Pass, Calif., and is expanding its efforts with the Wyoming Wind Energy Project – the third generation of wind technology.

Today, wind power accounts for less than two percent of the electric generation mix in the United States. Yet wind is among the most affordable forms of renewable energy. With federal incentives, wind power costs about 4.5 cents per kilowatt hour, while solar energy costs three to four times more. However, wind power costs are higher than more traditional forms of generation such as coal and gas, which range from 3.2 cents to 3.8 cents per kilowatt hour.

Renewable resources balance other generation

Using wind power has environmental and social benefits. Wind produces no air emissions. Every kilowatt hour of wind power offsets one to two pounds of carbon dioxide emissions from coal-and gas-fired plants. This is significant, since a number of scientists believe that carbon dioxide emissions contribute to global warming.

Wind plants also bring economic benefits. PacifiCorp and EWEB are leasing land for the project from local ranchers, the Bureau of Land Management and the state of Wyoming. Even so, much of that land will continue to be available for other uses such as cattle grazing. The plant will employ about 130 people during construction and about eight permanent employees. And tax revenues from the wind plant will fuel local schools and community development efforts.

Wind power also allows utilities to diversify their resource mix and to gain experience using alternative energy. By adding more turbines, wind plants can easily be expanded to meet a utility's growing energy needs (the Wyoming Wind Energy Project is permitted up to 68 megawatts).

As with every energy resource, wind power has trade-offs. Wind is an intermittent energy resource; when the wind does not blow, energy is not produced. Electricity from the Wyoming wind project will be integrated into the PacifiCorp system, which also includes power from coal, hydroelectric, gas and geothermal plants. With its diverse resource mix, PacifiCorp can ensure its customers access to reliable, low-cost electricity.

Renewable resources such as the Wyoming Wind Energy Project offer PacifiCorp the opportunity to meet customers' needs. Research shows that many customers value the environmental benefits of electricity generated by renewable energy. PacifiCorp plans to offer customers the choice of purchasing more of their power from renewable energy sources.

PacifiCorp's other renewable resources include a 24-megawatt geothermal plant in Utah and small hydro projects throughout the West. It has invested $1.3 million in Solar II, the world's largest solar energy plant, located in the Mojave Desert. PacifiCorp also has solar energy projects in Oregon, Wyoming and Utah. The company's support of renewable energy demonstrates its commitment to providing reliable, economical and environmentally friendly power to its customers.

Recycled Paper

9/97

PACIFICORP

For more information, please visit PacifiCorp's web site at www.pacificorp.com or contact Corporate Communications, (503) 464-6316.

Foote Creek I-Generation Analysis
Total Project Share

	Projected MWH	Actual MWH	Variance MWH	Variance %
Jan-99	16,600	Project Undergoing testing		
Feb-99	13,650			
Mar-99	14,100			
Apr(1-21)	9,277			
Apr(22-30)	3,373	4,690	1,317	28.1%
May-99	9,750	11,468	1,718	15.0%
Jun-99	10,100	8,956	(1,144)	-12.8%
Jul-99	10,200	7,179	(3,021)	-42.1%
Aug-99	9,400	7,194	(2,206)	-30.7%
Sep-99	10,750	8,982	(1,768)	-19.7%
Oct-99	14,450	14,462	12	0.1%
Forecast 11/1999	16,300	**16,300**	**-**	**0.0%**
Forecast 12/1999	16,500	**16500**	**-**	**0.0%**
Total Full Commercial Year	154,450			
Partial Year Operation 1999	100,823	95,731	-5,092	-5.3%

PacifiCorp's

Annual Review

of

1998 Energy Efficiency Programs

in

State of Oregon

April 27, 1999

Table of Contents

List of Tables

SUMMARY

Provided herein is:

PacifiCorp's 1999 Annual Review of 1998 Energy Efficiency Programs

As requested, the Company has provided data on 1998 performance in the State of Oregon with respect to **RAMPP-5** goals by sector and program, and an explanation of variances from these goals.

Approach

The **1998 targets** are based on RAMPP-5, which was submitted to the Commission in December 1997 and acknowledged by the Oregon Commission in March 1999. Estimates of program cost-effectiveness are based on UM 551 methodology and initial 1998 estimates of savings, project costs, and actual program expenditures. The reported results are based on actual installations for the calendar year 1998.

Savings per unit are based on the Company's most recent evaluations. If no draft or final study is available, the Company has used existing deemed savings estimates. Realization rates were used from all the evaluations that were reviewed by the DSM Evaluation Advisory Group in November 1998, and finalized in March 1999.

Draft versions of 1997 evaluations are currently underway and will be distributed and sent to the DSM Evaluation Advisory Group this Spring. A meeting will then be scheduled for the group to review and discuss the draft evaluations.

Achievements

In 1998, Pacific Power (PacifiCorp) achieved a total of **36,825,065 KWh or 4.20Wa** in the State of Oregon. Of this total, **12,272,185 KWh or 1.40Wa** represented savings for Company programs and 24,552,880 KWh or 2.80 Mwa represented savings associated with NEEA programs. The total savings represents 235% of the Company goal. Company programs achieved 78% of the RAMPP-5 goal of 1.79 Mwa. Programs that delivered maximum savings for the least-cost continued to be the focus in 1998 as they were in 1997. Emphasis continued to be placed on innovative delivery methods and customer-financing of measures whenever possible in order to take advantage of lower interest rates

OPUC Requests (letter of 2/09/99)

Staff has asked the Company to provide the following information:

1. **Data on 1998 performance with respect to IRP targets, by sector and program and an explanation of variances, if any, from the targets. This information should be provided in the same table format as in previous years.**

This information is provided in the included table on page #4 in the format laid out by Staff. It includes an explanation of variances from energy savings targets, program penetration, saturation, and cost-effectiveness. Achieved results reported here are compared to the targets for 1998 established in RAMPP-5. RAMPP-5 was submitted to the Commission for its review in December 1997, and was acknowledged by the Commission in March 1999.

2. **A discussion of progress on each of the recommendations made by staff in the 1998 Annual Review of 1997 Programs.**

No recommendations were made by the OPUC staff.

3. **A description of proposed program improvements for 1999 and strategies to address variances identified above.**

These descriptions are discussed program-by-program hereafter. Each program discussion covers energy savings and cost-effectiveness, planned modifications, if any, to programs in 1999, and specific strategies, where applicable, to address variances between targets and achieved energy savings.

4. **For the residential sector, please tell us (1) how many energy audits you provided in 1998, single-family vs. multi-family, (2) the number of grants (rebates) and the dollar value of these grants provided in 1998, low-income recipient vs. other; and (3) the number of loans and the dollar value of these loans provided in 1998, low income recipients vs. other.**

PacifiCorp did energy audits on a total of 1,972 homes in Oregon in 1998. Of these, 757 were non-low income single-family, 1,004 were non-low income multi-family, 191 were low-income single-family, and 20 were low-income multi-family. PacifiCorp weatherized 656 Oregon homes in 1998, with total Company expenditures of $329,540. Loans to 17 households, amounting to $67,223, were made to non-low income residential customers for weatherization. There were 428 rebates given, in the amount of $76,652, to non-low income residential households for weatherization. There was 211 grants given, in the amount of $185,665 to low income residential households for weatherization.

PROGRAM OVERVIEW

In 1998, Pacific Power (PacifiCorp) achieved a total of **36,825,065 KWh or 4.20 MWa** of savings in the State of Oregon. Savings associated with Company programs totaled **12,272,185 KWh or 1.40 MWa** and represents 78% of the RAMPP-5 goal of **1.79 MWa**. The Northwest Energy Efficiency Alliance (NEEA) savings totaled **24,552,880 KWh** and is included in the overall total of **36,825,065 KWh**.

Table 2 below shows total savings by sector and market and achievement as a Percentage of the RAMPP-5 goal.

Table 2
1998 PacifiCorp DSM Goals and Achievements by Sector (Mwa)*

	1998 Goals	1998 Achievement	
SECTOR / MARKET	**RAMPP-5 (MWa)**	**Mwa**	**Percent of RAMPP – 5 Target**
Existing Residential		0.09	
Appliances		0.03	
New Residential		0.02	
Residential	**0.11**	**0.14**	**128 %**
Commercial Energy FinAnswer		0.52	
Small Commercial Incentive		0.42	
Commercial	**1.20**	**0.94**	**78%**
Industrial	**0.48**	**0.32**	**67%**
Total (Planned @9 aMW)	**1.79**	**1.40**	**78%**
Total (Planned @ 13 aMW)	**2.59**	**1.40**	**54%**
Total NEEA		**2.80**	
Total with NEEA		**4.20**	**235%**

* Savings adjusted by line loss factors to generation level.
** Percentages based on KWh (see Table 3) for consistency and increased accuracy.

The Company has included the savings associated with NEEA programs in the 1998 Company totals. The NEEA savings were calculated as an estimated annual average of 10 year expected savings. Annual NEEA savings will change as NEEA programs are evaluated and new programs are added and others will be deleted. (Description of NEEA programs and Company involvement are included on page 15 of this report.).

Residential

The residential sector reached 128% of goal. The Company continues to promote weatherization measures through the 6.5% Low interest loan and rebate program as well as no cost services to low income households through the Low Income weatherization program. Also in 1998, PacifiCorp continued to acquire savings through efficiencies realized through the Hassle Free Water Heater Guarantee appliance program. 1998 also saw the final year for the Super Good Cents program after nearly a decade of program implementation. This has been a successful residential market transformation program, providing efficiencies above Oregon building code in the new construction market.

Commercial & Industrial Sectors

The commercial sector reached 78% of goal and the industrial sector reached 67% of the Company goal of 1.79 MWa. The Company reached 75% of the goal for commercial and industrial programs as a combined sector. The Company offers the Energy FinAnswer program to commercial and industrial customers and provides the Small Commercial Retrofit program to commercial customers whose facilities total less than 20,000 square feet. The Energy FinAnswer program consists of engineering services and financing offered to the customer by the Company.

The commercial sector fell short of the goal in part due to the fact that the Oregon Commercial code has improved and is very high. Thus it has become increasingly difficult to exceed code in the commercial new construction market.

The industrial sector fell short in reaching 67% of the sector goal. Our results are in part related to economic conditions. Several of our industrial customers are in the very competitive commodities business and have been adversely effected by the downturn in the Asian economy. This has promoted these customers to put any energy efficiency measures and plant upgrades on hold for the time being.

Table 3 below shows program-by-program targets and achievements in KWh as well as levelized Total Resource Cost (TRC) and Cost Effectiveness Levels (CEL).

Table 3
1998 PacifiCorp DSM Goals and Achievements (KWh)
(At generation level)

Program	1998 Target (KWh) @ generation	Achieved Savings (KWh) @ generation	Percent of Target	Levelized TRC (mills/ kWh)	CEL (mills/ KWh)
Non Low Income Weatherization					
6.5% Loan		41,814		173.0	25.13
Rebate		603,586		98.8	25.13
Low Income Weatherization		182,487		224.6	25.13
Total Weatherization		827,887			
Appliances					
Hassle Free Water Heaters		262,608		21.00	25.55
Total Appliances		262,608			
Total Existing Residential					
Super Good Cents		141,551		82.0	27.07
Total New Residential		141,551			
Total Residential	**963,600**	**1,232,046**	**128%**		
Commercial Energy FinAnswer		4,530,185		29.00	28.06
Small Commercial Incentive		3,705,937		21.00	27.70
Total Commercial	**10,512,000**	**8,236,122**	**78%**		
Industrial Energy FinAnswer		2,804,016		17.00	25.84
Total Industrial	**4,204,800**	**2,804,016**	**67%**		
Total Company 1998 DSM	**15,680,400**	**12,272,185**	**78%**		
NEEA		24,552,880			
Total Company 1998 DSM	**15,680,400**	**36,825,065**	**235%**		

RESIDENTIAL PROGRAMS

Overall, PacifiCorp achieved **1,232,046 KWh (0.14 MWa)**, or **128%** of its total residential goal of **963,600 KWh (0.11 MWa)**. The Company's residential programs in 1998 included Low Interest Loan and Rebate Weatherization, Low Income Weatherization, Long Term Super Good Cents, Hassle Free and Market Transformation Appliance offerings.

Residential Weatherization (Schedules 7 and 9)

The residential weatherization effort for the Company included the low-interest loan and rebate weatherization (Schedule 9) and low-income weatherization (Schedule 7) programs. The total savings achieved were 827,887 KWh. Savings for the loan and rebate programs were adjusted per the final evaluation report dated December 15, 1997. Low-income weatherization savings were adjusted per the September 24, 1996 final evaluation report.

Required under Oregon law, the 6.5% interest loan or 25% rebate weatherization program offers customers flexibility in the weatherization measures they choose. Customers have the choice of financing cost-effective measures through a 6.5% loan or receiving a cash rebate for 25% of the cost-effective amount of energy efficient measures, up to a maximum amount of $1,250. This program is available to single family, multi-family, and mobile home dwellings with permanently installed operable electric space heat.

During 1998, 656 homes were weatherized by PacifiCorp in Oregon under the weatherization rebate and loan tariff, Schedule 9. Seventeen units were weatherized under the loan program and 428 units under the rebate program. In the low-income weatherization program, Community Action Programs (CAPs) weatherized 211 Oregon low-income homes in 1998 in partnership with PacifiCorp under Schedule 7.

Table 4 below shows the 1998 program performance for Number of Units, Savings (KWh), Utility Cost (mills/KWh) and TRC (mills/KWh) for each of the residential weatherization programs.

Table 4
1998 Weatherization Program Performance
Total Savings and Cost-Effectiveness
(At generation Level)

Program	Number Of Units	Savings (KWh)	Utility Cost (Mills/kWh)	TRC (Mills/kWh)
6.5 % Loan	17	41,814	75.0	173.0
Rebate WX	428	603,586	33.0	99.0
Low Income	211	182,487	89.0	225.0
Total	656	827,887		

As in 1997, PacifiCorp considers the regional public purpose discussions in conjunction with direct access legislation the appropriate arena to discuss future options for public purpose DSR, including general weatherization, energy efficiency offerings and low-income weatherization. The Company will continue to work with the OPUC and other interested parties in this and other forums to ensure that these programs will be transitioned to a public-purpose funded entity in the region. In the interim, the Company will continue to provide services under the statutory loan and rebate programs and low-income weatherization customers.

Residential Appliance Programs

PacifiCorp acquired 262,608 KWh at the generation level from the Hassle Free program.

Hassle Free Program (Schedule 11)

The Hassle Free Guarantee Program is a water heater repair and/or replacement program developed specifically for residential homeowners who have electric water heat. The program offers three separate options to meet customers' water heating needs. The three options include Premium Hassle Free, Landlord Hassle Free and Basic Hassle Free.

For all three options, the customer initiates coverage by calling the Company's Energy Services Hotline. All electric replacement tanks provided through the program must meet minimum EF ratings: .93 for 52 gallon, .91 for 59-66 gallon capacity, and highest efficiency rating consistent with installations for all other tanks. When the installation occurs, the replacement of the water heater is accompanied with up to six feet of pipe wrap on the cold and hot water pipes, low flow showerhead installations and aerators.

The Company provided replacement tanks to 1,254 customers in 1998. During these replacements, low-flow showerheads, and pipe wrap were installed. In some cases, bottom boards were also installed. The resulting savings from 1998 efforts was 262,608 KWh at the generation level.

Table 5 below shows the 1998 program performance for Savings (KWh), Utility Cost (mills/KWh) and TRC (mills/KWh).

Table 5
1998 Hassle Free Program Performance
Total Savings and Cost-Effectiveness
(At generation Level)
(includes water heater wrap)

Units	Savings (KWh)	Utility Cost (Mills/kWh)	TRC (Mills/kWh)
1,254	262,608	26.0	21.0

Table 6 below shows total measures installed and related savings at the customer site level. Included in the Hassle Free savings and costs are those numbers associated with the Water Heater Wrap Program.

Table 6 1998 Hassle Free Program Measure Savings			
Measure Description	**Savings Per Unit (KWh)**	**Number Units**	**Total Savings (KWh)**
Water Heater (52 gallon – EF .93)	160	1,235	197,600
Water Heater (66 gallon – EF .91)	180	19	3,420
Water Heater Wraps*	200	0	0
Low Flow Showerhead	600	36	21,600
Pipe Wrap	90	109	9,810
Bottom Boards	30	3	90
Total @ Customer Site Level			232,520
Total @ Generation Level			262,608

*Water Heater Program

The Company anticipates no modifications to the Hassle Free program at this time.

Residential New Construction

In 1998, the Company achieved energy savings from Long Term Super Good Cents in the residential new construction market. A total of 141,551 KWh of savings was achieved.

Super Good Cents Program (Schedule 8)

The Super Good Cents Program was initiated to maximize the efficient utilization of electricity requirements of new residential dwellings through the installation of permanent energy savings materials and energy efficient technologies. The Super Good Cents program was canceled in February 1998 after successful implementation of nearly ten years. Over the period of time the program was in effect, the Company made numerous changes to the program to update and promote higher efficient building materials, which eventually became standard building practice. This new construction program promoted efficiencies above and beyond Oregon building code and over the course of the program worked as a model for a successful market transformation program.

In early February 1995, the Super Good Cents program was modified so that only supplemental measures received incentives although shell measures continued to be required. During 1998, 105 homes in Oregon qualified for the Long-Term Super Good Cents program. In addition, at least one of the supplemental measures was installed for each unit certified under the new program. This represented a total of 141,551KWh at the generation level in 1998. Savings were adjusted per the March 19, 1999 Super Good Cents evaluation report.

The OPUC approved the Company request to cancel the Super Good Cents program in February 1998. Builder agreements in place prior to that date with homes completed and certified by 12/31/98 qualified for the incentive and are included for 1998 program savings. This program is no longer available in the state of Oregon.

Table 7 below shows the 1998 performance at the generation level. Shell measure savings are based on the May 26, 1995 evaluation. The program continues to be non-cost effective at a TRC of 82.0 mills per kWh compared to a CEL of 27.07 mills per kWh.

Table 7
1998 Super Good Cents Program Performance
Total Savings and Cost-Effectiveness
(At generation level)

Units	Savings (KWh)	Utility Cost (Mills/kWh)	TRC (Mills/kWh)
105	141,551	70.0	82.0

COMMERCIAL AND INDUSTRIAL

(Schedule 125) Energy FinAnswer
(Schedule 115) Small Commercial Retrofit

Overall, the Company achieved **8,236,122 KWh (.94 MWa)** or **78%** of the goal of **10,512,000 KWh (1.20 MWa)** of savings in the commercial sectors and **2,804,016 KWh (.32 Mwa)**, or **67%** of the industrial goal achieved for Company programs.

The Company operates Energy FinAnswer (Schedule 125) as one program with the Commercial and Industrial sectors combined to meet one goal. Company employees strive to bring in a variety of projects both in the commercial and industrial sectors as well as small, medium and large projects with geographic diversity. Specific commercial or industrial accomplishments in a given year vary due to the ebb and flow of projects and construction and maintenance activities of our customers. Work with customers is ongoing often with long lead times for many of the projects.

The Energy FinAnswer program was designed to improve the energy efficiency of new and existing commercial buildings and industrial facilities, with the exception of existing commercial buildings under 20,000 square feet. The Energy FinAnswer Program includes what used to be called the Commercial Custom, Prescriptive, and Commercial Retrofit programs and also includes the Industrial sector. (Schedule 125 does not cover Small Commercial Retrofit, which is provided under Schedule 115 and discussed separately below).

Energy FinAnswer is an energy service program, which offers financing, engineering analysis, design, and information regarding energy efficiency improvements. The customer has the option of Company offered financing for energy efficient measures which are classified as path A projects or path B projects where customers finance their own projects. Upon completion of measure installation, the Company performs an inspection to verify installations of energy efficient improvements.

In 1998, PacifiCorp began providing program information via the Internet to increase customer participation as well as program cost effectiveness. The web site address is www.pacificorp.com/business/finanswr and has been an added tool to enhance and promote communication with our customers. While no major program change occurred in 1998, an internal program management change was implemented in an effort to target and screen projects more thoroughly on the front end and focus company energies into projects that are more likely to move forward and result in a completed project. This translates into working more closely with customers to access the customer decision making process and financial criteria for a successful project. Any further adjustments in the Energy FinAnswer program will be directed toward maintaining or increasing cost effectiveness and meeting customer needs in a changing marketplace.

Commercial Energy FinAnswer Program (Schedule 125)

The total savings achieved from the Commercial Energy FinAnswer Program were 4,530,122 KWh. The savings reported here are adjusted, based on evaluation findings for the Custom, Prescriptive and Retrofit programs and savings were adjusted by evaluation results for Oregon from evaluations finalized in March 1999. Although evaluation reports are still being reported separately by program, the Company finished merging the programs in 1997 and will only be reporting the totals shown in Table 8.

For the Commercial sector for the new construction market on a per project basis, the resulting savings are very small due to the high level of Oregon commercial codes and the inability to exceed code cost effectively.

A combined commercial Energy FinAnswer cost-benefit analysis was run. The results are 11.0 mills/kWh utility cost and 29.0 mills/KWh TRC compared to the 28.06 mills/kWh CEL.

Table 8 below shows the 1998 program performance for Number of Units, Penetration Rate, Savings (KWh), Utility Cost (mills/KWh) and TRC (mills/KWh).

Table 8
1998 Commercial Energy FinAnswer Program Performance
Total Savings, Penetration and Cost-Effectiveness
(At generation level)

Year Program	Number Of Units	Savings (KWh)	Utility Cost(Mills/ KWh)	TRC (Mills/KWh)
Commercial EFA	36	4,530,185	11.0	29.0

Industrial

Achievements in the industrial sector were 2,804,016 KWh or .32 MWa, or 67% of the industrial goal achieved.

This represents 7 projects in the Industrial sector. Energy efficiency efforts in this industrial sector have focused on lighting, high efficiency motors, air compressor systems, refrigeration, and VFD's system upgrades.

The energy efficient measure mix for 1998 is different than in 1997. The mix for this year includes mainly lighting upgrades and motor efficiencies compared to more involved process plant improvements that were done in 1997. This year the measure mix project costs are much less and also easier to quantify thus the TRC looks much improved.

Table 9 below shows the 1998 program performance for Number of Units, Penetration Rate, Savings (KWh), Utility Cost (mills/KWh) and TRC (mills/KWh).

Table 9
1998 Industrial Energy FinAnswer Program Performance
Total Savings, Penetration and Cost-Effectiveness
(At generation level)

Year Program	Number of Units	Savings (KWh)	Utility Cost (Mills/kWh)	TRC (Mills/kWh)
Industrial EFA	7	2,804,016	8.0	17.0

Small Commercial Incentive Program (Schedule 115)
The Small Commercial Program was designed to improve the energy efficiency of existing commercial buildings and industrial facilities under 20,000 square feet. The Company provides cash incentives to participating owners or tenants who install recommended energy efficient measures in their facilities. The incentives are provided upon verification of installation.

The total savings achieved from the Small Commercial Incentive program were 3,705,937 KWh from 154 facilities or buildings. The savings estimates derived from the engineering model were used as the savings for this program. This program looks cost-effective, with a TRC of 21.0 mills compared to a CEL of 27.7 mills/kWh.

Table 10 below shows the 1998 program performance for Number of Units, Savings (KWh), Utility Cost (mills/KWh) and TRC (mills/KWh).

Table 10
1998 Small Commercial Incentive Program Performance
Total Savings and Cost-Effectiveness
(At generation level)

Units	Savings (KWh)	Utility Cost (Mills/KWh)	TRC (Mills/KWh)
154	3,705,937	6.0	21.0

In 1998, PacifiCorp provided program information via the Internet to increase customer participation, communication and cost effectiveness. There is an incentive calculation in the internet program that allows the customer to calculate what the incentive would be using a variety of measures. The Company is currently reviewing the incentive rebate levels for the Small Commercial program and is contemplating a revision to the rebate levels to better reflect the current market conditions.

Market Transformation / Regional Activities

The Company has been involved with market transformation efforts since the inception of Super Good Cents in 1988. Since then, PacifiCorp has actively participated in the development of commercial and residential building codes, the Manufactured Acquisition Program (MAP), and appliance programs including the Super Efficient Refrigerator Program (SERP), high-efficiency showerheads, water-heaters, and heat pumps.

In 1996, PacifiCorp helped in the development of the Northwest Energy Efficiency Alliance (NEEA). This group was officially formed in October, 1996.

From published NEEA information, "The Northwest Energy Efficiency Alliance is a non-profit consortium of utilities, governments, public-interest groups and the private sector dedicated to transforming markets for energy-efficient products and services.

It seeks to bring about significant and lasting changes in markets for energy-efficient technologies and practices, to improve the region's efficient use of energy and reduce costs to consumers and the electric system. The Alliance also hopes to leverage and provide for non-energy benefits.

Collaboration both inside and outside the region is a vital element of the Alliance, whose members look to market transformation ventures as a means to save considerable energy at potentially low long-term costs. Eventually, the thinking goes, transformed markets will no longer need financial incentives. "

The Alliance's formation reflects widespread support and previous successes for market transformation in Washington, Oregon, Idaho and Montana. Utilities in the four-state region have committed to providing up to $65.5 million for market transformation endeavors from 1997 through 1999. This was budgeted at $13.1 million for 1997 and $27.1 million for each of 1998 and 1999. PacifiCorp's share at 11.3% was $1.5 million for 1997 and $3 million for each of 1998 and 1999.

It is currently estimated that the current NEEA programs have a 10 year estimated annual savings of 35 MWa. PacifiCorp's allocated portion at 11.3% is 4 MWa per year.

Some of NEEA's current approved projects for: 1998 were:

Infrastructure Support - providing information, education and technical assistant on state of the art energy efficiencies, local government liaison to energy efficient products, and support for National Standards
Commercial - architecture education, building use energy models, building operator certification and building commissioning services
Residential - compact fluorescent fixtures , high-efficiency window products and horizontal-axis washers
Industrial, industrial motor testing and refrigerated warehouse design improvements

Refer to Appendix #1 for more detail on NEEA structure, funding and current approved projects.

Appendix 1

(The following write-up has been excerpted from published NEEA information)

Structure

The Northwest Energy Efficiency Alliance is governed by an 18-member board of directors responsible for among other duties selecting and approving funding for market transformation projects, reviewing and evaluating results, and providing guidance to staff. A six-member executive committee oversees the Alliance's administration, hires the executive director and conducts other board business between meetings as authorized. Executive Director Margaret Gardner is charged with carrying out the board's directions and managing the Alliance's day-to-day activities. She previously served as the Alliance's deputy director, and before that as a conservation analyst with the Northwest Power Planning Council. Several other staff people also conduct Alliance business. In addition, a number of non-profit, public- and private-sector contractors are working on specific Alliance market transformation initiatives.

Funding

The Northwest Energy Efficiency Alliance's maximum committed budget amounts to $13.1 million for 1997 and $26.2 million in both 1998 and 1999, for a three-year total of $65.5 million. The amount actually spent may be less, depending on the decisions of the Alliance board of directors. The years in which the money is spent also may vary.

Funding for the Alliance comes from seven sources: Bonneville Power Administration (on behalf of its public-power and direct-service customers) and the six major investor-owned utilities serving the region: Idaho Power, Montana Power, PacifiCorp, Portland General Electric, Puget Sound Energy (formerly Puget Sound Power & Light, until its merger with Washington Energy) and Washington Water Power.

Bonneville's share is 57.3 percent, the IOUs' 42.7 percent (see the chart below for a detailed breakdown). The shares were determined by 1994 regional power sales, adjusted for IOU net revenues paid to BPA.

IOU funding for the Alliance is conditioned on regulatory approval for recovery of Alliance costs through rates. Should such cost-recovery be denied by regulators, funding can be withheld. In addition, IOU participation in the Alliance is contingent on market transformation activities counting toward demand-side resource acquisition goals.

Beyond 1999, Alliance funding is uncertain. It will depend on several factors, notably electric industry restructuring and the Alliance's performance.

Utility	1997 Alliance Funding (millions of dollars)	1998 and 1999 Annual Funding (millions of dollars)	Total Funding 1997-1999 (millions of dollars)	Funding share (approx. percent)
Idaho Power	0.85	1.70	4.25	6.5
Montana Power	0.18	0.37	0.92	1.4
PacifiCorp	1.49	2.97	7.43	11.3
Portland General Electric	1.20	2.40	6.00	9.2
Puget Sound Energy (formerly Puget Sound Power & Light)	1.36	2.71	6.78	10.3
Washington Water Power	0.52	1.04	2.60	4.0
Investor-owned Utility Total	5.60	11.19	27.98	42.7
BPA	7.50	15.00	37.50	57.3
Regional Total	13.10	26.19	65.48	100. 0

The Northwest Energy Efficiency Alliance will successfully demonstrate that cost-effective electricity efficiency can be achieved through market transformation, and that the Alliance is an organization capable of providing market transformation activities in the future. The reason to promote electricity efficiency is to decrease the long-term societal costs and environmental impacts of the electricity system.

Current Approved Projects

Through 1998, the Alliance board has approved funding for the following market transformation projects:

Architecture + Energy: Building Excellence in the Northwest

Through an awards program as well as regional workshops and other educational efforts, this project helps inform the people who design commercial buildings about the value and benefits of energy-efficient architecture.

Bac-Gen BioWise Wastewater Treatment Initiative

In this unique project, the Alliance is funding the development and demonstration of a micro-nutrient assisted digestion technology that will greatly enhance a wastewater treatment facility's ability to process effluent. The project targets municipal, industrial and agricultural wastewater facilities. As part of this project, a business plan will be developed and implemented along with dissemination of demonstration site results.

Commissioning Public Buildings in the Pacific Northwest

The integration of commissioning into Northwest state and local government buildings is the focus of this venture, which includes training and education initiatives, case studies, enhanced development of commissioning services, and communications to public-facility officials on the many benefits of commissioning building systems so they operate as designed. The purpose, within each state as well as regionally, is to curry government support for commissioning through policies as well as practice.

The Alliance financially supports publication of a monthly on-line newsletter covering energy efficiency and renewable energy around the Pacific Northwest. The Alliance is developing a long-range strategy for supporting energy codes around the region. It is also funding interim energy code work by state energy agencies in the four Northwest states, until the long-term strategy is developed. The long-term goals focus on stable funding for supporting codes, improved compliance with existing statewide energy standards, and a means for new energy efficiency measures to be incorporated into codes.

Energy Ideas Clearinghouse

The Energy Ideas Clearinghouse provides information, education, resources and technical assistance on energy efficiency, through toll-free hotlines, technical engineering assistance, library research, a bulletin board system, a Web site and other services and materials relating to energy-efficient practices, technologies and products.

Energy Star Residential Fixtures (Compact Fluorescent Fixtures)

This venture offers performance awards to manufacturers and/or wholesale distributors of energy-efficient lighting fixtures, as a means to address the key market obstacles of limited availability, high retail costs and spotty awareness. The program links selected retailers and wholesalers with manufacturers of energy-efficient fixtures; it also includes a consumer marketing and advertising campaign to spread the word about the benefits of this technology.

Energy Star Resource-Efficient Clothes Washers

This project promotes resource-efficient clothes washers – and their substantial energy, water and detergent savings. It is aimed at increasing the market share of resource-efficient washers through aggressive marketing and support for higher federal efficiency standards for clothes washers.

Energy Star High Efficiency Residential Windows
This program intends to boost consumer demand and market share for windows, doors, skylights and other fenestration products that exceed applicable energy code standards. Activities include various promotional initiatives (such as advertising and product branding), sales training for manufacturers and technical assistance for builders.

In-Service Industrial Motors
This project will test and demonstrate specific ways to assess the efficiency of existing motors in Northwest industries, and document how motor testing can benefit industrial plants. The long-term goal of this project is to accelerate the replacement of inefficient motors.

Lighting Design Lab
The Seattle-based Lighting Design Lab is continuing its mission of promoting energy-efficient lighting around the Pacific Northwest. Under this Alliance venture, the Lab is targeting lighting specifiers for the retail, office, daylighting and residential sectors; working with colleges and trade schools to train students; partnering with trade allies, professional organizations, Alliance projects and Northwest utilities; expanding its regional approach through increased marketing, advertising and electronic media; and serving as the Alliance representative to the New York-based Lighting Research Center.

Lighting Research Center
The Alliance has agreed to join the Lighting Research Center's Partners Program, which gives the Alliance access to the New York-based center's expertise, information services, technical resources and research/development efforts, and enables networking with other LRC partners such as utilities, governments and corporations. The Alliance has also signed up for LRC's Product Information Program, which provides extensive reports on the performance of specific lighting products and designs.

LightWise (Compact Fluorescent Lighting)
Targeting the residential lighting market, LightWise strives to overcome market barriers to energy-efficient compact fluorescents by lowering retail costs, increasing availability and expanding consumer awareness and acceptance. The program offers a $5-per-bulb rebate to participating manufacturers of high-quality, energy-saving compact fluorescents, which typically use one-fourth the energy of incandescent bulbs and last 10 times as long.

Local Government Associations The Alliance has allied with local government organizations in the four Northwest states to promote market transformation and specific ventures among towns, cities and counties. Current tasks include recruiting water utilities for the WashWise program, marketing the Building Operator Certification program, communicating to local governments on market transformation and energy efficiency issues, and providing energy code support.

Scientific Irrigation Scheduling

This venture provides information and assistance to expand the regional practice of scientific irrigation scheduling, which enables irrigators to supply the right amount of moisture to their crops at the right time. SIS saves considerable energy while cutting irrigation costs, conserving water, reducing the use of agricultural chemicals and potentially improving crop yields and quality.

Silicon Crystal Growing Facilities

This project seeks improved efficiencies in energy-intensive crystal growing furnaces where silicon ingots are produced for photovoltaic and semiconductor applications. The initial focus is on developing and implementing furnace efficiencies at Siemens Solar Industries facilities where silicon ingots are produced for the photovoltaic industry; the eventual goal is to transfer the new technology to the much larger semiconductor industry.

Super Good Cents Manufactured Housing/Manufactured Housing Advertising

Developing the market for manufactured homes built to Super Good Cents energy-efficient standards, and maintaining a regional support infrastructure, are the objectives of this venture that follows the Manufactured Housing Acquisition Program (MAP). This program includes regional television advertising, retailer sales training and marketing support, promotion of financing for manufactured-home buyers, and education to promote proper site preparation and installation of these energy-efficient residences.

Microelectronics Industry Efficiency Initiative

This venture aims to identify and pursue efficiency opportunities in the booming and energy-intensive Northwest microelectronics industry. Specifically, the Alliance will seek out an integrated design process in which to enhance energy efficiency for a semiconductor manufacturing facility, participate in important industry forums and assess potential efficiencies in the polysilicon manufacturing process.

National Standards

This project funds participation by Oregon Office of Energy staff in three national forums that are instrumental in setting national energy efficiency standards: the U.S. Department of Energy committee on appliance efficiency standards, which is revising clothes washer and water-heater efficiency standards; the National Fenestration Rating Council technical steering committee; and the ASHRAE/IESNA 90.1 commercial building codes lighting subcommittee, which is drafting new lighting guidelines that states will be required to adopt.

Northwest Energy Education Institute

Energy efficiency training and education are conducted through the Northwest Energy Education Institute, based at Lane Community College in Eugene, OR, but serving the entire region. The institute provides customized training for energy professionals as well as specific training in support of Alliance market transformation ventures. It also will offer an energy efficiency degree program available regionally, and will promote energy efficiency curricula in Northwest community colleges.

Northwest Lighting On-Line

Targeting the commercial lighting market, this project offers Internet access to lighting design resources, primarily for lighting specifiers and contractors. It includes development of a Northwest lighting Web site, along with energy-efficient lighting design features and product search tools on existing Web sites.

Public Housing Efficiency

This venture seeks to demonstrate to public-housing authorities the benefits of life-cycle cost analysis and resource efficiency management services, and to put those into widespread practice to improve the efficiency of public-housing heating systems and appliances. Also planned is work with state and federal agencies to develop regional energy efficiency guidelines for public-housing projects.

Overview of local system planning discussion

- Components of local T&D capital plan
  - Growth driven transmission reliability projects
  - Growth driven substation capacity projects
  - Growth driven distribution feeder projects
  - Asset management
    - » Repair/Replace
    - » Modernize/Upgrade
    - » Regulatory Mandated

Local Transmission System Planning

<u>Ability of local transmission system to support customer load growth</u>

LOCAL TRANSMISSION SYSTEM PLANNING STUDIES

The purpose of the local transmission system planning study is to provide a multi-year plan for the development of the transmission and substation systems in company service areas. PacifiCorp's operability and reliability criteria is used as a guide.

STUDY AREA DEFINITIONS

Central Oregon
Clatsop
Dalreed/Arlington/Sherman
Enterprise
Hood River
~~Montana~~
Pendleton/Hermiston
Portland
Wallula
Crescent City
Junction City/Cottage Grove
Honeyville/Malad
Lincoln City
Park City/Midway
Southern Oregon 500/230 kV
Tooele

Eastern Utah
Nebo
Pavant
Sigurd
Southeast Utah
Southwest Utah
Utah Valley
Vernal
Coos Bay
Grants Pass
East Salt Lake Valley
Lakeview/Alturas
North Salt Lake
Roseburg
South Ogden
Yreka/Mt. Shasta

Bear Lake
Big Horn
Goshen
Grace
Powder River
Southern Wyoming
Wyoming West
Walla Walla
Yakima Valley
Cache Valley
Klamath Falls
North Ogden
Medford
Salt Lake City/Millcreek
Willamette Valley
West Salt Lake Valley

STUDY CONTENT

Signature Sheet
Executive Summary
General System Description
Transmission Map
Line Ratings
System Problems/ Future Requirements
System Loss Savings
Recommended Construction Summary

Projected Loads
Equipment Ratings
Fault Interrupting Ratings
Airbreak Switch Capabilities
Capacitor Banks
Outage Summary
Selected Power Flow Base Case Plots

STUDY DISTRIBUTION

Resource & Transmission Planning Mgr.
System Planning Supervisor
System Planner - Portland
Retail Vice President
Technical Operations Asst. Vice President
Technical Operations Division Manager
Technical Operations Manager
Principal Dispatcher - SOCC or SPCC
System Planner SPCC
Sub-Dispatch Office
Operations Assistant Vice President
Area Operations Manager
Operations Manager
General Business Manager
Strategic Account Manager
Operations Engr. Asst. Vice President
Region Engineer

Area Engineer
Customer Technical Product Engr. (DSM)
Engineering Senior Vice President
Trans. & Dist. Engineering Director
Engineering Service Manager
Substation & Protection/Control Engr. Mgr.
Lead Substation Engineer
Lead Relay Engineer
Transmission Engineering Manager
Lead Transmission Engineer
Distribution & Meter Engineering Manager
Communications Engineering Manager
Area Planning Engineer
Area Planning Engineering Manager
Area Planning Engineering Supervisor
Area Planning Principal Engineer

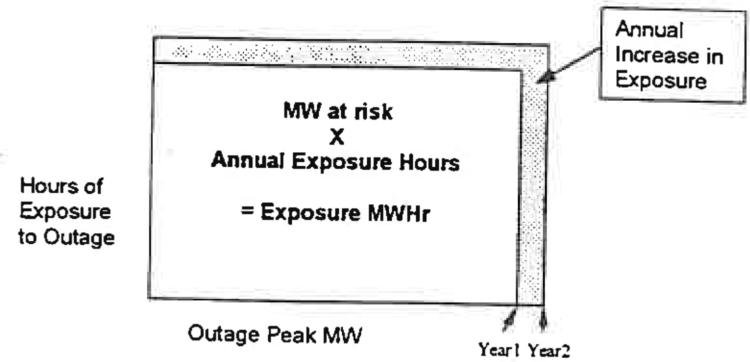
Ability of local transmission system to support customer load growth - Study Phase

- Perform studies to identify predicted violations of WSCC or company reliability criteria:
  - Projected overloaded transmission system transformers or lines during normal system operations (N-0 violations)
  - Projected overloads or low voltages with one line or transformer out of service (N-1 violations)

Ability of local transmission system to support customer load growth - Prioritization Phase

- For each violation of reliability criteria, customer outage exposure determined
  - Major Outage exposure factors are:
    - ✓Peak MW load at risk for shedding
    - ✓Annual hours of shedding risk
  - Minor factors used:
    - ✓Predicted outage likelihood
    - ✓Expected outage duration

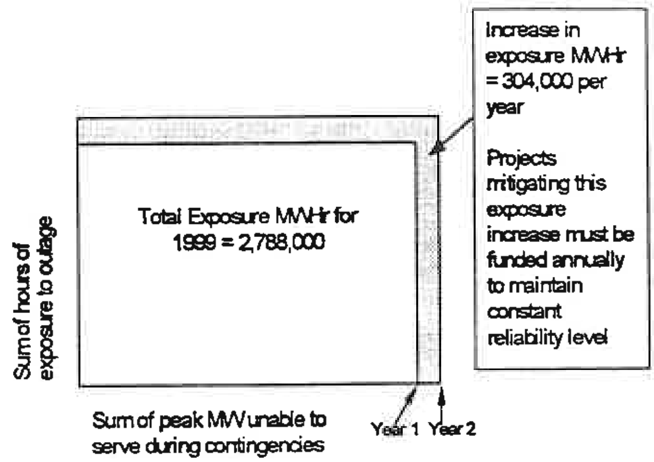
Measuring Single Exposures in terms of "Exposure MWHr"



Relative Prioritization of Transmission Projects Using "Exposure MWHr"

- Once costs, value of loss savings, and MWHr of outage exposure are known for projects mitigating N-1 exposures, relative ranking of projects can be performed
- Cost/benefit = (project cost - NPV loss savings)/MWHr exposure

Single outage exposures can be summed to indicate total company exposure



Projected funding required to prevent local area transmission risks from increasing:

- Average annual requirement = $ 18,000,000 to keep up with load growth

Substation Capacity Planning

- Growth studies performed to identify substations needing load relief (load transfers, new transformers, or larger transformers).
- Planned MVA of new distribution substation capacity is compared with projected load growth rates, modified by transformer utilization ratio and power factor.

Substation Capacity Planning

- At present 9200 MW total non-coincidental company load and 2% peak growth rate, 184 MW of new load is expected annually.
- At 80% average transformer utilization factor and 95% power factor, this results in 242 MVA of new transformer capacity per year.

Substation Capacity Planning

- Current long-range capital plan specifies
  - 170 MVA installed in 1998
  - 324 MVA being installed in 1999
  - 223 MVA to be installed in 2000
  - 255 MVA to be installed in 2001
- Four-year average is 243 MVA, compared to projected requirement of 242 MVA

Distribution Substation Capacity from Ten Year Plan

Distribution Substation Capacity Plan

AREA	1998 NON-CONCIDENTAL BASE LOAD FOR AREA	PERCENT GROWTH RATE, excluding negative growth areas	ANNUAL MW GROWTH	ANNUAL MVA REQUIRED	Five Years, 1999-2003 TOTAL	Five Years, 1999-2003 TOTAL PER YEAR	MVA I 1999	2000	2001	2002	2003
P.R.O. South	2212	1.9%	42.0	55.3	153.0	30.6	9.4	5.0	0.0	75.0	63.6
P.R.O. North	2330	2.0%	46.6	61.3	101.6	20.3	5.0	5.0	10.6	25.0	56.0
Idaho/Wyoming	1881	1.0%	18.8	24.8	156.2	31.2	34.4	27.0	3.4	72.4	19.0
Salt Lake Valley					517.8	103.6	172.6	148.0	71.4	80.4	45.4
Ogden					382.4	76.5	56.2	3.5	59.9	198.7	64.2
Northern Utah Subtotal					900.1	180.0	228.8	151.5	131.3	279.0	109.6
Southern Utah					245.6	49.1	46.2	34.1	109.5	32.0	23.8
State of Utah Total	2778	4.5%	125.0	164.5	1145.7	229.1	275.0	185.6	240.8	311.0	133.4
Company Total	9201	2.5%	232.4	305.9	1556.5	311.3	323.8	222.6	254.8	463.4	272.0

This table updated September, 1999

Distribution Substation Capacity Ten Year Plan

AREA	1998 NON-COINCIDENTAL BASE LOAD FOR AREA	PERCENT GROWTH RATE, excluding negative growth areas	ANNUAL MW GROWTH	ANNUAL MVA REQUIRED	Five Years, 1999-2003 TOTAL	Five Years, 1999-2003 TOTAL PER YEAR	MVA Installed 1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
P.R.O. South	2212	1.9%	42.0	55.3	153.0	30.6	9.4	5.0	0.0	75.0	63.6	23.1	48.1	66.0	48.9	0.0
P.R.O. North	2330	2.0%	46.6	61.3	101.6	20.3	5.0	5.0	10.6	25.0	56.0	51.6	85.7	0.0	75.0	25.0
Idaho/Wyoming	1881	1.0%	18.8	24.8	156.2	31.2	34.4	27.0	3.4	72.4	19.0	15.3	54.4	42.4	36.0	0.0
Salt Lake Valley					517.8	103.6	172.6	148.0	71.4	80.4	45.4	39.0	157.6	145.9	90.0	60.0
Ogden					382.4	76.5	56.2	3.5	59.9	198.7	64.2	31.6	65.2	60.0	93.5	7.6
Northern Utah Subtotal					900.1	180.0	228.8	151.5	131.3	279.0	109.6	70.6	222.8	205.9	183.5	67.6
Southern Utah					245.6	49.1	46.2	34.1	109.5	32.0	23.8	2.5	135.1	24.3	60.0	0.0
State of Utah Total	2778	4.5%	125.0	164.5	1145.7	229.1	275.0	185.6	240.8	311.0	133.4	73.1	357.9	230.2	243.5	67.6
Company Total	9201	2.5%	232.4	305.9	1556.5	311.3	323.8	222.6	254.8	483.4	272.0	163.1	546.1	338.6	403.4	92.6
Cummulative Total							323.8	546.4	801.1	1284.5	1556.5	1719.5	2265.6	2604.2	3007.6	3100.2
Running Average							161.9	182.1	200.3	256.9	259.4	245.6	283.2	289.4	300.8	281.8

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. _____

In the Matter of the Application of PACIFICORP for an Order Approving The Sale of its Interest in (1) the Centralia Steam Electric Generating Plant, (2) the Ratebased Portion of the Centralia Coal Mine, and (3) related facilities; for a Determination of the Amount of and the Proper Ratemaking Treatment of the Gain Associated with the Sale; and for an EWG Determination	)))))))))))	**APPLICATION OF PACIFICORP**

PacifiCorp (or the "Company") files this application pursuant to the provisions of ORS 757.480, ORS 757.125, OAR 860-13-010 and 860-27-025. The provisions of ORS 757.480 require Oregon Public Utility Commission ("Commission") approval of any transaction selling or otherwise disposing of public utility property necessary or useful in the performance of the public utility's duties to the public.

PacifiCorp seeks a Commission order approving the sale of the Company's interests in (a) the Centralia steam generating plant, consisting of two generating units, each with 650 megawatt nameplate rating and other related facilities, and (b) the ratebased portion (47.5%) of the Centralia Coal Mine located in Lewis and Thurston Counties, Washington. The purchaser of the Centralia generating unit interests is TECWA Power, Inc. ("TECWA Power") and the purchaser of the Centralia coal mine is TECWA Fuel, Inc. ("TECWA Fuel"), both Washington corporations, and both wholly-owned indirect subsidiaries of TransAlta

Corporation, a Canadian Business Corporation Act corporation, and guarantor of certain obligations and duties undertaken by TECWA Power and TECWA Fuel.

In addition, PacifiCorp seeks a Commission order adopting the Company's methodology to calculate the gain associated with the sale and the proposed ratemaking treatment of the gain as further described below and in the accompanying prefiled testimony. The gross sales prices are subject to various adjustments. See, § 2.6 of the Centralia Plant Purchase and Sale Agreement (Application Exhibit No. 1) and § 2.5 of the Mine Purchase and Sale Agreement (Application Exhibit No. 2).

Lastly, PacifiCorp seeks a Commission ruling pursuant to 15 U.S.C. § 79z-5a(c) allowing purchaser to operate the Centralia facility as an eligible facility. Specifically, in order to be an "eligible facility" authorizing purchaser to operate the facility as an exempt wholesale generator ("EWG") under federal law, PacifiCorp seeks Commission rulings that operation as an eligible facility (1) will benefit consumers, (2) is in the public interest, and (3) does not violate state law.

Pursuant to the provisions of OAR 860-27-025(3), the Company asks that the filing requirements of OAR 860-27-025(1) and (2) be waived and the Company be authorized to submit its application pursuit to the filing requirements set forth in OAR 860-27-025(3).

1.

A. Name and Address of Petitioner

The full and correct name and business address of Applicant is:

PacifiCorp
Suite 600
825 NE Multnomah
Portland, OR 97232

B. Corporate Information

PacifiCorp, an Oregon corporation, was incorporated on August 11, 1987. PacifiCorp is authorized to transact business in the States of Washington, Oregon, California, Idaho, Utah and Wyoming.

C. Correspondence and Pleadings

All correspondence or communications regarding this application should be addressed to:

For PacifiCorp:

C. Alex Miller
Managing Director of Planning
PacifiCorp
Suite 600
825 NE Multnomah
Portland, OR 97232
Tel (503) 813-7263
Fax (503) 813-7262

With A Copy to:

George M. Galloway
Stoel Rives, LLP
Suite 2600
900 SW Fifth Avenue
Portland, OR 97204
Tel (503) 294-9306
Fax (503) 220-2480

D. Principal Officers

The names, titles and address of PacifiCorp's principal officers are as follows:

Keith R. McKennon
President & Chief Executive Officer
Suite 2000
825 NE Multnomah
Portland, OR 97232

Richard T. O'Brien
Chief Operating Officer
Suite 2000
825 NE Multnomah
Portland, OR 97232

John A. Bohling
Sr. Vice President
Suite 2000
825 NE Multnomah
Portland, OR 97232

William E. Peressini
Vice President and Treasurer
Suite 2000
825 NE Multnomah
Portland, OR 97232

E. Description of Business

PacifiCorp is a public utility providing retail electric service to customers in the six western states of Oregon, Washington, California, Idaho, Utah and Wyoming and wholesale electric service throughout the Western United States.

F. Agreements

A copy of the following transactional documents accompany this application:

(1) Centralia Plant Purchase and Sale Agreement (Application Exhibit No. 1), identifying all assets purchased that are associated with PacifiCorp's 47.5% ownership interest in the Centralia generating plant facility.

(2) Centralia Coal Mine Purchase and Sale Agreement (Application Exhibit No. 2), identifying all assets purchased that are associated with PacifiCorp's 100% ownership interest in the Centralia coal mine facility.

(3) Guarantee Agreement (Application Exhibit No. 3), describing TransAlta Corporation's obligations as a guarantor under specified transactional agreements.

(4) Centralia Auction Sale Agreement and Amendment No. 1 thereto (Application Exhibit No. 4), describing the design of the auction process agreed upon by the owners of the Centralia facilities.

G. Reasons for Sale

The owners of the Centralia facilities decided to sell the assets due principally to the possible need for additional capital expenditures to meet new air emission requirements, and the potential impact of U.S. electric utility industry deregulation trends on the prospect for recovery of utility plant-in-service investments.

H. Purchasers

TransAlta Corporation is a Canadian energy company with $5 billion (Canadian) in assets and is the leading producer of independent power in Canada. TransAlta is the major supplier of electricity in Alberta and also operates in Ontario, New Zealand, Australia and the United States. A copy of TransAlta's 1998 Annual Report to Shareholders which includes TransAlta financial statements accompanies this filing marked as Application Exhibit No. 5. TransAlta is financially able and willing to take over and operate the facilities sold as described in the accompanying transactional documents. A more detailed description of TransAlta is provided in Application Exhibit No. 5.

I. Purchase Price

The gross proceeds from the sale of the generating facility and the mine were allocated between a generating plant price of $452,598,000 and a coal mine price of $101,400,000. The gross purchase prices are subject to certain adjustments which must be incorporated in any calculation of net gain. See § 2.6 of the Plant Purchase and Sale Agreement (Application

Exhibit No. 1) and § 2.5 of the Mine Purchase and Sale Agreement (Application Exhibit No. 2). Each of the owners is entitled to receive a percentage of net proceeds from the sale of the generating facility equal to its ownership percentage and PacifiCorp is entitled to receive the entire net proceeds from the sale of the coal mine facilities. PacifiCorp's share of the gain associated with the sale is estimated to be approximately $83 million on a system-wide basis. The actual dollar value of the net gain on the sale will not be finalized until the close of the transaction. The accompanying prefiled testimony of PacifiCorp's C. Alex Miller contains the Centralia Sellers Agreement (PacifiCorp/7) which describes in detail the establishment of the owners respective rights and obligations associated with the sale of the generating and mine facilities.

2.

A. Prefiled Testimony Accompanying Application

The following PacifiCorp witnesses sponsor prefiled testimony in support of this application:

(1) C. Alex Miller, Managing Director of Planning, PacifiCorp describes the specific approvals sought by PacifiCorp in this filing. In addition, Mr. Miller addresses the auction process and the results of the auction, the ownership interests in the Centralia generating facility, the Plant Purchase and Sale Agreement (Application Exhibit No. 1), PacifiCorp's power replacement strategy and the quantification of the gain associated with the sale.

(2) Dr. Rodger Weaver, Director, Regulatory and Strategy Support, will sponsor analysis that shows the sale of Centralia results in a net benefit to PacifiCorp's customers.

(3) Anne E. Eakin, Vice President Regulation for PacifiCorp, will describe the Company's proposed allocation of the gain associated with the sale and the proposed ratemaking treatment of the gain.

3.

A. Exempt Wholesale Generator

If a facility currently regulated by the state regulatory agency was ratebased at October 24, 1992, and if an operator wishes to make the facility "eligible" to gain EWG status from the Federal Energy Regulatory Commission, the provisions of 15 U.S.C. § 79z-5a(c) require an operator to seek and obtain specific state regulatory commission findings. The specific determinations sought from the Commission are that allowing the facility to be an eligible facility (1) will benefit consumers, (2) is in the public interest, and (3) does not violate State law. PacifiCorp specifically asks for expedited processing of the EWG determination. Expedited processing is important from a timing standpoint. TransAlta cannot commence processing its application with the FERC until the Commission has made the three determinations required by the federal statute. PacifiCorp respectfully asks that the three determinations be made allowing Centralia to be considered an eligible facility at the completion of PacifiCorp's sale to TransAlta. As completion of the sale cannot take place without the relevant state regulatory approvals, this assures that making these determinations will not prejudge the merits of the proposed sale under Oregon statutory standards.

4.

PacifiCorp seeks a Commission order:

(a) approving the sale of the Company's interests in the Centralia steam generating plant and the ratebased portion of the Centralia Coal Mine;

(b) adopting the Company's proposed methodology to calculate the gain associated with the sale and the proposed ratemaking treatment of the gain;

(c) making the three determinations required by 15 U.S.C. § 79z-5a(c) allowing the Centralia generating plant to be considered an eligible facility at the completion of PacifiCorp's sale to TransAlta; and

(d) for such other relief as the Commission deems necessary and proper.

Dated: August 6, 1999.

Respectfully submitted,

PACIFICORP

By James C. Paine

George M. Galloway
James C. Paine
Stoel Rives, LLP
Suite 2600
900 SW Fifth Avenue
Portland, OR 97204-1268
Tel (503) 294-9306 or 294-9246
Fax (503) 220-2480
Of Attorneys for PacifiCorp

Transmission Changes since RAMPP 5

September 10, 1999

Kurt Granat

Continued FERC 888 & 889 Implementation

- Transmission Function separated from
  – Marketing Function
- Limits on Transmission Function personnel sharing information
- Treat All Customers Equal
- Service level to PacifiCorp sets service level for all customers

Regional Transmission Consolidation

IndeGO

- Was seeking comments on proposed
  – FERC Filing
- Of the 21 participants, 11 formally withdrew by March 1998 (not counting BPA)
- IndeGO project effectively ended

Post IndeGO work

- Avista pushed an Independent Grid Scheduler
- Colorado parties continued working on their region
- BPA seems interested in a "Westside" group
- Not clear how active these loose grouping are

Cal ISO and PX

- Operating spring 1998
  –
- High Ancillary Services prices
- Concern that Cal ISO's goals results in overly cautious system operation

Nevada Power / Sierra Pacific Merger

- Approved with the requirement that they join or set up an ISO

Continued FERC interest in ISO's, RTO's or TransCo's

- FERC ISO hearings
- FERC NOPR on Regional Transmission Organizations (RTO's)

System Reliability Efforts since 1996 Outages

WSCC Review of Path Ratings

- Operating Transfer Capabilities established for each season
- More Stringent enforcement of rules
- Large impact on Path C for PacifiCorp
- Major increase in Transmission Planning workload
- Path 15 and Intertie derates

WSCC taking more active role in non-technical issues

- RATS – Commercial interests vs technical capability
- BPA vs PSE Northern Intertie dispute
- Path Allocation of Nomogram issues
- WSCC seems to favor Pro-Rata cuts

NERC movement towards national reliability standards

May tighten requirements for native load service – changes would increase transmission costs