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July 24, 2009

Via Electronic and US Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PACIFICORP Request for a General Rate Revision
Docket No. UE 210

Dear Filing Center:

Enclosed please find the original and five (5) copies of the following testimony on behalf of the Industrial Customers of Northwest Utilities in the above-referenced docket:

Reply Testimony of Randall Falkenberg (ICNU/100) with Exhibits (ICNU 101 – ICNU/104); and

Reply Testimony of Donald Schoenbeck (ICNU/200) with Exhibits (ICNU 201 – ICNU/208).

Also enclosed please find the original and five (5) copies of the following testimony on behalf of the Industrial Customers of Northwest Utilities and the Citizens' Utility Board of Oregon in the above-referenced docket:

Reply Testimony of Michael Gorman (ICNU-CUB/300) with Exhibits (ICNU-CUB 301 – ICNU-CUB/323); and

Reply Testimony of Ellen Blumenthal (ICNU-CUB/400) with Exhibits (ICNU-CUB 401 – ICNU-CUB/403).

Thank you for your assistance.

Sincerely,

/s/ Brendan E. Levenick
Brendan E. Levenick

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Reply Testimony on behalf of the of the Industrial Customers of Northwest Utilities and the Citizens' Utility Board of Oregon upon the parties, on the service list, by causing the same to be deposited in the U.S. Mail, postage-prepaid, and via electronic mail where paper service has been waived.

Dated at Portland, Oregon, this 24th day of July, 2009.

Sincerely,

/s/ Brendan E. Levenick
Brendan E. Levenick

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(W) MCDOWELL & RACKNER PC KATHERINE A MCDOWELL AMIE JAMIESON 520 SW SIXTH AVE - SUITE 830 PORTLAND OR 97204 katherine@mcd-law.com amie@mcdlaw.com	**DEPARTMENT OF JUSTICE** JASON W JONES **(C)** ASSISTANT ATTORNEY 1162 COURT ST NE SALEM OR 97301-4096 jason.w.jones@state.or.us
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

REPLY TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

July 24, 2009

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350.

Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a utility regulatory consultant and President of RFI Consulting, Inc. ("RFI"). I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY RFI?

A. RFI provides consulting services related to electric utility system planning, energy cost recovery issues, revenue requirements, cost of service, and rate design.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit ICNU/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses two issues raised in Mr. Duvall's Second Supplemental Testimony dated June 15, 2009. These proposals concern the procedures applicable to future stand alone Transition Adjustment Mechanism ("TAM") proceedings.

Q. PLEASE EXPLAIN PACIFICORP'S PROPOSAL.

A. Mr. Duvall makes two proposals:

1. Stand alone TAM proceedings should not allow changes in methodologies to be applied, absent a good cause exception.

2. Stand alone TAM proceeding should not reflect the variable cost impacts of new generation unless the Company has owned these resources for two full years prior to the TAM filing date.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A.

1. I agree in part with Mr. Duvall's first proposal, but propose that excluded methodological changes be limited to matters already <u>decided</u> by the Commission in a prior case. Matters not decided by the Commission or not litigated should not be excluded. I also make additional proposals to streamline stand alone TAM proceedings.

2. I agree in part with Mr. Duvall's second proposal, but believe that the new resource exclusion period should be limited to only six months (the amount of time required for the Company to file a full general rate case) in situations where the resource acquisition was not planned far in advance (e.g., Chehalis). In ordinary cases where the new resource has been expected for years (e.g., Lake Side) no exclusion period is justified.

Methodological Changes

Q. PLEASE DISCUSS MR. DUVALL'S FIRST PROPOSAL.

A. I partially agree with the sentiment that stand alone TAM proceedings will be more streamlined and truncated than a general rate case. In fact, there is little choice in the matter for either a TAM starting at the same time as a general rate case ("GRC"), or a TAM conducted on a stand alone basis. Indeed, there is little practical difference between work required to litigate a TAM in either case, but the time to litigate issues in a TAM is shorter than a general rate case.

Assuming the Company were to file a GRC earlier than March 1 of a given year,[1/] the effective schedule for a TAM proceeding is automatically two months shorter than is normally the case for costs recovered via a general rate case. Because Schedule 200 rates have to be adjusted on January 1 of the following year, it is implied that a decision is needed by mid-October. This effectively cuts the last two months out of the schedule for these cases. A TAM proceeding that is filed on a stand alone basis would on April 1, therefore, likely be shorter by at least one more additional month. In the end, power cost issues are decided in two months less than other base rate matters when a TAM is filed at the same time as a GRC. In the case of a Stand Alone TAM, they issues are decided in at least three months less time as a GRC. While there are frequently numerous net variable

[1/] This is the timeline specified as the latest possible date for a GRC filing in the UE 199 stipulation. As Mr. Duvall points out, assuming the Company honors this commitment, it limits the time frame for filing a case to the first two months of the year. Based on recent events, the Company may not file much earlier than March 1.

power costs ("NVPC") issues in TAM proceedings (sometimes more than the non-NVPC issues in a full GRC) and power costs are a very large component of base rates, the TAM process as now implemented provides substantially less time for regulatory review of power costs no matter what format is used. Opposing party's due process rights have already been diminished substantially. Limiting the scope of inquiry would only serve to frustrate the goals of "fair, just and reasonable" rates, and ultimately provide the Company an undeserved advantage.

Q. WILL THE COMPANY PROPOSAL EVEN SUCCEED IN STREAMLINING STAND ALONE TAM PROCEEDINGS?

A. I doubt it. A basic problem is that the Company has refused to clearly specify what it considers a methodological change to be. The Company did not explain what it meant by methodology changes in its testimony. Exhibit ICNU/102, is a copy of the Company's position regarding the issue of methodological changes. This includes copies of ICNU data request ("DR") 7.8 and a number of other questions I asked the Company regarding its proposal. These questions explored various possible scenarios as to what constituted a methodological change in prior cases, what might be considered such a change in the future, and so on. I specifically identified past issues of dispute in TAM cases and whether those were changes in methodology, but the Company refused to answer. ICNU/102, Falkenberg/1-9. It is remarkable that PacifiCorp is seeking to significantly limit the scope of the TAM, but is refusing to provide a working definition of what actually constitutes a change in methodology. PacifiCorp is proposing an "I know it when I see it" definition for methodologies, which the Company will likely interpret in a subjective and one-sided manner. In its response to ICNU DR 7.8, the Company admits it does not have a specific interpretation of this proposal, nor did it provide any guidance as to what constituted a methodological change in prior cases. In every other question I asked, the Company simply referred back to this vague and unresponsive answer.

As a result, I think it is likely that stand alone TAM proceedings will become far more complex and cumbersome under the Company's approach. For each adjustment, there may now be three arguments for the OPUC to decide: 1) is an adjustment or approach proposed by the Company or a party a methodological change; 2) if so, is there good cause to make the change; and 3) is the adjustment appropriate on its merits. I would not be surprised if this means the Commission requires more time than ever to provide its decision, taking time away from other parts of the procedural schedule.

In the end, it would be much simpler if everyone just did their job and let the Commission decide issues on their merits, as they have for several years in the TAM cases. The Commission should understand that it took the parties to the UE 199 stipulation several months of difficult negotiation to arrive at a partial agreement concerning the much simpler questions of workpapers, or of what updates should be allowed in TAM cases. There is nothing to suggest the much broader question of what is a methodology change and what is not, will be easily agreed upon or defined. Thus, undecided issues should not be "eliminated" from consideration because the Company believes it is a "methodological" issue.

Q. DO YOU FORESEE ADDITIONAL PROBLEMS?

A. Yes. A further problem is that Mr. Duvall's Net Power Cost ("NPC") group within the Company often uses data and information prepared elsewhere in the Company. The NPC group may not always fully disclose changes (if known) to the methods used in preparation of various power cost model inputs or assumptions. For example, the

Company made some substantial changes to its hydro modeling approaches in UE 199 and UE 207, introducing hydro forced outage rate modeling and assuming continuation of drought conditions for eastern hydro resources, rather than its traditional normalization technique. Such changes were not fully disclosed by the Company when first introduced in regulatory proceedings and could only be identified through the discovery process. As a result, there is some concern about the ability of parties to "police" this protocol, particularly in a "streamlined" proceeding where there is already less time for discovery and analysis.

Another example concerns electric "swaps." UE 199 was a stand alone TAM proceeding. The Company sought to include the cost of swaps ($275 thousand) for the first time ever in that proceeding. The Company has indicated that they were not included in prior filings because the NPC group was not aware of these transactions.[2/] In the rebuttal phase, the dollar value of the swaps ballooned to over $65 million. At that time, the Company initially refused to provide workpapers for the swaps citing the "highly confidential" nature of a few of the dozens of such contracts. Indeed, the Company did not even reveal the existence of the workpapers when the July filing was made. PacifiCorp has refused to state whether it considers the inclusion of the swaps as a change in methodology. ICNU/102, Falkenberg/10.[3/] In the end, a prohibition against methodology changes could have eliminated a substantial cost element of the Company's filing, simply because the NPC group was not aware of these contracts earlier. Thus, it

[2/] In Utah Docket No. 07-035-93, the Company filed testimony in its rebuttal filing in May, 2008 (around the same time as the April 1, 2008 UE 199 filing) indicating that the electric swaps had been excluded from prior NPC studies by mistake.

[3/] In the DR the Company was asked to identify whether changes made in its rebuttal case in Utah 07-035-93 were methodology changes or not. In that case, the Company included electric swaps for the first time in its rebuttal filing. The Company refused to provide a specific answer to the question.

should be clear that the Company's experts may not even be aware of the full extent of the methodological changes implicit in the data they are using and that they do not always disclose those changes when made. Thus, the Company's proposal is inherently one-sided, in that the Company may make methodological changes but not disclose them, while opposing parties would be required to operate within some rather strict limitations.

Q. IS THERE A DIFFERENCE BETWEEN A METHODOLOGY AND A PROCEDURE?

A. I do not know if the Company's proposal would include changes in procedures. The Commission may face many questions of this sort. A ban on methodological changes raises some subtle questions. In UE 179, UE 191 and UE 199, the Company used a four year period to compute outage rates and other inputs that ended only a few months prior to the filing dates (December 2007 in UE 199, December 2006 in UE 191, and September 2004 in UE 179). In UE 207, the Company used a four year period ending some nine months earlier (June 2008) to compute outage rates. The Company clearly changed its procedures and is now relying on older data in its current TAM proceeding. The question is: does this constitute a methodological change? A party might propose to use the more recent data, in keeping with the Company's past approach of using the most recent outage rate data. It may be necessary for the Commission to decide, whether that is a methodological change or not. If so, what then is the "methodology of record?"

Perhaps it is only a coincidence that the Company's use of the earlier data resulted in $5 million in higher costs due to the fact that forced outage rate improvements in recent months were not factored into UE 207. We will probably never know. However, it does raise the questions of whether the Company will follow the same approach its used in prior cases on a consistent basis, and whether parties will be able to keep track of what data or method has been used in prior cases.

Q. ARE THERE OTHER PRACTICAL DIFFICULTIES YOU FORESEE?

A. Yes. A ban on methodological changes requires documentation concerning the methods currently in use. This means parties and the Company should provide side by side comparisons of each input they compute for whatever assumptions they nominate. As the Company's workpapers are likely little more than a mere fraction of the total documentation underlying their filing, opposing parties will likely never be in a position to prove whether the Company changed its methodologies.

Q. HOW DO YOU KNOW THAT THE COMPANY'S TAM WORKPAPERS ARE ONLY A SMALL PART OF THE UNDERLYING PAPER TRAIL?

A. Some of the inputs used, such as hydro energy, are outputs from other models, such as VISTA. I've reviewed the output for VISTA and it is quite large and opaque. There is no obvious way one could tell if the model was changed. Since VISTA is used elsewhere in the Company for other purposes, changes may be needed to address new circumstances, and it would probably be inappropriate to limit that model given its use in the Company.

Another indicator of the volume of missing documentation can be seen by comparing the workpapers PGE filed in UE 198 supporting its much simpler MONET model inputs. In that case, PGE provided some 667 MB of data in approximately 700 files. PacifiCorp's workpapers consisted of only 210 MB of data and about 60 files. PGE supplied many documents supporting its inputs, which PacifiCorp did not provide. For example, PGE provided studies performed by their wind consultants supporting wind capacity factor assumptions, while PacifiCorp reported only the numerical capacity factor data. One could not tell whether a change in wind assumptions used by PacifiCorp was a methodological change, a change in data, or not from one case to the next. To do so, one would need to do discovery on both the current and prior cases' input assumptions. It might take a motion to compel in order to get the Company to produce such data.[4/]

Q. HOW THEN SHOULD STAND ALONE TAM PROCEEDINGS BE STREAMLINED?

A. I believe that there are several ways in which to accomplish this. First, parties should be precluded from addressing issues that have already been decided by the Commission in prior general rate or TAM cases. Second, the introduction of new types of costs or revenues in a stand alone TAM should not be allowed. For example, the current TAM includes reserve related wind integration costs, but new types of wind integration costs are being discussed, including "day-ahead forecast error" costs, "regulate up" costs, "regulate down" costs, etc. Such new types of costs should be excluded. Likewise, a new transmission contract might result in added wheeling costs and additional wheeling revenues. It would complicate matters, however, if a party proposed to include the added wheeling revenues, as this is not part of the TAM. Unless such a limitation is implemented, then the shortened TAM proceedings will become mired into issues better decided in a full general rate case.

Finally, Commission approved methodologies should be considered only to include methodologies decided in fully litigated proceedings, where the Commission decided the issue or methodology in question. In cases where "black box settlements"

[4/] For example, in UE 199, the Company initially refused to provide workpapers underlying the July 2008 update of the UE 191 transmission wheeling costs. A party may have to go to extreme lengths to discover whether methodology changes had been made or not.

were employed or an issue was not litigated, no approved methodology should be presumed in future cases.

Q. PLEASE EXPLAIN YOUR LAST POINT.

A. In some cases, such as UE 199, parties use a "black box" settlement to decide overall rate increase levels, but not specific contested issues. Such cases provide no guidance as to the methodologies to be employed in future cases. As an example, in UE 199, the Company introduced hydro forced outage rate modeling, which was opposed by Staff. Consequently, there should be no presumption as to which constitutes the "methodology of record" because the settlement did not address the issue. It would be a poor policy to simply assume that any method the Company files at any stage of a case constitutes accepted practice. Whether contested by parties or not, a methodology employed by the Company that was used in a "black box" settled case should be assumed to carry no more weight than any method proposed by opposing parties.

The same should be true of methodologies used by the Company that were not litigated in prior cases. Simply because a problem is not discovered, or significant enough to warrant comment, does not mean parties should be banned from addressing it later. This is very important because Staff and intervenors do not challenge all potential flaws with PacifiCorp's power cost model in each case. Many errors are not apparent or may have such a small monetary value that they are not challenged.

Q. HOW FREQUENTLY HAVE PARTIES PROPOSED ADJUSTMENTS THAT ENTAIL A CHANGE IN METHODOLOGY IN RECENT CASES?

A. Exhibit ICNU/103 provides a list of issues raised by parties to recent TAM cases. The list shows that the great majority of issues contested could be considered methodological changes. It is impossible to determine if the Company views these as changes in methodology since the Company refused to state its position in discovery responses. In some cases, the issues contested were changes to methodologies proposed by the Company. Before limiting the TAM, the Commission would need to consider whether these types of issues should be precluded in future cases. I have requested that PacifiCorp and CUB identify the issues which they believe were methodology changes (in both workshops and discovery), and which were not, but they have consistently refused to do so.

Q. WHY HAVE THERE BEEN SO MANY METHODOLOGY RELATED ISSUES IN PACIFICORP RATE CASES?

A. GRID is a "homemade" power cost model built specifically for the Company. It has been in use for only a few years, and during that time numerous errors and other problems have been uncovered. In UE 199, for example, I pointed out a fundamental error in the model related to commitment logic. It is arguable as to whether the Company ever disclosed this error, and while it did accept a few adjustments from time to time to address certain symptoms of the problem, its significance became much greater when the Company added new combined cycle power plants to the system. In UE 199, the Company finally admitted the full extent of the error and accepted an adjustment of more than $26 million (Total Company) to partially address the issue. Re PacifiCorp, OPUC Docket No. UE 199, Rebuttal Testimony of Gregory Duvall, PPL/107 Duvall/1 (July 25, 2008). This problem remains unsolved in the model and demonstrates that the GRID model contains other significant flaws. While some of these flaws may not be known now, or may have a small economic impact under current conditions, parties should not be precluded from addressing them in future TAM proceedings. The great majority of the other adjustments in prior cases have been intended to deal with some aspect of the

GRID model that is not sufficient for its intended purposes. Limiting methodological changes in future cases could well result in "unfair, unjust and unreasonable" rates.

Q. PLEASE EXPLAIN EXHIBIT ICNU/104.

A. In this exhibit I have delineated the issues I addressed in UE 207 according to whether they were methodological disputes, correction of errors, of simply disagreements about certain inputs. There was some degree of subjectivity in this, as some issues contained multiple elements. However, I believe the exhibit fairly depicts a reasonable interpretation of the adjustments applicable to each category. In the end, the exhibit shows that 87% of the dollar amount of issues ($24 million) in UE 207 are disputes concerning the proper methodology to apply. Very few of these adjustments are simple error corrections or disagreements over inputs. The point of this is that, as in prior cases, methodological disputes are a major aspect of the discussion of power costs in UE 207. Because of the dynamic nature of PacifiCorp system power costs, methodological issues can be expected to continue to evolve and be important in future cases, whether they are stand alone proceedings, or conducted while a general rate case is also taking place. It should also be clear that there is substantial disagreement as to the proper techniques for power cost modeling, present in PacifiCorp cases.

<u>New Resources</u>

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL RELATED TO THE TREATMENT OF VARIABLE COSTS OF NEW RESOURCES IN STAND ALONE TAM CASES?

A. No. While, the Company raises a seemingly valid concern, I disagree with the solution. I only partly agree that PacifiCorp's concern is valid because the Company fails to recognize that the TAM is a unique regulatory mechanism that allows the Company an annual ability to increase rates through single issue ratemaking. The TAM allows

PacifiCorp to increase rates even if its other costs are decreasing or it is otherwise earning its rate of return. The purpose of the TAM was to value PacifiCorp's NVPC for direct access, and the inclusion of the NVPC of new resources is consistent with that purpose. PacifiCorp's proposal demonstrates that PacifiCorp does not view the TAM as a way to facilitate direct access, but as an opportunity to increase rates on an annual basis.

Q. WHAT IS PACIFICORP'S PROPOSAL?

A. Mr. Duvall proposes any new resource (except those eligible for Renewable Resources Automatic Adjustment Clause ("RAC") recovery) be excluded from the TAM, unless the Company acquired or completed the resource two years prior to the TAM filing date. For example, the Company acquired Chehalis in late 2008. This means that (absent a full GRC) it would not be included in a stand alone TAM case filed until April 2011.

Q. WHAT IS YOUR PROPOSAL?

A. The Company should have time to prepare and file a new GRC to include new resources. However, it should not take two full years to accomplish that, and there is a distinction between special acquisitions (such as Chehalis) and self built options such as Lake Side or other resources acquired through an Request for Proposal ("RFP") process.

I recommend that the Company be required to reflect the new resource in a stand alone TAM so long as the Company has had the opportunity to file a GRC but chose not to do so. I believe a six month preparation period is adequate for a "special acquisition" GRC.[5/] For example, if the Company acquired a new resource before September of a given year, it could file a GRC by March 1 of the following year. A new resource acquired outside of any Integrated Resource Plan or RFP process such as Chehalis is

[5/] I have requested the Company's schedules for filing rate cases, but the Company refused to provide them citing "privilege." Thus, PacifiCorp has not provided information about how long it actually takes to prepare and file a general rate case.

arguably an unpredictable event accompanying a special opportunity. That being the case, it should be recognized that the Company may not immediately be prepared to file a GRC in conjunction with the new resource acquisition.

However, this procedure should only apply in <u>special situations</u>, such as Chehalis and should not be the norm. For ordinary resources, such as Lake Side, the Company certainly knows far in advance when it will be completed and can plan a GRC to request cost recovery. In such cases, there is no reason why the Company should not be able to obtain timely cost recovery <u>if</u> justified. If the Company does not file such a case when a major new resource comes online, I think there is no basis to assume anything other than that the Company is earning a fair rate of return.

Q. ARE THERE ANY OTHER ASPECTS OF THIS ISSUE?

A. Mr. Duvall discussed new resource additions, but did not consider the matter of resource subtractions. In 2008, for example, the Company terminated the West Valley lease, saving itself around $15 million per year. The Company did not wait, however (as it now proposes), to keep West Valley in the resource mix until a GRC had been conducted to remove its fixed costs from rates. Likewise, the Company has assumed retirement of various hydro resources in recent years, and has reflected these in the TAM, without waiting for a GRC. I suggest that whatever principle the Commission employs, it should apply symmetrically to newly acquired or completed assets and to resource reductions such as terminations, retirements, etc.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU/101

QUALIFICATIONS OF RANDALL J. FALKENBERG

July 14, 2009

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity. In addition, I have been involved in many projects over the past several years concerning the modeling of market prices in various regional power markets.

In January 2000, I founded RFI Consulting, Inc. whose practice is comparable to that of my former firm, J. Kennedy and Associates, Inc.

The testimony that I present is based on widely accepted industry standard techniques and methodologies, and unless otherwise noted relies upon information obtained in discovery or other publicly available information sources of the type frequently cited and relied upon by electric utility industry experts. All of the analyses that I perform are consistent with my education, training and experience in the utility industry. Should the source of any information presented in my testimony be unclear to the reader, it will be provided it upon request by calling me at 770-379-0505.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance", December 1995 Issue

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Phase-in of nuclear unit.
2/85	I-840381	PA	Phila. Area Ind. Energy Users' Group	Philadelphia Electric Co.	Economics of cancellation of nuclear generating units.
3/85	Case No.	KY	Kentucky Industrial	Louisville Gas	Economics of cancelling fossil

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
	9243		Utility Consumers	& Electric Co.	generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General & Georgia Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7-Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86	9437/613	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87-013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.
10/88	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of gas sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346	MI	Association of Businesses Advocating Tariff Equity (ABATE)	Consumers Power	DSM Policy Issues.
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico Utility Counsel	Imprudence disallowance. Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT Plant	CCS	PacifiCorp	Certification of Peaking
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS		PacifiCorp Net power costs
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause
05/05	UE-170	OR	ICNU	PacifiCorp	Power Cost Modeling
7/05	UE-172	OR	ICNU	Portland General	Power Cost Modeling
08/05	UE-173	OR	ICNU	PacifiCorp	Power Cost Adjustment
8/05	UE-050482	WA	ICNU	Avista	Power Cost modeling, Energy Recovery Mechanism
8/05	31056	TX	OPC	AEP Texas Central	Stranded cost true-up.
11/05	UE-05684	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation, PCA

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
2/06	05-116-U	AR	AEEC	Entergy Arkansas	Fuel Cost Recovery
4/06	UE-060181	WA	ICNU	Avista	Energy Cost Recovery Mechanism
5/06	22403-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
6/06	UM 1234	OR	ICNU	Portland General	Deferral of outage costs
6/06	UE 179	OR	ICNU	PacifiCorp	Power Costs, PCAM
7/06	UE 180	OR	ICNU	Portland General	Power Cost Modeling, PCAM
12/06	32766	TX	OPC	SPS	Fuel Reconciliation
1/07	23540-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
2/07	06-101-U	AR	AEEC	Entergy Arkansas	Cost Allocation and Recovery
2/07	UE-061546	WA	ICNU/Public Counsel	PacifiCorp	Power Cost Modeling, Jurisdictional Allocation, PCA
2/07	32710	TX	OPC	EGSI	Fuel Reconciliation
6/07	UE 188	OR	ICNU	Portland General	Wind Generator Rate Surcharge
6/07	UE 191	OR	ICNU	PacifiCorp	Power Cost Modeling
6/07	UE 192	OR	ICNU	Portland General	Power Cost Modeling
9/07	UM 1330	OR	ICNU	PGE, PacifiCorp	Renewable Resource Tariff
10/07	06-152-U	AR	AEEC	EAI	CA Rider, Plant Acquisition
10/07	07-129-U	AR	AEEC	EAI	Annual Earnings Review Tariff
10/07	06-152-U	AR	AEEC	EAI	Purchase of combined cycle power plant.
04/08	26794	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Case

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU/102

ICNU DATA REQUESTS 7.8 - 7.56 TO PACIFICORP AND PACIFICORP'S SUBSEQUENT DATA RESPONSES TO ICNU DATA REQUESTS 7.8, 7.9, AND 7.56

July 24, 2009

ICNU Data Request 7.8

Please refer to the June 1, 2009 all-party Stipulation on guidelines governing future TAM proceedings ("Guidelines"). The Guidelines provided that the Parties would address in Docket UE 210:

> whether (1) changes in methodologies utilized in the calculation of net power costs, such as those used to calculate normalized hydro or forced or planned outage rates or calculation issues resolved by the Commission, will be permitted in stand-alone TAM proceedings; and (2) a stand-alone TAM should include the variable costs of new generation resources if the Company will not recover the fixed costs of the generation resource in the TAM rate effective period.
>
> In all of the questions below, where "change in methodology" is discussed, please answer the question under the assumption that the technique, data input, or modeling approach being discussed was introduced for the first time in a specific case.

Please explain PacifiCorp's interpretation of the term "methodologies" quoted in the above passage.

Response to ICNU Data Request 7.8

The Company does not have a specific interpretation of the term "methodologies" quoted in the above passage and it has not analyzed its previous filings or the filings of others to determine what might or might not constitute a methodology change. As a general matter, the Company believes that in this context, "methodologies" includes the calculation of normalized hydro and forced or planned outage rates and other significant net power costs modeling changes and excludes issues related to the prudence of contracts, the appropriate modeling of contracts and known and measurable changes to inputs for existing methodologies. The Company expects that the Commission will provide further direction on this issue in UE 210. In the future, if changes in methodologies utilized in the calculation of net power costs are not permitted in a stand-alone TAM proceeding and there is a dispute that can not be resolved by the parties, the Company expects that the Commission will ultimately make the interpretation for the specific item(s) at issue.

UE-210/PacifiCorp
June 19, 2009
ICNU 7th Set Data Request 7.9

ICNU Data Request 7.9

Would changing the calculations, formulae of input data to the GRID model constitute a change in methodology in PacifiCorp's view? Please explain.

Response to ICNU Data Request 7.9

Please refer to the Company's response to ICNU Data Request 7.8.

7.10 Would changing the power cost model from GRID to another model constitute a change in methodology? Please explain.

7.11 Are there any specific inputs to the power cost model that the Company believes could not be changed without changing the methodology? Please explain.

7.12 Assume hypothetically that the Company computed a second order heat rate curve for a particular power plant. Would a change in the heat rate curve to a linear model, or a model with higher order terms constitute a change in methodology? Please explain.

7.13 Assuming the Commission had already decided that the methodologies used in the TAM would be based solely on those used in the last general rate case, what case would determine the methodologies that would apply in an April 2010 TAM proceeding? Please explain whether it would be UE 179.

7.14 Please refer to the attached list of issues addressed by CUB, Staff and ICNU in prior TAM proceedings. Please identify those issues which the Company believes constituted a proposal to change the methodology used to compute power costs from prior TAM or GR cases.

7.15 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the modeling change related to Cal ISO fees and SP 15 transmission constitutes a change in methodology. If not, explain why not.

7.16 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the Company's inclusion of Short Term Firm transmission constitutes a change in methodology. If not, explain why not.

7.17 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the modeling change related to Company's calculation of screens used to eliminated uneconomic generation by combined cycle gas plants constitutes a change in methodology from that used in UE 199. If not, explain why not.

7.18 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the modeling change related to Company's calculation of screens used to eliminated uneconomic generation by the Gadsby gas plants constitutes a change in methodology from UE 199. If not, explain why not.

7.19 In UE 191 the Company adopted a methodology for elimination of certain costs related to call option contracts related to the issue of extrinsic value. Does the fact that the Company did not utilize this approach in UE 207 constitute a change in methodology from UE 191? Please explain the answer.

7.20 Assume hypothetically that the Company decided it would include the outages determined by the OPUC in UE 191 as imprudent from the four year rolling average used in TAM cases. Would that be considered to be a change in methodology?

7.21 Would elimination of imprudent forced outages from the four year rolling average used in TAM cases be considered by the Company to be a change in methodology?

7.22 Would a change in the level or data and formulae used to compute market caps be considered by the Company to be a change in methodology.

7.23 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the modeling changes related to the Company's assumptions concerning the modeling of the Seattle City Light Stateline contract constitutes a change in methodology. If not, explain why not.

7.24 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the modeling change related to Company's modeling of the Bear River (east side) hydro resources constitute a change in methodology. If not, explain why not.

7.25 Assume that the Company had a hydro resource that had experienced drought conditions for several years, and that it was expected it would take more than a year to return to normal operation even with normal precipitation. Would the Company consider changing the modeling of that resource in GRID to reflect draught, rather than a 40 year normalized condition amount to a change in methodology for TAM cases? Please explain.

7.26 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the modeling change related to Company's duct firing resources constitute a change in methodology. If not, explain why not.

7.27 Assume hypothetically that an error was uncovered in the GRID model in another state, and that the Company implemented changes in logic or data inputs (e.g., screens for the commitment logic error) to correct the error. Please explain whether correcting the error would constitute a change in methodologies.

7.28 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the inclusion of start up O&M costs constitutes a change in methodology from the approach used in UE 191. If not, please explain why not.

7.29 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the inclusion of start up O&M costs constitutes a change in methodology from the approach used in UE 199. If not, explain why not.

7.30 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the inclusion of start up fuel costs for Currant Creek and Lake Side constitutes a change in methodology from the approach used in UE 191. If not, explain why not.

7.31 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the inclusion of start up fuel costs for Gadsby units (steam and CT) constitutes a change in methodology from the approach used in UE 199. If not, explain why not.

7.32 In UE 199, the Company abandoned the use of the monthly outage rate calculation for GRID in its rebuttal testimony. Does the Company believe this constituted a change in methodology as compared to the Company's direct case filing? Please explain.

7.33 In UE 199, the Company abandoned the use of a weekend/weekday split outage rate calculation for GRID in its rebuttal testimony. Does the Company believe this constituted a change in methodology as compared to the Company's direct case filing? Please explain.

7.34 Assume that the Company used a spreadsheet to compute inputs to GRID, and that it was discovered that spreadsheet contained an error in a formula, rather than an error in data. Would correcting that error constitute a change in methodology used in a stand alone TAM case had the incorrect spreadsheet been used in the most recent TAM case processed at the same time as a general rate case.

7.35 Was the Company's introduction of hydro forced outage rates in UE 199 a change in methodology? Please explain.

7.36 In UE 191 the Company did not include its ramping adjustment in the calculation of forced outage rates. In UE 199 the Company included the ramping adjustment. Was this a change in methodology or a correction of an error?

7.37 In UE 199, the Company abandoned the ramping adjustment for gas units in GRID in its rebuttal testimony. Does the Company believe this constituted a change in methodology as compared to the Company's direct case filing? Please explain

7.38 In UE 207 the Company included the Long Hollow wind farm as part of its wind integration expense. Since Long Hollow is a project for which the Company wheels power, rather than purchases energy, or has a storage and exchange agreement and therefore differs from other third party wind projects, does inclusion of that project constitute a change in methodology?

7.39 In UE 199 the Company included wind integration expenses in GRID for the first time. Did that constitute a change in methodology? Please explain.

7.40 If the Company decided to include new types of wind integration expenses other than those currently modeled in GRID (i.e., day ahead forecast error, regulating up or regulating down, etc.) would that amount to a change in methodology?

7.41 Would any change from the wind integration currently modeled in GRID (premised on the $1.1/MWH 2007 cost level) amount to a change in methodology?

7.42 Would inclusion of BPA wind integration charges in a stand alone TAM, if such charges were not included in the prior TAM processed concurrently with a general rate case be considered a change in methodology.

7.43 In UE 199 the Company included additional wind projects in the wind integration expense line in its rebuttal filing as compared to its direct filing. Did that constitute a change in methodology?

7.44 In UE 199 the Company used a projection it prepared based on a specific spreadsheet for the computation of the Grant County revenue credit in GRID in its direct case filing. That spreadsheet depended on forward price curve inputs. In the final update, the Company relied upon a different approach not based on updating the forward price curve, but rather based on new data it was provided by Grant County. Was this a change in methodology?

7.45 UE 199 was settled based on a typical "Black Box" settlement. Assume that the Commission decided that methodologies could not be changed in Stand Alone TAM proceedings, and the UE 207 was filed stand-alone. Are there any methodology changes the Company filed in UE 207 that it believes would not be appropriate or allowable? Please explain.

7.46 Assume that UE 207 is settled in "Black Box" manner comparable to UE 199. Would the Company's position in the subsequent TAM filed in 2010 (assuming it were "stand alone") that the Company's initial or rebuttal filings in UE 207 constitute the methodologies that could not be changed in the 2010 case?

7.47 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the elimination of the hydro Wet and Dry scenarios constitutes a change in methodology. If not, explain why not.

7.48 Assume that in UE 207 Mr. Falkenberg proposed to change the modeling of the SMUD contract from the Company's filed request to the method approved by the Utah Public Service Commission in Docket No. 07-035-93 (based on normalizing the monthly takes based on 4 years of history rather than the Company's modeling approach). Would that constitute a change in methodology?

7.49 Please refer to Mr. Falkenberg's direct testimony in the current Wyoming PCAM proceeding, Table 1. Please identify each of the adjustments proposed by Mr. Falkenberg, or by Mr. Widmer that the Company believes constitutes a change in methodology from the Company's direct filing in that case.

7.50 Please refer to Mr. Falkenberg's direct testimony in Utah Docket No. 07-035-93, Table 1. Please identify each of the adjustments which the Company believes constitute a change in methodology from the Company's direct filing in that case.

7.51 Please refer to Mr. Falkenberg's direct testimony in Utah Docket No. 08-035-38, Table 1. Please identify each of the adjustments which the Company believes constitute a change in methodology from the Company's direct filing in that case.

7.52 Please compare Mr. Duvall's direct and rebuttal testimony in Utah Docket No. 08-035-38. Please identify all adjustments made to the GRID model between his direct and rebuttal filing which the Company considers to be a change in methodology.

7.53 Please compare Mr. Duvall's direct and rebuttal testimony in Utah Docket No. 07-035-93. Please identify all adjustments made to the GRID model or its inputs between his direct and rebuttal filing which the Company considers to be a change in methodology.

7.54 Please compare Mr. Duvall's direct and rebuttal testimony in Oregon Docket UE 199. Please identify all adjustments made to the GRID model or its inputs between his direct and rebuttal filing which the Company considers to be a change in methodology.

7.55 Please compare Mr. Widmer's direct and rebuttal testimony in Oregon Docket UE 191. Please identify all adjustments made to the GRID model between his direct and rebuttal filing which the Company considers to be a change in methodology.

7.56 Assume hypothetically that the Company used a specific methodology in computing certain aspects of its TAM power cost studies and that the Company forgot to include the methodology in a TAM proceeding filed concurrent with a general rate case. Would correcting that oversight be considered a change in methodology in a future stand alone TAM proceeding?

7.57 Consider the Company's Hydro Reserve Input Parameter used in GRID. Please identify all specific workpapers or analysis which it can provide to support those inputs. If the Company has no specific workpapaers or analysis, would this imply that any changes to such inputs would constitute a change in methodology by the Company? For example, if a technique were used to compute such inputs from historical data or from operational data, would that be a change in methodology?

7.58 Consider the Company's Start Up O&M expense input used in GRID and in the screening methodology. Please identify all specific workpapers or analysis which it can provide to support those inputs. If the Company has no specific workpapaers or analysis, would this imply that any changes to such inputs would constitute a change in methodology by the Company? For example, if a technique were used to compute such inputs from historical data or from operational data, would that be a change in methodology?

7.59 Explain the methodology used by the Company to determine the minimum loading levels modeled in GRID. Please be specific and provide the method used for each generating unit. Would any changes to these inputs be considered a change in methodology by the Company?

7.60 When the Company changed the minimum capacity of the Cholla plant from 150 MW to 250 MW due to the sodium depletion problem did that constitute a change in methodology? If not, explain why not.

7.61 When the Company changed the maximum capacity of Dave Johnston unit 3 from 230 to 220, MW did that constitute a change in methodology? If not, explain why not.

7.62 When the Company increased the minimum capacity of Currant Creek to 340 MW in GRID did that amount to a change in methodology. If not, explain why not.

7.63 Assume that the Company encounters a transmission link limit change that prevents 100% of the capacity of a thermal unit from being delivered to the rest of the PacifiCorp system, or to outside markets. Would reducing the capacity of that unit to never exceed the available transmission capacity amount to a change in methodology? Would inputting a reduction to the size of the associated transmission links be a change in methodology?

7.64 Explain the methodology used by the Company to determine the regulating margin requirements (both minimum and maximum) modeled in GRID. Would any changes to these inputs be considered a change in methodology by the Company?

7.65 Refer to the March 2009 filing in UE 207 made by the Company. Please explain whether the changes to the regulating margin input assumptions constituted a change in methodology as compared to those used in UE 199. If not, explain why not.

7.66 Would the Company consider correcting an error of any kind, whether it entailed changes to the method used to compute GRID inputs, changes in the Net Power Cost report file (the excel file) or the GRID model itself to be a change in methodology? Are there any kinds of error corrections that would not amount to a change in methodology?

7.67 Would the Company consider changing the reserve capability inputs for a power plant modeled in GRID so that it could no longer carry spinning reserves, but could carry 10 minute reserves to be a change in methodology?

7.68 Please provide a list of all methodologies currently used in GRID which the Company contemplates could not be changed in stand alone TAM proceedings assuming that the Commission adopted a principle that changes in methodologies would not be allowed in such cases.

7.69 Provide a list of all methodologies that the Company currently uses in GRID.

7.70 Does the Company believe there is any difference between a methodology used in computing power costs in a TAM case and modeling assumptions or GRID inputs? For example, would modeling assumptions related to various call option contracts be considered as methodological in nature or merely input assumptions? Would use of historical data to determine patterns of usage of call option contracts be considered a change in methodology?

7.71 Would correction for a commitment logic error for call options be a change in methodology in a stand alone TAM if in the prior TAM processed with a full GRC, no call option contracts were subject to the commitment logic error? Does the absence of need for correction to a specific kind of logic error in a GRC concurrent case preclude correction of that type of error in subsequent stand alone cases?

7.72 Assume that the Company decided to model the Black Hills contract as taking delivery in different locations from those assumed in UE 199, based on the actual delivery patterns for the contract. Would this constitute a change in methodology?

7.73 In UE 191, the Company introduced assumed escalation rates for BPA transmission contracts modeled in GRID in the rebuttal filing. In the Company's view, did this amount to a change in methodology from the filing made in the direct case?

7.74 In UE 191, the Company included the Hermiston losses in the rebuttal filing, but not in its direct case. Did this amount to a change in methodology from its direct case filing, or merely the correction of an error?

7.75 Assume that the Company discovered in a 2010 TAM case that it had not included a situation similar to the Hermiston losses but that it had not included these losses in UE 207. Would this constitute a change in methodology?

7.76 In the December 2008 UE 199 final update the Company corrected an incorrect calculation of the prices for the Oregon wind QFs based on use of tariff rates rather than some other assumed numbers. Did this amount to a change in methodology?

7.77 Was the inclusion of an adjustment for sales growth in UE 199 a change in methodology as compared to UE 191 or UE 179?

UE-210/PacifiCorp
June 19, 2009
ICNU 7th Set Data Request 7.56

ICNU Data Request 7.56

Assume hypothetically that the Company used a specific methodology in computing certain aspects of its TAM power cost studies and that the Company forgot to include the methodology in a TAM proceeding filed concurrent with a general rate case. Would correcting that oversight be considered a change in methodology in a future stand alone TAM proceeding?

Response to ICNU Data Request 7.56

Please refer to the Company's response to ICNU Data Request 7.8.

Well BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU/103

LIST OF ISSUES RAISED
BY PARTIES TO RECENT TAM CASES

July 24, 2009

Exhbit ICNU/103
UE 191 and 199 Issues

UE 191 Issues

Party	Issue	Type of Adjustment	
CUB	Reject GRID Model Changes	Contest Company methodogy change	M
CUB	Eliminate Hermiston Loss Adjustment	Error Correction	E
CUB	Update Embedded Cost Differential	Methodology change	M
Staff	Excess Operating Reserves	Error correction	E
Staff	Trading Margins	Methodology change	M
Staff	Increase Carbon Plant Capacity Factor to UE 179 levels	Methodology change	M
ICNU	GP Camas Price	Methodology change	M
ICNU	Extrinsic Value Call Options	Methodology change	M
ICNU	Excecss Reserves (3 issues)	Error correction	E
ICNU	CT Reserve Capability	Error correction	E
ICNU	W-E Reserve Transfer	Error correction	E
ICNU	Hydro Modeling (Vista) Adj.	Methodology change	M
ICNU	Reverse Station Service	Methodology change	M
ICNU	Remove Imprudent Outages	Prudence	P
ICNU	Reverse DJ-3 Derate	Contest Input Change	I
ICNU	Cholla 4 Minimum	Contest Input Change	I
ICNU	Uneconomic CT Operation	Methodology change	M
ICNU	Planned Outages > 4 Year Average	Error correction	E
ICNU	NPC In Rates Adjustment	Error correction	E

Ue 199 Issues

Staff	Load Growth Adjustment	Methodology change	M
Staff	Ancillary Service Revenue	Methodology change	M
Staff	Little Mountain Steam Revenue	Methodology change	M
Staff	Wind Integration - Storage	Methodology change	M
Staff	Hydro Forced Outage Rates	Methodology change	M
Staff	Rolling Hills Capacity Factor	Prudence	P
ICNU	Uneconomic Currant Creek Operation	Methodology change	M
ICNU	Uneconomic Lakeside Operation	Methodology change	M
ICNU	Call Options (Uneconomic Generation)	Contest Company methodogy change	M
ICNU	Hermiston Loss Adjustment (Data Error)	Error correction	E
ICNU	SMUD Contract Shape	Methodology change	M
ICNU	SMUD Contract Index Pricing	Methodology change	M
ICNU	Black Hills Contract Shape	Methodology change	M
ICNU	Biomass Non Gen Agreement -	Methodology change	M
ICNU	Planned Outage Schedule	Methodology change	M
ICNU	Median Hydro	Methodology change	M
ICNU	48 Hour vs. 56 Hour Outage Rate	Error correction	E
ICNU	Currant Creek EFOR	Error correction	E
ICNU	Gadsby Steam Ramping (double count)	Contest Company methodogy change	M
ICNU	Reverse Ramping	Contest Company methodogy change	M
ICNU	Reverse Monthly outage modeling	Methodology change	M
ICNU	Weekend Allocation of Maintenance Outages	Methodology change	M
ICNU	PGE Derate Modeling Method	Methodology change	M
ICNU	Wind Integration Charges	Contest Company methodogy change	M
ICNU	Non Firm Transmission	Methodology change	M
ICNU	Goodnoe Transmission Pro Forma	Methodology change	M
ICNU	Cal ISO Wheeling Fee	Methodology change	M
ICNU	Transmission Imbalance	Methodology change	M
ICNU	SP 15 (Alternate to Non Firm)*	Methodology change	M
ICNU	NPC In Rates Adjustment (Sales Growth)	Methodology change	M

Exhbit ICNU/103
UE 191 and 199 Issues

		Total		STAFF		ICNU		CUB	
Total	Methodology Changes	35	71%	7	78%	26	70%	2	67%
	Error Corrections	10	20%	1	11%	8	22%	1	33%
	Prudence	2	4%	1	11%	1	3%	0	0%
	Input Assumption	2	4%	0	0%	2	5%	0	0%
	Total	49	100%	9		37		3	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU/104

CLARIFICATION OF UE 207 ISSUES

July 24, 2009

Exhibit 104: Table 1
Summary of Recommended Adjustments - $

	Total Company	Est. Oregon Jurisdiction	
		SE 25.00%	
		SG 26.88%	
I. GRID (Net Variable Power Cost Issues)			
PacifiCorp Request NPC	1,100,545,210	$272,967,396	
A. GRID Market Caps			
A.1 GRID Market Caps	(18,154,991)	(4,709,314)	M
B. GRID Commitment Logic Error			
B.1 Correct Improper Screens	(2,785,796)	(722,622)	M
B.2 Remove Ineligible O&M Costs	(1,970,498)	(511,137)	M
B.3 Start Up Fuel Energy Value	(3,937,202)	(1,021,291)	M
C. Long Term Contract Modling			
C.1 Call Option Sales Contracts	(5,746,259)	(1,490,551)	M
C.2 Biomass	(600,411)	(155,744)	M
C.3 Morgan Stanley Call Options	(2,641,879)	(685,290)	M
C.4 GP Camas	(808,782)	(209,794)	M
D. Hydro Modeling			
D.1 Hydro Input Corrections	(7,704,863)	(1,998,603)	M
E. New Resource Modeling			
E.1 Chehalis Modeling	(197,920)	(51,339)	I
E.2 Mountain Wind QF	(1,575,114)	(408,577)	I
F. Transmission Modeling			
F.1 Cal ISO Fees	(11,175,680)	(2,898,916)	M
F.2 Non Firm Transmission	(2,470,754)	(640,901)	M
F.3 STF Transmission Link Test Year Synchronization	(8,151,766)	(2,114,527)	M
F.4 Other Transmission Adjustments	(1,309,897)	(339,781)	E
G. Other NVPC Adjustments			
G.1 Regulating Margin	(3,081,757)	(799,392)	E
G.2 Thermal Generator Performance Inputs	(657,502)	(170,553)	E
G.3 Other Wind Resource Contracts	(2,032,116)	(527,121)	E
G.4 Bridger Coal EITF No. 04-6	(12,415,437)	(3,220,502)	M
H. UM 1355 and Other Outage Rate Modeling Issues			
H.1 Planned Outage Schedule	(2,488,797)	(645,582)	M
H.2 Outage Rate WE WD	(1,334,547)	(346,175)	M
H.3 Ramping	(2,092,834)	(542,871)	M
H.4 Minimum Loading and Deration	(4,170,652)	(1,081,846)	M
H.5 Combined Cycle Plant Outage Rates	(2,885,371)	(748,451)	M
H.6 Other Outage Rate Adjustments	(658,089)	(170,705)	M
I. COMPANY CORRECTIONS			
I.1 Unverified GRID Corrections	(4,539,569)	(1,177,541)	E
Subtotal NVPC Adjustments -	(105,588,484)	(27,389,125)	
Allowed - Final GRID Result*	994,956,725	245,578,271	

Analysis of Issues:

Methodological Disputes	M	(23,914,821)	87%
Error Corrections	E	(3,014,388)	11%
Input Changes	I	(459,916)	2%
	Total	(27,389,125)	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

REPLY TESTIMONY OF DONALD W. SCHOENBECK

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

July 24, 2009

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald W. Schoenbeck. I am a member of Regulatory & Cogeneration Services, Inc. ("RCS"), a utility rate and economic consulting firm. My business address is 900 Washington Street, Suite 780, Vancouver, WA 98660.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I've been involved in the electric and gas utility industries for over 35 years. For the majority of this time, I have provided consulting services for large industrial customers addressing regulatory and contractual matters. I have appeared before the Oregon Public Utility Commission (the "Commission" or "OPUC") on many occasions since 1984. A further description of my educational background and work experience can be found in Exhibit ICNU/201 in this proceeding.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including PacifiCorp (or the "Company").

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. I will discuss PacifiCorp's Marginal Cost Analysis ("MCA") presented as Exhibit PPL/907 and the Company's proposed rate spread presented in Exhibit PPL/1002. My testimony will not address revenue requirement issues. ICNU is submitting testimony of other witnesses regarding cost of capital and other matters.

Q. PLEASE BRIEFLY SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS ADDRESSED IN THIS TESTIMONY.

A. I recommend several changes to the MCA to more accurately capture the long run incremental cost of serving PacifiCorp's Oregon customers. The specific recommendations are:

1. Separate loss factors should be applied to metered energy and demand values.
2. Loss factors should be based on the facilities used by the customer.
3. Peak demands should be derived from hourly load research data for the test period.
4. Marginal cost analysis requires a proper matching between the per unit marginal cost assignment and the cost causation unit. PacifiCorp's MCA greatly understates capacity related costs by the extensive use of 12 monthly coincident peaks ("12CP") for determining all marginal demand-related costs.
    a. The marginal cost of distribution transformers should be calculated using customer maximum peak demands.
    b. The marginal demand-related cost of distribution substations and feeders should be calculated using class non-coincident peaks ("1 NCP").
    c. Marginal demand-related transmission costs should be calculated using winter peak load levels ("W CP").
    d. Marginal demand-related generation costs should be calculated using both winter and summer peak load values ("W/S CP").
5. In calculating the marginal costs of distribution feeders, a commitment-related component should be part of every branch segment.

The following table indicates the cost-based increases from incorporating all of my recommendations as compared to the Company's results.

Cost-Based Increase Comparison
(Prior to Mitigation - $000s)

Major Schedule	PacifiCorp	ICNU	Difference	PacifiCorp Increase	ICNU Increase
4	$40,169	$43,502	$3,333	8.5%	9.2%
23 Sec	$9,305	$15,685	$6,385	10.2%	17.3%
23 Pri	$43	$49	$6	43.1%	49.7%
28 Sec	$18,419	$21,288	$2,870	14.8%	17.1%
28 Pri	$131	$73	-$57	11.6%	6.5%
30 Sec	$11,520	$11,646	$127	15.7%	15.9%
30 Pri	$687	$663	-$23	12.9%	12.5%
48 Sec	$5,535	$2,619	-$2,916	15.4%	7.3%
48 Pri	$13,635	$7,018	-$6,617	17.6%	9.1%
48 Trans	$3,469	$1,646	-$1,824	19.9%	9.5%
41	$2,409	$2,097	-$312	16.8%	14.6%
51	$1,909	$942	-$967	54.7%	27.0%
Total:	$107,229	$107,229	$0	11.7%	11.7%

With regard to rate spread in this proceeding, ICNU concurs with the Company that where possible, the rates should be based on the unbundled MCA results. However, the appropriate study to use as a starting point for rate spread purposes is the ICNU MCA presented in this testimony. ICNU also agrees with the Company that a rate spread cap of 1.5 times the overall system average percentage increase is generally appropriate to mitigate the price impact, although we propose a slightly different implementation method. Specifically, the Company's "present base rates" set forth in Exhibit PPL/1002 include the Transition Adjustment Mechanism amount filed for on January 1, 2010 in UE 207. We recommend that the total combined increases from both dockets (UE 207 and UE 210) be considered in determining the price cap percentage limit.

II. LOSS FACTORS

Q. PLEASE EXPLAIN THE RELEVANCE OF LOSS FACTORS.

A. Losses are the difference between the power which must be generated and the power which is delivered to the ultimate consumer. A utility system, such as PacifiCorp's, has several different types of power lines and substations at various voltages. Larger customers receive service at primary or transmission voltage levels generally in excess of 11,000 volts. Below the primary distribution lines are the distribution line transformers and secondary lines which provide power to the vast majority of PacifiCorp's customers at voltages ranging from 120-480 volts. Due to the nature of the system, losses occur throughout the transmission and distribution process. Therefore, customers who are served at higher delivery voltages generally have lower losses than customers served at a lower voltage. In addition, losses are not a constant value, but vary based on several factors and are dominated by the load level (or electrical current) at a particular time. Consequently, in performing cost analysis, usually two sets of loss factors are used. There are "energy loss factors" to reflect the average loss or load level of the facilities and "peak demand loss factors" to reflect the higher losses that occur on facilities under heavier loadings.

Q. DOES PACIFICORP'S MCA USE BOTH ENERGY AND DEMAND LOSS FACTORS?

A. No. PacifiCorp's MCA uses the same energy based loss factors applied to metered levels to approximate loads at the generator for both energy and demand values. See UE 210, Exhibit PPL/907, Tab 2.3, line 11. However, PacifiCorp loss studies estimate both peak demand and energy loss values at various points on its system. See Exhibit ICNU/202. The demand loss factors from these studies should be used within the MCA for all peak demand factors (for example: system, feeder, and transformer—lines 5, 6 and 7 of Tab 2.3). The following table indicates the demand and energy loss factors from a PacifiCorp loss study done in October 2008. While it is our understanding that these values will be revised slightly, it shows that the information is readily available and can be used to improve or refine the MCA results:

Voltage Level	Energy	Demand
Secondary	1.09396	1.11114
Primary	1.05949	1.08095
Transmission	1.03605	1.04975

Q. SHOULD THESE FACTORS BE APPLIED TO EVERY CLASS BASED ON SIMPLY DELIVERY VOLTAGE?

A. No. While it is generally recognized that loss factors should be established for each delivery voltage category, a further refinement to this approach is to derive the losses based on the specific facilities used by the customers. On the surface, PacifiCorp's MCA gives the impression it is attempting to use this method as certain subclasses are created for either secondary or primary customers at selected break points. For example, Schedule 48 customers are segregated based on demands being less than or greater than 4 MW. PPL/907, Tab 2.3. This differentiation makes sense because a larger customer is likely to be served from a dedicated transformer, while smaller users may receive service from secondary or primary lines. However, within PacifiCorp's MCA, the exact same loss factor is used for each subclass which is not appropriate. PacifiCorp's loss study differentiates losses occurring over each type of facility: service drop, secondary lines, line transformer, primary lines, distribution substations, and transmission system. This information should be used to estimate the loss factor for each subclasses based upon the facilities typically used to serve each subclass. To illustrate, a very large Schedule 48 primary or secondary customer should have a loss factor that simply reflects the transmission system losses coupled with a single transformation.

In fact, many years ago in a Washington proceeding (Washington Utilities and Transportation Commission Docket No. U-83-33), PacifiCorp presented evidence indicating the losses for large secondary customers served on Schedule 48 were lower than the average secondary loss value due to the specific transformers used to serve these customers, coupled with the fact that the customers are required to provide their own services. Rebuttal Testimony of Mr. Sirvaitis, Exhibit T-74, page 6, lines 6-26. In the instant proceeding, PacifiCorp was unable (or unwilling) to provide Schedule 48 customer specific delivery facility information. Exhibit ICNU/203, Schoenbeck/1. Consequently, based upon customer specific billing data I have estimated peak demand and energy loss factors for Schedule 48 primary and secondary customers. In performing this analysis, I used the loss factor by facility from the PacifiCorp loss study, coupled with an assumption that any customer with a demand greater than 2,000 kW was served from a dedicated customer substation. For all customers below this threshold, I used the system average loss factors for either primary or secondary deliveries. The use of the average loss factors for these smaller customers in my view is a very conservative assumption. For example, under my approach the average line transformer loss value for secondary customers is 2.4%. PacifiCorp's Washington analysis indicated a value of about 1%. The following table shows the loss factors by component and a comparison of the PacifiCorp loss factors along with the ICNU factors:

Loss Factors

Component	Energy	Demand
Service Drop	1.00665	1.00729
Secondary	1.00148	1.00178
Line Transformer	1.02420	1.01868
Primary	1.01726	1.02507
Distribution Substation	1.00527	1.00453
Transmission System	1.03605	1.04975
PacifiCorp:		
Primary:	1.05949	1.08095
Secondary:	1.09396	1.11114
ICNU Proposal:		
Primary Customer Substation:	1.04151	1.05451
Primary Conductor Service:	1.05949	1.08095
Secondary Customer Substation:	1.06112	1.06937
Secondary Conductor Service:	1.09396	1.11114
ICNU Average Loss Factors:		
Schedule 48 Secondary	1.08343	1.09902
Schedule 48 Primary	1.04345	1.05801

III. PEAK DEMAND DEVELOPMENT

Q. HOW HAS PACIFICORP CALCULATED THE PEAK DEMANDS USED IN THE MCA?

A. PacifiCorp's MCA employs three demand (or peak) values for specific cost assignments: 1) system demands (for generation and transmission marginal costs); 2) distribution substation and feeder demands; and 3) distribution line transformer demands. For each major class, PacifiCorp derives an average customer peak value based on the average customers' peak usage for all 12 months of a year ("12CP"). An average customer load factor is then derived from the average peak value and the associated average customer energy. This load factor is then used as an input to the MCA (PPL/907, tab 17.4a) and applied to the test period energy usage to derive the peak demand value within the MCA (See PPL/907, Tab 2-3).

Q. IS THERE A BETTER APPROACH FOR DETERMINING THE PEAK DEMANDS?

A. Yes. PacifiCorp has available load research for each class and state that can directly determine hourly loads for the test period. This includes the use of a peaking model to determine peak demands. See Exhibit ICNU/204, Schoenbeck/2-8. Using this data would be a much more transparent and straightforward approach than the convoluted method employed by PacifiCorp.

Q. HAS PACIFICORP'S LOAD FACTOR APPROACH INTRODUCED POTENTIAL ERRORS IN THE MCA?

A. Probably. As an example, consider the development of the 12CP system demand values. The total 12CP system demand used in the MCA is 2,012 MW (sum of class demands on PPL/907, Tab 2.3, line 5). In PacifiCorp's jurisdictional analysis, however, the Oregon 12CP average value is 2,301 MW. PPL/702, Tab 11, page 11.3. In fact, there is only one month in Exhibit PPL/702 (May) where the demand is less than 2,012 MW. ICNU acknowledges that not all customers are included in the MCA, but it is doubtful that the missing load is almost 300 MW. (If this was in fact the case, then this load should be included in the MCA as it is too significant.)

Q. HAS PACIFICORP USED HOURLY CLASS LOADS IN DEVELOPING DEMAND ALLOCATORS IN OTHER STATES?

A. Yes. PacifiCorp has used such data in the cost-of-service study it submits in Washington. While it is for an "embedded" cost-of-service study, there is no reason not to use the same type of data in Oregon.

Q. HAVE YOU REVIEWED THE OREGON LOAD RESEARCH DATA?

A. Yes. Hourly average customer load data was provided to ICNU in response to a data request for the test period of 2010, a one page example of the load data from PacifiCorp's response to ICNU data request ("DR") 3.2. Exhibit ICNU/205, Schoenbeck/1. Using a constant number of customers for each hour (based on the average customer counts for the test period), I derived class contributions for the 12CP system hours. The follow table shows the resulting major class load levels as compared to PacifiCorp's load factor approach:

PacifiCorp Oregon System Peak Demand Comparison (MWs)

	PacifiCorp 12CP Cost Allocation	**Missing MWs**	**Load Research 12CP Allocator**	**Missing MWs**
Sch 4	862	159	1,021	16%
Sch 23	155	118	273	43%
Sch 28	347	135	482	28%
Sch 30	223	79	303	26%
Sch 48	377	16	393	4%
Total:	1,965	508	2,472	21%

As the necessary data is available, ICNU recommends that PacifiCorp use the hourly load research data for the jurisdictional study and the MCA in order to provide a more transparent road map of the cost responsibility for the state of Oregon and each customer class.

IV. MCA PEAK DEMAND SELECTION

Q. DO YOU AGREE WITH PACIFICORP'S USE OF 12CP PEAK DEMANDS IN THE MCA?

A. No. In performing a MCA, it is critical that there be consistency in the derivation of the per unit marginal cost and the cost causation unit (customers, energy, peak, etc.) to which the cost is applied. To illustrate this "matching" concept, consider PacifiCorp's MCA with regard to distribution substations. PacifiCorp derives a marginal cost of substation investment based upon the incremental capacity (MVa or kVa) and the expected cost of additions for the period of 2008 through 2012. The resulting value is $159/kVa (in 2010 dollars). Using a carrying charge rate of 10.79%, PacifiCorp's annual per unit marginal cost for distribution substation investment is $17.18/kW. PPL/907, Tab 7.1 and 7.2. This marginal demand cost should be applied to the peak demand placed on each distribution substation. By using this measure of demand, there is a proper matching of the marginal cost with the cost causation factor. In contrast, PacifiCorp's MCA uses the feeder peak values. These values are the average of the twelve monthly jurisdictional coincident peaks. Using this average value dramatically understates the marginal capacity costs contained within the MCA for two reasons. First, giving each and every month equal weight ignores the fundamental driver of new substation investment, as distribution substations are sized based on the peak demands placed on the facility. Including the other eleven irrelevant demands in the derivation of the value simply causes an understatement of capacity costs in the MCA. This latter point can be appreciated by reviewing the following table containing the Schedule 4 typical customer data used by PacifiCorp to derive the distribution demand for the largest Oregon class:

Monthly Peaks for Schedule 4 Customer

	Jurisdictional Peak	
	kW	**% of Max**
January	3.763	100%
February	3.444	92%
March	2.950	78%
April	3.353	89%
May	2.639	70%
June	2.020	54%
July	2.103	56%
August	1.751	47%
September	1.719	46%
October	2.278	61%
November	2.701	72%
December	3.139	83%
Average	2.655	71%

Most of the months have demands substantially below the winter peak value that occurs in January. While distribution facilities typically have both a summer and winter capacity rating, the difference is far less than the two times factor between the winter and summer loads indicated in the above table. Thus, the inclusion of these irrelevant low load months substantially understates the cost of serving this class. The same is true with regard to using the jurisdictional coincident peak. Use of such a factor ignores the localized diversity that occurs within a service territory. Absent having the most accurate metric (class loads at each substation peak), a reasonable—and most often used—alternative is class non-coincident demand levels as acknowledged by the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual. The following table compares PacifiCorp’s 12 CP jurisdictional demands with class 1 NCP demands I derived from the hourly load research data. It is readily apparent that use of a 12CP factor for distribution investment understates capacity-related costs by a substantial sum.

Distribution Demand Comparison (MWs)

Major Class	PacifiCorp 12CP Demand	ICNU Class NCP Demand
Sch 4	1,189	2,117
Sch 23	154	387
Sch 28	350	633
Sch 30	227	385
Sch 48	373	436
Sch 41	25	67
Sch 33	22	58
Total:	2,340	4,083

To more accurately assess the cost of serving the various customer classes with regard to distribution substation and feeder costs, I recommend that the class NCPs shown in the above table be used in the MCA instead of PacifiCorp's 12CP jurisdictional values.

Q. DO YOUR SAME ARGUMENTS APPLY TO TRANSFORMER PEAK DEMAND USED IN THE MCA?

A. Yes. PacifiCorp derives the peak line transformer class demands using customer maximum demands coupled with a diversity adjustment to take into account the number of customers receiving service from the transformers. The following table shows the monthly customer maximum demand for Schedule 4 prior to the diversity adjustment:

Customer Maximum Peaks
for Schedule 4

	kW	% of Max
January	9.000	99%
February	8.560	94%
March	8.350	92%
April	8.400	92%
May	6.800	75%
June	6.340	70%
July	5.540	61%
August	5.640	62%
September	6.340	70%
October	7.030	77%
November	8.370	92%
December	9.100	100%
Average	7.456	82%

The above table shows a pattern very similar to the Schedule 4 jurisdictional customer data. The December/January peak loads are much greater than the summer loadings with a ratio of 162% (January & December values divided by July & August values). As shown by Exhibit ICNU/206, Schoenbeck/4, the standard transformer loading guide ratio is only about 132%. Accordingly, the typical transformers installed for this class of customers would be based upon the winter peak load. The other months are not relevant to the sizing of the line transformers for this class.

Q. HAVE YOU DERIVED CUSTOMER MAXIMUM DEMANDS FROM THE HOURLY LOAD RESEARCH DATA FOR EACH MAJOR CLASS?

A. No, the data cannot be used to derive customer maximum demands. To derive reasonable customer maximum demands, I used PacifiCorp's load factor approach but I used only the highest month for each class. In a few instances when these derived customer maximum demands were below the class NCP value from the hourly data used for distribution facilities, I used the class NCP as a conservative transformer demand. The following table presents my recommended line transformer demand values along with the value used by PacifiCorp. It should be noted these values are after the customer diversity adjustment.

Transformer Demand Comparison (MWs)

	PacifiCorp	ICNU
Major Class	12CP Demand	Customer Maximum
Sch 4	2,244	2,781
Sch 23	375	531
Sch 28	446	639
Sch 30	236	360
Sch 48	157	176
Sch 41	53	116
Sch 33	46	100
Total:	3,557	4,703

Q. WHAT 12CP DEMAND DID PACIFICORP USE FOR SYSTEM COSTS?

A. PacifiCorp's 12CP system values were derived from the twelve monthly system peaks. These same demands were used for both generation and transmission marginal cost assignment.

Q. DO YOU AGREE WITH THIS METHOD?

A. No. The following table presents the monthly peaks for PacifiCorp's entire system and for the state of Oregon:

Comparison of System and Oregon Coincident Peaks

Month	System MW	Percent of Sys Peak	Oregon MW	Percent of Or Peak
January	8,578	92%	2,713	100%
February	8,410	90%	2,587	95%
March	7,701	83%	2,351	87%
April	7,378	79%	2,178	80%
May	7,930	85%	1,841	68%
June	8,681	93%	2,078	77%
July	9,305	100%	2,371	87%
August	9,306	100%	2,417	89%
September	8,611	93%	2,191	81%
October	7,395	79%	2,231	82%
November	8,374	90%	2,239	83%
December	8,719	94%	2,411	89%
Average	8,366	90%	2,301	85%

While the system peaks in the summer due to the influence of the summer peaking Utah load, the January and December winter peak loads are still significant due to the influence of the Oregon and Washington winter peaking loads. The Oregon peaks have a sharper load shape with the months of January and February dominating the remaining months. These load characteristics, coupled with the geographical spread between the eastern and western portions of the system, suggests that different peaks be used for transmission and generation marginal costs.

Q. PLEASE EXPLAIN YOUR REFERENCE TO THE EASTERN AND WESTERN PORTIONS OF PACIFICORP'S SERVICE TERRITORY.

A. PacifiCorp's service territory is not contiguous. The eastern portion includes Utah, south eastern Idaho and Wyoming. The western portion includes portions of Oregon, Washington and northern California. Physically, the two parts are isolated by hundreds of miles. The two portions are electrically connected through high voltage transmission lines but most of this transfer capability is over facilities owned by others. Consequently, while PacifiCorp asserts it operates and plans the system on an integrated basis, it must also address the "local" reliability needs of each area as well. The best example of this is the required transmission capability for the western area, including Oregon.

Q. WHY MUST PACIFICORP ADDRESS THE "LOCAL" RELIABILITY NEEDS OF EACH AREA?

A. The major role of a transmission system is to maintain system reliability and stability regardless of disturbances on the utility system, such as a forced outage of a generating unit. Transmission system planning studies model these numerous conditions or contingencies to ensure the system can operate within the required reliability parameters. Within the Pacific Northwest, one such transmission planning entity is ColumbiaGrid, formed to address transmission constraints on a coordinated or "single utility" basis and in an open and transparent manner. While PacifiCorp is not a member of Columbia Grid, the Bonneville Power Administration ("BPA") is. PacifiCorp is a significant customer of BPA with regard to wheeling services for their western loads. Exhibit ICNU/207 is a portion of the ColumbiaGrid 2009 System Assessment. This study shows how the transmission planners use peak load conditions, including winter peak loads, winter extreme peak loads and summer peak loads, to ensure the necessary reliability. However, while the planners look at summer peak loads, it is the winter load levels that dictate the need for transmission investment in this area as the summer peak is still far from the winter peak for this region. As Pacific Northwest winter peak loads are the cost causation factor for incremental system transmission investment for Oregon customers, this same metric should be used in the MCA.

The following table compares PacifiCorp's 12CP system demands with the ICNU recommendation of using W CP for transmission-related demand costs. The ICNU demands were calculated using the hourly load research data for the system peak hours of January and February as a proxy for the Pacific Northwest coincident peak loads.

Transmission Comparison (MWs)

Major Class	PacifiCorp 12CP Demand	ICNU W CP Demand
Sch 4	862	1,549
Sch 23	155	298
Sch 28	347	497
Sch 30	223	297
Sch 48	377	365
Sch 41	25	11
Sch 33	22	9
Total:	2,011	3,026

Q. ARE YOU RECOMMENDING THAT THESE SAME WINTER DEMANDS BE USED IN THE MCA FOR GENERATION CAPACITY COSTS?

A. No. The monthly system values in the above table indicate there is a dual winter and summer system peak. In other words, the January and December winter peaks are sufficiently close to the July and August summer peak. These two seasonal peaks should be recognized in the MCA by using system demands from January, July, August and December. This approach recognizes that generating resources located in each of the respective areas can be used to serve peak loads in the other area if needed or required.

The following table compares PacifiCorp's 12CP system demands with the ICNU recommendation of using a combination of winter W/S CP for generation-related demand costs. The ICNU demands were calculated using the hourly load research data for the system peak hours of January, July, August and December:

Generation Peak Demand
Comparison (MWs)

Major Class	PacifiCorp 12CP Demand	ICNU W/S CP Demand
Sch 4	862	1,106
Sch 23	155	283
Sch 28	347	503
Sch 30	223	298
Sch 48	377	401
Sch 41	25	26
Sch 33	22	22
Total:	2,011	2,639

V. DISTRIBUTION FEEDER COMMITMENT COSTS

Q. HOW HAS PACIFICORP DETERMINED THE MARGINAL COST OF DISTRIBUTION FEEDERS?

A. PacifiCorp uses a hypothetical feeder configuration to assign and derive marginal distribution feeder costs for the major customer classes. Customers are assigned along the feeder on seven different branches or segments. As part of this process, PacifiCorp classifies costs between commitment and demand components for five of the seven segments. The commitment portion is derived based upon the smallest conductor and pole used to simply provide each customer with access to electricity but irrespective of the customers' load requirements. ICNU agrees with much of PacifiCorp's approach and considers it a refinement to the two other commonly used distribution cost classification methods (zero-intercept and minimum size), as it incorporates customer placement and customer density. Irrespective of what it is called—commitment, access, minimum size or zero intercept—proper distribution cost allocation should contain a customer related component. This is because in any distribution element, there are economies of scale such that as the size of the customer increases, the per unit cost of serving that customer decreases. This fundamental cost structure cannot be captured with the use of a single metric such as kilowatts of demand.

Q. WHERE DO YOU HAVE A DISAGREEMENT WITH PACIFICORP'S FEEDER COST ASSIGNMENT?

A. I strongly disagree with the critical assumption that there is no customer-related component for the two trunk segments PacifiCorp classifies as being only demand related. As the following table shows, the overwhelming numbers of customers are connected to these two segments (6 & 7):

PacifiCorp Oregon Distribution Feeder Model
Customer Distribution

	Branches 1 - 5	Branches 6 & 7	Total	Customer Component
Residential	58,119	430,020	488,139	11.9%
GS 0-15 kW (sec) (23)	8,382	56,970	65,352	12.8%
GS >15 kW (sec) (23)	1,215	8,259	9,474	12.8%
GS (pri) (23)	4	30	34	12.8%
GS < 50 kW (sec) (28)	295	4,164	4,459	6.6%
GS 51-100 kW (sec) (28)	231	3,268	3,500	6.6%
GS > 100 kW (sec) (28)	133	1,886	2,020	6.6%
GS (pri) (28)	3	47	50	6.6%
GS 0-300 kW (sec) (30)	16	224	240	6.9%
GS >300 kW (sec) (30)	41	556	597	6.9%
GS (pri) (30)	4	51	55	6.9%
Irrigation	2,313	3,818	6,131	37.7%
USBR / UKRB	843	1,227	2,070	40.7%
Large GS 1 - 4 MW (sec)	4	119	123	3.4%
Large GS 1 - 4 MW (pri)	2	55	57	3.4%
Total:	71,606	510,694	582,300	12.3%
Percent:	12%	88%		

Thus, under PacifiCorp's method, only a very limited number of customers—just 12%—have distribution feeder commitment costs. The remaining 88% of the customers only have distribution feeder demand-related costs. The same logic that PacifiCorp has applied to branches 1-5 should be applied to branches 6 and 7. Irrespective of the customers' load or location on these segments, there are economies of scale in attaching different size customers to the distribution system. This should be recognized by applying PacifiCorp's minimal cost method across all seven branches of the distribution feeder model.

VI. ICNU MCA RESULTS

Q. HAVE YOU PREPARED A MCA INCORPORATING ALL YOUR RECOMMENDATIONS?

A. Yes. The following table shows the difference in the PacifiCorp and ICNU MCAs based upon total functional marginal cost levels. As you can see, the ICNU study contains an additional $230 million. About $200 million of this is related to demand costs while the remaining $30 million is associated with additional distribution related commitment costs.

MCA Comparison
(Dollars in 000's)

Category	PacifiCorp	ICNU	Difference
Generation	$916,236	$961,088	$44,852
Transmission	$202,854	$280,203	$77,349
Distribution	$372,038	$480,357	$108,320
Customer - Billing	$18,233	$18,233	$0
Customer - Metering	$18,842	$18,842	$0
Customer - Other	$7,310	$7,310	$0
Total	$1,535,514	$1,766,034	$230,520

Exhibit ICNU/208 presents the results of the ICNU MCA by major customer class along with the cost-based increases. A cost-based increase comparison between the PacifiCorp and ICNU studies was previously presented at the start of this testimony. The ICNU MCA presented in ICNU/208 should be used to assign cost-based increases to PacifiCorp’s customer classes.

VII. RATE SPREAD

Q. HOW IS PACIFICORP PROPOSING TO SPREAD THE RATE INCREASE?

A. As explained in Exhibit PacifiCorp/1000, the Company is proposing to spread the increase to the base rates of the various customer classes using the unbundled cost results.

PPL/1000, Griffin/2. ICNU supports this concept in this case as being consistent with past Commission rulings. The Company is then proposing to limit the increase to 1.5 times the system average for general service and large general service rate schedules and use a cap of almost 2.0 times for the lighting and irrigation schedules. PPL/1000, Griffin/4.

Q. DO YOU SUPPORT THE CONCEPT OF CAPPING OR LIMITING THE INCREASE TO CERTAIN CLASSES?

A. Yes, this is appropriate when the application of cost-based increases would otherwise result in unacceptably large increases to some customer classes.

Q. DO YOU CONCUR WITH THE COMPANY'S CAPPING PROPOSAL?

A. No, ICNU disagrees with the proposal for two reasons. First, the Company's capping proposal includes (or takes as a given) the proposed Transition Adjustment Mechanism ("TAM") increase from UE 207 in its present base rate calculation. This is indicated by footnote No. 1 on PPL/1002, Griffith/1. The increases from both dockets should be taken into account in determining the appropriate rate spread. Second, ICNU disagrees that the cap should be different for different customer classes. The same cap or limit should be used for all classes.

Q. HOW DO YOU RECOMMEND THE INCREASE BE SPREAD RESULTING FROM THE TWO DOCKETS?

A. As just noted, ICNU recommends that both increases be taken into account in determining the overall cap percentages. To illustrate this recommendation, assume PacifiCorp is granted rate increases of $20 million in UE 207 and $50 million in UE 210. The Company's present base rates excluding the proposed TAM amount are about $947 million. Therefore, the average system increase from the two dockets is 7.4% (20 + 50 /

947). This combined percent should be to determine the class percentage caps. ICNU recommends that a cap of 1.5 the average combined increase be applied to all customer classes using the ICNU MCA cost-based results from the instant docket and the final rate spread proposal from UE 207. Under the ICNU MCA study in this case, a very modest amount of mitigation is required (about $360,000) for two classes—Schedule 23 and the lighting schedules. A class specific mitigation allocation proposal will be presented by ICNU once the overall increases are known with greater certainty.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU/201

QUALIFICATIONS OF DONALD SCHOENBECK

July 24, 2009

QUALIFICATIONS AND BACKGROUND
OF
DONALD W. SCHOENBECK

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Donald W. Schoenbeck, 900 Washington Street, Suite 780, Vancouver, Washington 98660.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a consultant in the field of public utility regulation and I am a member of Regulatory & Cogeneration Services, Inc. (RCS).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have a Bachelor of Science Degree in Electrical Engineering from the University of Kansas and a Master of Science Degree in Engineering Management from the University of Missouri.

From June of 1972 until June of 1980, I was employed by Union Electric Company in the Transmission and Distribution, Rates, and Corporate Planning functions. In the Transmission and Distribution function, I had various areas of responsibility, including load management, budget proposals and special studies. While in the Rates function, I worked on rate design studies, filings and exhibits for several regulatory jurisdictions. In Corporate Planning, I was responsible for the development and maintenance of computer models used to simulate the Company's financial and economic operations.

In June of 1980, I joined the consulting firm of Drazen-Brubaker & Associates, Inc. Since that time, I have participated in the analysis of various utilities for power cost forecasts, avoided cost pricing, contract negotiations for gas and electric services, siting and licensing proceedings, and rate case purposes including revenue requirement determination, class cost-of-service and rate design.

In April 1988, I formed RCS. RCS provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers. We also assist in the negotiation of contracts for utility services for large users. In general, we are engaged in regulatory consulting, rate work, feasibility, economic and cost-of-service studies, design of rates for utility service and contract negotiations.

Q. IN WHICH JURISDICTIONS HAVE YOU TESTIFIED AS AN EXPERT WITNESS REGARDING UTILITY COST AND RATE MATTERS?

A. I have testified as an expert witness in rate proceedings before commissions in the states of Alaska, Arizona, California, Delaware, Idaho, Illinois, Maryland, Montana, Nevada, North Carolina, Ohio, Oregon, Washington, Wisconsin and Wyoming. In addition, I have presented testimony before the Bonneville Power Administration, the National Energy Board of Canada, the Federal Energy Regulatory Commission, publicly-owned utility boards and in court proceedings in the states of Washington, Oregon and California.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU/202

2007 ANALYSIS OF SYSTEM LOSSES
OCTOBER 2008

July 24, 2009

PACIFICORP

Oregon

2007 Analysis of System Losses

October 2008

Prepared by:

Management Applications Consulting, Inc.
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October 22, 2008

Mr. Kenneth Houston, PE
Director, Transmission
PacifiCorp
825 NE Multnomah, Suite 1600
Portland, OR 97232

RE: 2007 LOSS ANALYSES – Oregon

Dear Mr. Houston:

Transmitted herewith are the results of the 2007 Analysis of System Losses for the Oregon operations. These results consist of an Annual analysis which develops cumulative expansion factors (loss factors) for both demand (peak-kW) and energy (average-kWh) losses by discrete voltage levels applicable to metered sales data. The loss calculations were made using a separate transmission loss model which was then incorporated into the Oregon loss model to derive the final results prescribed herein.

On behalf of MAC, we appreciate the opportunity to assist you in performing the loss analysis contained herein. The level of detail, multiple databases, and state jurisdictions coupled with power flow studies and updates are consistent with prior loss studies and reflect reasonable and representative power losses on the PacifiCorp system. Our review of these data and calculated loss results support the proposed loss factors as presented herein for your use in various cost of service, rate studies, and demand analyses.

Should you require any additional information, please let us know at your earliest convenience.

Sincerely,

Paul M. Normand
Principal

PACIFICORP - OREGON

2007 ANALYSIS OF SYSTEM LOSSES

TABLE OF CONTENTS

Oregon 2007 Analysis of System Losses

1.0 EXECUTIVE SUMMARY

This report presents PacifiCorp's 2007 Analysis of System Losses for Oregon's power systems as performed by Management Applications Consulting, Inc. (MAC). The study developed separate demand (kW) and energy (kWh) loss factors for each voltage level of service in the power system. The cumulative loss factor results by voltage level, as presented herein, can be used to adjust metered sales data in Oregon for losses in performing cost of service studies, determining voltage discounts, and other analyses which may require a loss adjustment.

The procedures used in the overall loss study were consistent with prior studies and emphasized the use of "in house" resources where possible. To this end, extensive use was made of the Company's peak hour power flow studies and transformer plant investments in the model. Using estimated load data provided a means of calculating reasonable estimates of losses by using a "top-down" and "bottom-up" procedure. In the "top-down" approach, losses from the high voltage system, through and including distribution substations, were calculated along with power flow data, conductor and transformer loss estimates, and metered sales.

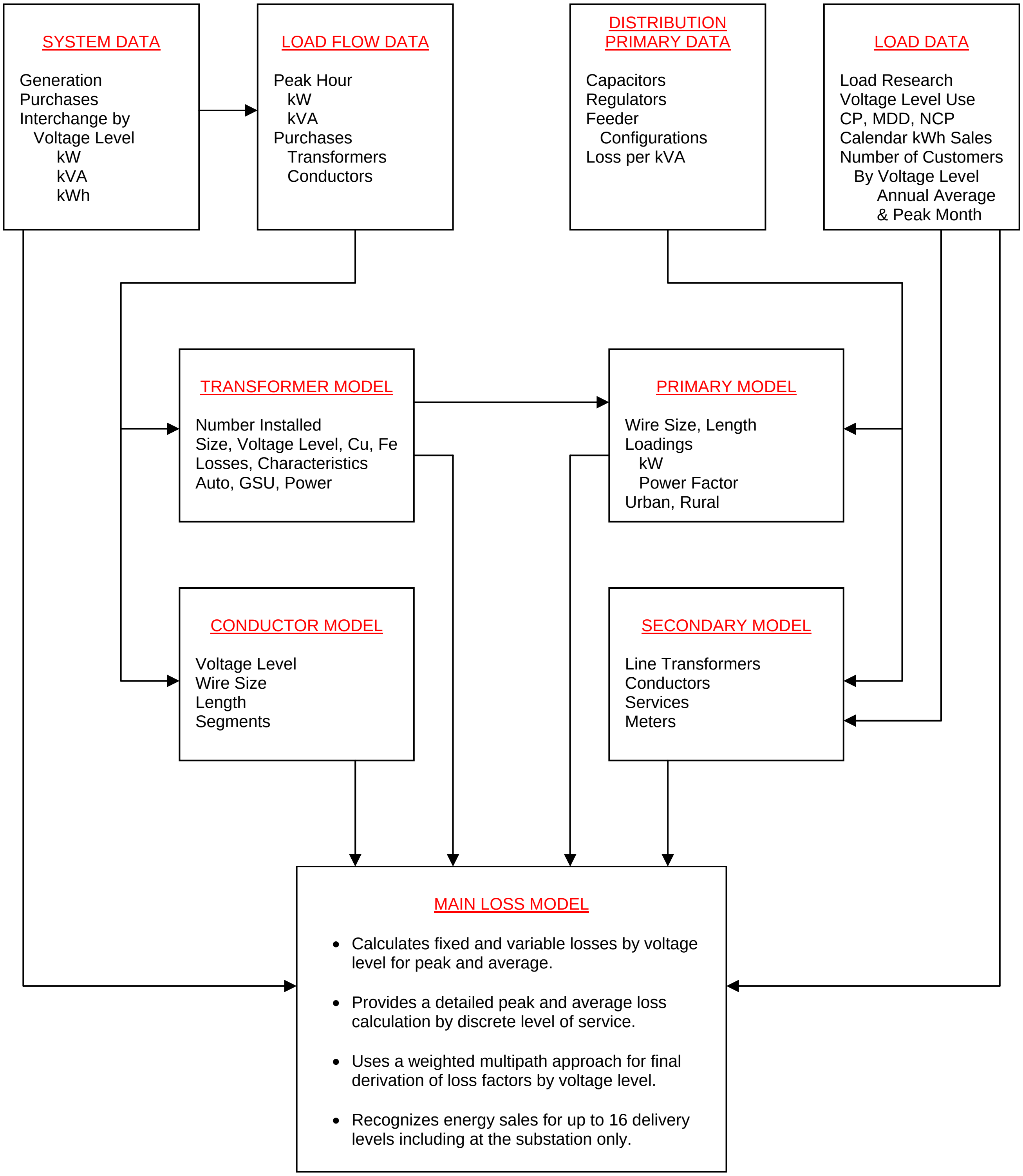
At this point in the analysis, system loads and losses at the input into the distribution substation system are known with reasonable accuracy. However, it is the remaining loads and losses on the distribution substations, primary system, secondary circuits, and services which are generally difficult to estimate. Estimated load data provided the starting point for performing a "bottom-up" approach for calculating the remaining distribution losses. Basically, this "bottom-up" approach develops line loadings by first determining loads and losses at each level beginning at a customer's meter service entrance and then going through secondary lines, line transformers, primary lines and finally distribution substation. These distribution system loads and associated losses are then compared to the initial calculated input into Distribution Substation loadings for reasonableness prior to finalizing the loss factors. An overview of the loss study is shown on Figure 1 on the next page.

Appendix A presents the results of the PacifiCorp system-wide Transmission 2007 Loss Analysis for the integrated PacifiCorp System. Appendix B presents the PacifiCorp Oregon 2007 Loss Analyses.

Table 1, below, provides the final results from Appendix A and B for the calendar year. The distribution system losses are calculated in Appendix B for all voltage levels except transmission which was obtained from Appendix A. These loss expansion factors are applicable only to metered sales at the point of receipt for adjustment to the power system's input level.

These loss factors have shown an improving trend in system utilization and efficiency through investments, operations and load growth. Future studies should encompass an expanded review

MANAGEMENT APPLICATIONS CONSULTING, INC.
ELECTRIC LOSS MODEL OVERVIEW



of the power system by reviewing the detailed unbilled calculations and additional primary circuit analyses.

TABLE 1
Loss Factors at Sales Level
Oregon

Voltage Level of Service	2007	2003	2002	2001
Demand (kW)				
Transmission[1]	1.04975	1.04775	1.05144	1.05697
Primary	1.08095	1.08658	1.09134	1.09755
Secondary	1.11114	1.11606	1.12187	1.12746
Energy (kWh)				
Transmission[1]	1.03605	1.03788	1.04020	1.04543
Primary	1.05949	1.05846	1.06240	1.06908
Secondary	1.09396	1.08421	1.09146	1.09950

Oregon jurisdictional losses for 2007, when measured against total Net System Input (NSI) in this study represent 7.71% as shown on Exhibit 1 of Appendix B. These same losses, when measured against total annual sales output represent 8.36%.

[1]Reference Appendix A for development of Transmission loss factors.

Oregon 2007 Analysis of System Losses

2.0 INTRODUCTION

This report of the 2007 Analysis of System Losses for Oregon provides a summary of results, conceptual background or methodology, description of the analyses, and input information related to the study.

2.1 Conduct of Study

Typically, between five to ten percent of the total kWh requirements of an electric utility is lost or unaccounted for in the delivery of power to customers. Investments must be made in facilities which support the total load which includes losses or unaccounted for load. Revenue requirements associated with load losses are an important concern to utilities and regulators in that customers must equitably share in all of these cost responsibilities. Loss expansion factors are the mechanism by which customers' metered demand and energy data are mathematically adjusted to the generation or input level (point of reference) when performing cost and revenue calculations.

An acceptable accounting of losses can be determined for any given time period using available engineering, system, and customer data along with empirical relationships. This loss analysis for the delivery of demand and energy utilizes such an approach. A microcomputer loss model[2] is utilized as the vehicle to organize the available data, develop the relationships, calculate the losses, and provide an efficient and timely avenue for future updates and sensitivity analyses. Our procedures and calculations are consistent with prior loss studies and rely on numerous databases that include customer statistics and power system modeling results.

Company personnel performed most of the data gathering and data processing efforts and checked for reasonableness. MAC analyzed the Company's various databases and performed calculations to check the reasonableness of results. A review of the preliminary results provided for additions to the database and modifications to certain initial assumptions based on available data. Efforts in determining the data required to perform the loss analysis centered on information which was available from existing studies or reports within the Company.

[2]Copyright by Management Applications Consulting, Inc.

From an overall perspective, our efforts concentrated on five major areas:

1. System information by state jurisdiction concerning peak demand and metered sales data by voltage level,
2. High voltage power system power flow data and associated loss calculations,
3. Distribution system (primary and secondary loss calculations),
4. Derivation of fixed and variable losses by voltage level, and
5. Development of final cumulative expansion factors at each voltage level reconciled to system input.

2.2 Description of Model

The Loss Model is a customized applications model, constructed using the Excel software program. Documentation consists primarily of the model equations at each cell location. A significant advantage of such a model is that the actual formulas and their corresponding computed values at each cell of the model are immediately available to the analyst.

A brief description of the three (3) major categories of effort for the preparation of each loss model is as follows:

- Main sheet which contains calculations for all primary and secondary losses, summaries of all conductor and transformer calculations from other sheets discussed below, output reports and supporting results.

- Transformer sheet which contains data input and loss calculations for each distribution substation and high voltage transformer. Separate iron and copper losses are calculated for each transformer by identified type.

- Conductor sheet containing summary data by major voltage level as to circuit miles, loading assumptions, and kW and kWh loss calculations. Separate loss calculations by voltage segment were made using the Company's power flow models and summarized by voltage level in this model.

Appendix A presents a separate loss study result which derived the loss factors for the Company's system wide transmission only portion of the PacifiCorp power system. These transmission results formed the basis and starting point with which to derive the final Oregon loss factors for each remaining voltage level as presented in Appendix B and summarized on Table 1 of the Executive Summary.

3.0 METHODOLOGY

3.1 Background

The objective of a Loss Study is to provide a reasonable set of energy (average) and demand (peak) loss expansion factors which account for system losses associated with the transmission and delivery of power to each voltage level over a designated period of time. The focus of this study is to identify the difference between total energy inputs and the associated sales with the difference being equitably allocated to all delivery levels. Several key elements are important in establishing the methodology for calculating and reporting the Company's losses. These elements are:

- Selection of voltage level of services,
- Recognition of losses associated with conductors, transformations, and other electrical equipment/components within voltage levels,
- Identification of customers and loads at various voltage levels of service,
- Review of generation or net power supply input at each level for the test period studied, and
- Analysis of kW and kWh sales by voltage levels within the test period.

The three major areas of data gathering and calculations in the loss analysis were as follows:

1. System Information (monthly and annual)
   - MWH generation and MWH sales.
   - Coincident peak estimates and net power supply input from all sources and voltage levels.
   - Customer load data estimates from available load research information, adjusted MWH sales, and number of customers in the customer groupings and voltage levels identified in the model.
   - System default values, such as power factor, loading factors, and load factors by voltage level.

Oregon 2007 Analysis of System Losses

2. High Voltage System

- Conductor information was summarized from a database by the Company which reflects the transmission system by voltage level. Extensive use was made of the Company' s power flow data with the losses calculated and incorporated into the final loss calculations.

- Transformer information was developed in a database to model transformation at each voltage level. Substation power, step-up, and auto transformers were individually identified along with any operating data related to loads and losses.

- Power load flow analysis of peak condition was the primary source of equipment loadings and derivation of load losses in the high voltage loss calculations (greater than 46 kV).

3. Distribution System

- Distribution Substations – data was developed for modeling each substation as to its size and loading. Loss calculations were performed from this data to determine load and no load losses separately for each transformer.

- Primary lines - Line loading and loss characteristics for urban and rural circuits were obtained from distribution feeder analyses. These loss results developed kW loss per MW of load by Primary Voltage level. An average was calculated to derive the primary loss estimate after weighting the proper rural versus urban customer mix.

- Line transformers - Losses in line transformers were based on each customer service group's size, as well as the number of customers per transformer. Accounting and load data provided the foundation with which to model the transformer loadings and calculate load and no load losses.

- Secondary network - Typical secondary networks were estimated for conductor sizes, lengths, loadings, and customer penetration for residential and small general service customers.

- Services - Typical services were estimated for each secondary service class of customers identified in the study with respect to type, length, and loading.

Oregon 2007 Analysis of System Losses

The loss analysis was thus performed by constructing the model in segments and subsequently calculating the composite until the constraints of peak demand and energy were met:

- Information as to the physical characteristics and loading of each transformer and conductor segment was modeled.

- Conductors, transformers, and distribution were grouped by voltage level, and unadjusted losses were calculated.

- The loss factors calculated at each voltage level were determined by "compounding" the per-unit losses. Equivalent sales at the supply point were obtained by dividing sales at a specific level by the compounded loss factor to determine losses by voltage level.

- The resulting demand and energy loss expansion factors were then used to adjust all sales to the generation or input level in order to estimate the difference.

- Reconciliation of kW and kWh sales by voltage level using the reported system kW and kWh was accomplished by adjusting the initial loss factor estimates until the mismatch or difference was eliminated.

3.2 Calculations and Analysis

This section provides a discussion of the input data, assumptions, and calculations performed in the loss analysis. Specific appendices have been included in order to provide documentation of the input data utilized in the model.

3.2.1 Bulk, Transmission and Subtransmission Lines

The transmission and subtransmission line losses were calculated based on a modeling of unique voltage levels identified by the Company's power flow configuration for the entire integrated PacifiCorp Power System. Specific information as to length of line, type of conductor, voltage level, peak load, maximum load, etc., were also provided based on Company records and utilized as data input summaries in the loss model.

MW and MVA line loadings were based on PacifiCorp’ s peak load estimate. Calculations of line losses were performed by the Company’ s power flow model for each line segment separately and combined by voltage levels for reporting purposes as shown in the Discussion of Results (Section 4.0) of this report. The loss calculations consisted of determining a circuit current value based on MVA line loadings and evaluating the I^2R results for each line segment.

After system coincident peak hour losses were identified for each voltage level, a separate calculation was then made to develop annual average energy losses based on a loss factor approach. Load factors were determined for each voltage level based on system and customer load information. An estimate of the Hoebel coefficient (see Appendix C) was then used to calculate energy losses for the entire period being analyzed. The results are presented in Section 4.0 of this report.

3.2.2 Transformers

The transformer loss analysis required several steps in order to properly consider the characteristics associated with various transformer types; such as, step-up, auto transformers, distribution substations, and line transformers. In addition, further efforts were required to identify both iron and copper losses within each of these transformer types in order to obtain reasonable peak (kW) and average energy (kWh) losses. While iron losses were considered essentially constant for each hour, recognition had to be made for the varying degree of copper losses due to hourly equipment loadings.

Standardized test data tables were used to represent no load (fixed) and full load losses for different types and sizes of transformers. This test data was incorporated into the loss model to develop relationships representing copper and iron losses for the transformer loss calculation. These results were then totaled by various groups, as identified and discussed in Section 4.0.

The remaining miscellaneous losses considered in the loss study consisted of several areas which do not lend themselves to any reasonable level of modeling for estimating their respective losses and were therefore lumped together into a single loss factor of 0.10%. The typical range of values for these losses is from 0.10% to 0.25%, and we have assumed the lower value to be conservative at this time. The losses associated with this loss factor include bus bars, unmetered station use, and grounding transformers.

3.2.3 Distribution System

The load data at the substation and customer level, coupled with primary and secondary network information, was sufficient to model the distribution system in adequate detail to calculate losses.

Primary Lines

Primary line loadings take into consideration the available distribution load along with the actual customer loads including losses. Estimates were made by the Company of primary line losses by the different levels of distribution voltage and whether they were urban or rural. These estimates consider substations, feeders per substation, voltage levels, loadings, total circuit miles, wire size, and single- to three-phase investment estimates. All of these factors were considered in calculating the actual demand (kW) and energy (kWh) for the primary system.

Line Transformers

Losses in line transformers were determined based on typical transformer sizes for each secondary customer service group and an estimated or calculated number of customers per transformer. Accounting records and estimates of load data provided the necessary database with which to model the loadings. These calculations also made it possible to determine separate copper and iron losses based on a table of representative losses for various transformer sizes.

Secondary Line Circuits

Calculations of secondary line circuit losses were performed for loads served through these secondary line investments. Estimates of typical conductor sizes, lengths, loadings and customer class penetrations were made to obtain total circuit miles and losses for the secondary network. Customer loads which do not have secondary line requirements were also identified so that a reasonable estimate of losses and circuit miles of the investments could be made.

Service Drops and Meters

Service drops were estimated for each secondary customer reflecting conductor size, length and loadings to obtain demand losses. A separate calculation was also performed using customer maximum demands to obtain kWh losses. Meter loss estimates were also made for each customer and incorporated into the calculations of kW and kWh losses included in the Summary Results.

4.0 DISCUSSION OF RESULTS

A brief description of each Exhibit provided in Appendices A and B as follows:

Exhibit 1 - Summary of Company Data

This exhibit reflects system information used to determine percent losses and a detailed summary of kW and kWh losses by voltage level. The loss factors developed in Exhibit 7 are also summarized by voltage level.

Exhibit 2 - Summary of Conductor Information

A summary of MW and MWH load and no load losses for conductors by voltage levels is presented. The sum of all calculated losses by voltage level is based on input data information provided in Appendix A. Percent losses are based on equipment loadings.

Exhibit 3 - Summary of Transformer Information

This exhibit summarizes transformer losses by various types and voltage levels throughout the system. Load losses reflect the copper portion of transformer losses while iron losses reflect the no load or constant losses. MWH losses are estimated using a calculated loss factor for copper and the test year hours times no load losses.

Exhibit 4 - Summary of Losses Diagram (2 Pages)

This loss diagram represents the inputs and output of power at system peak conditions. Page 1 details information from all points of the power system and what is provided to the distribution system for primary loads. This portion of the summary can be viewed as a "top down" summary into the distributor system.

Page 2 represents a summary of the development of primary line loads and distribution substations based on a "bottom up" approach. Basically, loadings are developed from the customer meter through the Company's physical investments based on load research and other metered information by voltage level to arrive at MW and MVA requirements during peak load conditions by voltage levels.

Exhibit 5 - Summary of Sales and Calculated Losses

Summary of Calculated Losses represents a tabular summary of MW and MWH load and no load losses by discrete areas of delivery within each voltage level. Losses have been identified

Oregon 2007 Analysis of System Losses

and are derived based on summaries obtained from Exhibits 2 and 3 and losses associated with meters, capacitors and regulators.

Exhibit 6 - Development of Loss Factors, Unadjusted

This exhibit calculates demand and energy losses and loss factors by specific voltage levels based on sales level requirements. The actual results reflect loads by level and summary totals of losses at that level, or up to that level, based on the results as shown in Exhibit 5. Finally, the estimated values at generation are developed and compared to actual generation to obtain any difference or mismatch.

Exhibit 7 - Development of Loss Factors, Adjusted

The adjusted loss factors are the results of adjusting Exhibit 6 for any difference. All differences between estimated and actual are prorated to each level based on the ratio of each level's total load plus losses to the system total. These new loss factors reflect an adjustment in losses due only to kW and kWh mismatch.

Exhibit 8 – Adjusted Losses and Loss Factors by Facility

These calculations present an expanded summary detail of Exhibit 7 for each segment of the power system with respect to the flow of power and associated losses from the receipt of energy at the meter to the generation for the Company's power system.

Exhibit 9 – Appendix B Only – Summary of Losses by Delivery Voltage

These calculations present a reformatted summary of the losses presented in Exhibit 8 by power system delivery segment as calculated by voltage level of service based on sales.

Appendix A

Results of 2007 PacifiCorp Transmission System Loss Analysis

PACIFICORP TRANSMISSION 2007 LOSS ANALYSIS

PACIFICORP TRANSMISSION

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK	10,126	MW
ANNUAL ENERGY INPUT	69,950,667	MWH
ANNUAL SALES	65,563,650	MWH
Total System Losses	4,387,017	or 6.27%
TOTAL TRANS LOSSES	2,434,063	3.48%

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	MW		% TOTAL	MWH		% TOTAL
TRANS	345,161,115	393.8		82.05%	2,016,370		82.84%
			3.89%			2.88%	
SUBTRANS	69, 57, 46	86.1		17.95%	417,694		17.16%
			0.85%			0.60%	
TOTAL TRANS LOSSES		479.9		100.00%	2,434,063		100.00%
(percent at input)			4.74%			3.48%	

SUMMARY OF LOSS FACTORS

CUMULATIVE SALES EXPANSION FACTORS

SERVICE	KV	DEMAND d	DEMAND 1/d	ENERGY e	ENERGY 1/e
TRANS	345,161,115 69, 57, 46	1.04975	0.95260	1.03605	0.96520

PACIFICORP TRANSMISSION 2007 LOSS ANALYSIS

SUMMARY OF CONDUCTOR INFORMATION

EXHIBIT 2

DESCRIPTION				CIRCUIT MILES	LOADING % RATING	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
--- BULK -----------	345 KV	OR GREATER									
TIE LINES				0.0	0.00%	0.000	0.000	0.000	0	0	0
BULK TRANS				3,108.0	152.21%	70.940	12.432	83.372	317,553	183,496	501,049
SUBTOT				3,108.0		70.940	12.432	83.372	317,553	183,496	501,049
--- TRANS ---------	115 KV	TO	345.00 KV								
TIE LINES				0	0.00%	0.000	0.000	0.000	0	0	0
TRANS1	161 KV			3,621.0	203.12%	106.590	5.432	112.022	358,552	80,169	438,721
TRANS2	115 KV			3,638.0	247.14%	115.230	3.638	118.868	478,537	53,697	532,234
SUBTOT				7,259.0		221.820	9.070	230.890	837,089	133,866	970,955
--- SUBTRANS ------	34 KV	TO	115 KV								
TIE LINES				0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS1	60 KV			2,978.0	349.63%	29.049	0.000	29.049	120,637	0	120,637
SUBTRANS2	40 KV			2,707.0	148.76%	13.240	0.000	13.240	39,377	0	39,377
SUBTRANS3	34 KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT				5,685.0		42.289	0.000	42.289	160,014	0	160,014
TOTAL				16,052		335.049	21.502	356.551	1,314,656	317,362	1,632,018

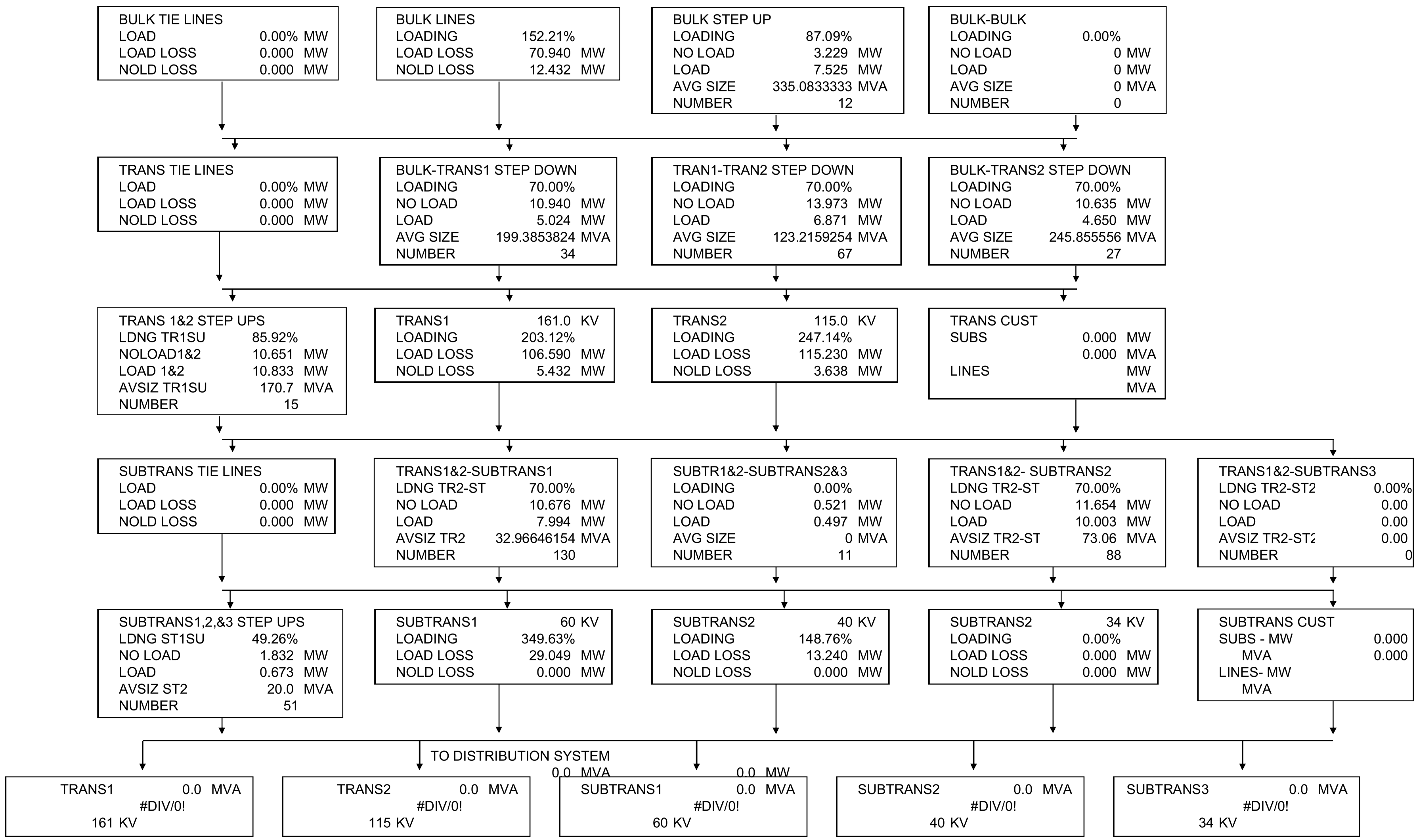
PACIFICORP TRANSMISSION 2007 LOSS ANALYSIS

SUMMARY OF TRANSFORMER INFORMATION

EXHIBIT 3

DESCRIPTION		KV CAPACITY VOLTAGE	MVA	NUMBER TRANSFMR	AVERAGE SIZE	LOADING %	MVA LOAD	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
BULK STEP-UP		345	4,021.0	12	335.1	87.09%	3,502	7.525	3.229	10.755	36,248	27,690	63,939
BULK - BULK			0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS1		161	6,779.1	34	199.4	70.00%	4,745	5.024	10.940	15.964	16,901	95,830	112,731
BULK - TRANS2		115	6,638.1	27	245.9	70.00%	4,647	4.650	10.635	15.285	12,670	93,164	105,834
TRANS1 STEP-UP		161	2,560.0	15	170.7	85.92%	2,200	6.125	4.698	10.823	22,230	39,035	61,265
TRANS1 - TRANS2		115	8,255.5	67	123.2	70.00%	5,779	6.871	13.973	20.844	18,721	122,401	141,122
TRANS1-SUBTRANS1		60	3,171.4	52	61.0	70.00%	2,220	3.663	5.675	9.338	9,982	49,710	59,692
TRANS1-SUBTRANS2		40	450.5	10	45.0	70.00%	315	0.682	0.847	1.529	1,330	7,421	8,751
TRANS1-SUBTRANS3		34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 STEP-UP		115	2,202.8	71	31.0	59.02%	1,300	4.708	5.953	10.661	24,289	46,815	71,104
TRANS2-SUBTRANS1		60	2,571.4	78	33.0	70.00%	1,800	4.330	5.001	9.331	11,799	43,808	55,607
TRANS2-SUBTRANS2		40	5,698.6	78	73.1	70.00%	3,989	9.322	10.807	20.129	18,189	94,669	112,858
TRANS2-SUBTRANS3		34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1 STEP-UP		60	182.3	32	5.7	49.26%	90	0.338	0.727	1.065	2,305	5,304	7,609
SUBTRAN2 STEP-UP		40	380.0	19	20.0	36.33%	138	0.335	1.105	1.439	1,743	5,887	7,630
SUBTRAN3 STEP-UP		34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN2		40	253.4	11	23.0	70.00%	177	0.497	0.521	1.018	969	4,563	5,532
SUBTRAN1-SUBTRAN3		34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-SUBTRAN3		34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
DISTRIBUTION SUBSTATIONS													
TRANS1 -	161	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 -	161	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 -	161	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	60	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	60	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	60	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	40	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	40	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	40	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	34	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	34	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	34	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
			==========	==========	==========	==========		==========	==========	==========	==========	=========	==========
TOTAL			43,164	506				54.071	74.110	128.181	177,377	636,297	813,674

SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK 10126.06046 MW



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PACIFICORP TRANSMISSION 2007 LOSS ANALYSIS

FROM HIGH VOLTAGE SYSTEM

EXHIBIT 4 PAGE 2 of 2

TOTAL 0 MVA 0 MW

TRANS1	TRANS2	SUBTRANS1	SUBTRANS2	SUBTRANS3
0.0 MVA	0.0 MVA	0.0 MVA	0.0 MVA	0.0 MVA
#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
161 KV	115 KV	60 KV	40 KV	34 KV

DISTRIBUTION SYSTEM LOAD

	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3
VOLTAGE	33	12	1	33	12	1	33	12	1	33	12	1	33	12	1
LOAD MVA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
% SYS TOT	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
NOLD LOSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LOAD LOSS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AVG SIZE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NUMBER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DIVERSITY	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
RATIO															

PACIFICORP TRANSMISSION 2007 LOSS ANALYSIS

SUMMARY of SALES and CALCULATED LOSSES

EXHIBIT 5

LOSS # AND LEVEL	MW LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC	MWH LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC
1 BULK XFMMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0	0
2 BULK LINES	4,882.0	15.66	78.47	94.13	1.019659	1.019659	38,104,961	211,187	353,801	564,988	1.0150503	1.0150503
3 TRANS1 XFMR	4,650.5	10.94	5.02	15.96	1.003445	1.023172	24,442,842	95,830	16,901	112,731	1.0046334	1.0197535
4 TRANS1 LINES	8,245.3	10.13	107.92	118.05	1.014525	1.027784	43,507,964	119,204	369,152	488,356	1.0113519	1.0225754
5 TRANS2TR1 SD	5,663.3	13.97	6.87	20.84	1.003694	1.031581	26,789,440	122,401	18,721	141,122	1.0052957	1.0279907
6 TRANS2BLK SD	4,553.7	10.64	4.65	15.29	1.003368	1.023094	21,540,996	93,164	12,670	105,834	1.0049374	1.0200620
7 TRANS2 LINES	11,556.0	9.59	119.94	129.53	1.011336	1.036191	59,198,406	100,512	502,826	603,338	1.0102967	1.0304693
SUB TOTAL TRAN	10,126.1	70.93	322.87	393.80	1.040463	1.040463	69,950,667	742,298	1,274,072	2,016,370	1.0296812	1.0296812
8 STR1BLK SD												
9 STR1T1 SD	2175.6	5.67	3.66	9.34	1.004311	1.032214	10,291,268	49,710	9,982	59,692	1.0058341	1.0285413
10 SRT1T2 SD	1,764.0	5.00	4.33	9.33	1.005318	1.041702	8,344,281	43,808	11,799	55,607	1.0067088	1.0373825
11 SUBTRANS1 LINES	4,069.5	0.73	29.39	30.11	1.007455	1.043016	19,952,395	5,304	122,943	128,246	1.0064692	1.0370206
12 STR2T1 SD	309.0	0.85	0.68	1.53	1.004972	1.032894	1,218,242	7,421	1,330	8,751	1.0072355	1.0299742
13 STR2T2 SD	3,909.2	10.81	9.32	20.13	1.005176	1.041554	15,410,225	94,669	18,189	112,858	1.0073776	1.0380717
14 STR2S1 SD	173.8	0.52	0.50	1.02	1.005889	1.049158	685,247	4,563	969	5,532	1.0081390	1.0454609
15 SUBTRANS2 LINES	4,535.4	1.10	13.57	14.68	1.003247	1.043320	18,095,489	5,887	41,119	47,006	1.0026044	1.0388602
16 STR3T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
17 STR3T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
18 STR3S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
19 STR3S2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
20 SUBTRANS3 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
21 SUBTRANS LOSS FAC					0.000000						0.0000000	
22 TRANSMSN LOSS FAC	10,126.1	95.61	384.32	479.93	1.049754	1.049754	69,950,667	953,660	1,480,404	2,434,063	1.0360513	1.0360513
DISTRIBUTION SUBST												
TRANS1	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
TRANS2	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
SUBTR1	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
SUBTR2	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
SUBTR3	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
WEIGHTED AVERAGE	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
PRIMARY INTRCHNGE	0.0				0.000000		0				0.0000000	
Average Dist Sub Losses	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
		==========	==========	==========				==========	==========	==========		
TOTAL SYSTEM		95.61	384.32	479.93				953,660	1,480,404	2,434,063		

PACIFICORP TRANSMISSION 2007 LOSS ANALYSIS

DEVELOPMENT of LOSS FACTORS
SYSTEM WIDE
DEMAND

EXHIBIT 6

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	CALC LOSS TO LEVEL b	SALES MW @ GEN c	CUM SALES EXPANSION FACTORS d	1/d
BULK LINES	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	9,646.1	479.9	10,126.1	1.04975	0.95260
SUBTRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS LINES	0.0	0.0	0.0	0.00000	0.00000
TOTALS	9,646.1	479.9	10,126.1		

DEVELOPMENT of LOSS FACTORS
SYSTEM WIDE
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	CALC LOSS TO LEVEL b	SALES MWH @ GEN c	CUM SALES EXPANSION FACTORS d	1/d
BULK LINES	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0.00000	0.00000
TRANS LINES	67,516,604	2,434,063	69,950,667	1.03605	0.96520
SUBTRANS SUBS	0	0	0	0.00000	0.00000
SUBTRANS LINES	0	0	0	0.00000	0.00000
TOTALS	67,516,604	2,434,063	69,950,667		

PACIFICORP TRANSMISSION 2007 LOSS ANALYSIS

Adjusted Losses and Loss Factors by Facitliy EXHIBIT 8

Losses by Segment

	MW	MWH
46-57 kV Line Losses (ST2)	14.67940	47,006
T1 - ST2 Transformation Losses	1.52889	8,751
T2 - ST2 Transformation Losses	20.12853	112,858
ST1 - ST2 Transformation Losses	1.01764	5,532
69 kV Line Losses (ST1)	30.11445	128,246
T1 - ST1 Transformation Losses	9.33818	59,692
T2 - ST1 Transformation Losses	9.33132	55,607
115-138 kV Line Losses (T2)	129.52922	603,338
B - T2 Transformation Losses	15.28528	105,834
T1 - T2 Transformation Losses	20.84362	141,122
161-230 kV Line Losses (T1)	118.04657	488,356
B - T1 Transformation Losses	15.96387	112,731
345-500 kV Line Losses (B)	94.12659	564,988
Total	479.93356	2,434,063

Loss Factors by Segment

	MW	MWH
Deliveries from Sub Transmission 2 Lines	4535.41	18,095,489
ST2 Line Losses	14.68	47,006
T1 - ST2 Transformation Losses	1.53	8,751
T2 - ST2 Transformation Losses	20.13	112,858
ST1 - ST2 Transformation Losses	1.02	5,532
Input to ST2 System	4572.77	18,269,637
ST2 Loss Factor	**1.00824**	**1.00962**
Deliveries from Sub Transmission 1 Lines	4069.53	19,952,395
ST1 Line Losses	30.11	128,246
T1 - ST1 Transformation Losses	9.34	59,692
T2 - ST1 Transformation Losses	9.33	55,607
Input to ST1 System	4118.31	20,195,941
ST1 Loss Factor	**1.01199**	**1.01221**
Deliveries from Transmission 2 Lines	11555.99	59,198,406
T2 Line Losses	129.53	603,338
B - T2 Transformation Losses	15.29	105,834
T1 - T2 Transformation Losses	20.84	141,122
Input to T2 System	11721.65	60,048,700
T2 Loss Factor	**1.01434**	**1.01436**
Deliveries from Transmission 1 Lines	8245.27	43,507,964
T1 Line Losses	118.05	488,356
B - T1 Transformation Losses	15.96	112,731
Input to T1 System	8379.28	44,109,051
T1 Loss Factor	**1.01625**	**1.01382**
Deliveries from Bulk Lines	4882.00	38,104,961
B Line Losses	94.13	564,988
Input to B System	4976.13	38,669,949
B Loss Factor	**1.01928**	**1.01483**
Total Deliveries from Transmission	9646.13	67,516,604
Total Transmission Losses	479.93	2,434,063
Input to Transmission System	10126.06	69,950,667
Transmission Loss Factor	**1.04975**	**1.03605**

Appendix B

Results of PacifiCorp Oregon 2007 Loss Analysis

PACIFICORP OREGON 2007 LOSS ANALYSIS

PACIFICORP OREGON

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK		2,598	MW
GENERATION & PURCHASES-INPUT		15,300,810	MWH
ANNUAL SALES	-OUTPUT	14,120,569	MWH
SYSTEM LOSSES	INPUT	1,180,240	or 7.71%
	OUTPUT		or 8.36%
SYSTEM LOAD FACTOR		67.2%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	MW		% TOTAL	MWH		% TOTAL
TRANS	345,161,115	123.1		51.79%	532,420		45.11%
			4.74%			3.48%	
PRIMARY	69,34,12,1	63.2		26.60%	289,268		24.51%
			2.43%			1.89%	
SECONDARY		51.4		21.62%	358,552		30.38%
			1.98%			2.34%	
TOTAL		237.8		100.00%	1,180,240		100.00%
			9.15%			7.71%	

SUMMARY OF LOSS FACTORS

		CUMMULATIVE SALES EXPANSION FACTORS			
SERVICE	KV	DEMAND		ENERGY	
		d	1/d	e	1/e
TRANS	345,161,115	1.04975	0.95260	1.03605	0.96520
PRIM SUBS	69,46,35	0.00000	0.00000	0.00000	0.00000
PRIMARY	69,34,12,1	1.08095	0.92511	1.05949	0.94385
SECONDARY		1.11114	0.89998	1.09396	0.91411

PACIFICORP OREGON 2007 LOSS ANALYSIS

SUMMARY OF CONDUCTOR INFORMATION

EXHIBIT 2

DESCRIPTION			CIRCUIT MILES	LOADING % RATING	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
--- BULK -----------	345 KV	OR GREATER								
TIE LINES			0.0	0.00%	0.000	0.000	0.000	0	0	0
BULK TRANS			0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT			0.0		0.000	0.000	0.000	0	0	0
--- TRANS ---------	115 KV	TO	345.00	KV						
TIE LINES			0	0.00%	0.000	0.000	0.000	0	0	0
TRANS1	161 KV		0.0	0.00%	0.000	0.000	0.000	0	0	0
TRANS2	115 KV		0.0	0.00%	0.000	0.000	0.000	0	1	1
SUBTOT			0.0		0.000	0.000	0.000	0	1	1
--- SUBTRANS ------	35 KV	TO	115	KV						
TIE LINES			0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS1	69 KV		0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS2	46 KV		0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS3	35 KV		0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT			0.0		0.000	0.000	0.000	0	0	0
PRIMARY LINES			18,455		50.255	5.375	55.630	174,942	49,123	224,065
SECONDARY LINES			5,782		3.460	0.000	3.460	16,638	0	16,638
SERVICES			12,570		12.480	1.598	14.079	60,433	14,000	74,433
TOTAL			36,807		66.196	6.973	73.169	252,012	63,124	315,137

PACIFICORP OREGON 2007 LOSS ANALYSIS

SUMMARY OF TRANSFORMER INFORMATION

EXHIBIT 3

DESCRIPTION		KV CAPACITY VOLTAGE	MVA	NUMBER TRANSFMR	AVERAGE SIZE	LOADING %	MVA LOAD	--------- MW LOSSES -------- LOAD	NO LOAD	TOTAL	------- MWH LOSSES ------ LOAD	NO LOAD	TOTAL
BULK STEP-UP		345	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - BULK			0.0	0	0.0	0.00%	0	0	0.000	0.000	0	0	0
BULK - TRANS1		161	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS2		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 STEP-UP		161	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 - TRANS2		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS2		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 STEP-UP		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS2		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1 STEP-UP		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2 STEP-UP		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3 STEP-UP		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN2		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
							DISTRIBUTION SUBSTATIONS						
TRANS1 -	161	34	70.0	3	23.3	42.00%	29	0.047	0.079	0.126	194	692	886
TRANS1 -	161	12	85.0	3	28.3	51.10%	43	0.089	0.099	0.187	367	865	1,232
TRANS1 -	161	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	865	865
TRANS2 -	115	34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	12	2,362.2	116	20.4	51.10%	1,207	2.429	2.777	5.206	10,077	24,328	34,405
TRANS2 -	115	1	7.7	2	3.8	51.10%	4	0.011	0.015	0.026	48	129	177
SUBTRAN1-	69	34	4.7	1	4.7	42.00%	2	0.006	0.010	0.016	23	92	115
SUBTRAN1-	69	12	1,750.1	186	9.4	51.10%	894	2.098	2.464	4.562	8,705	21,587	30,291
SUBTRAN1-	69	1	10.9	4	2.7	51.10%	6	0.016	0.020	0.035	65	173	239
SUBTRAN2-	46	34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	46	12	36.8	2	18.4	51.10%	19	0.039	0.045	0.084	161	396	556
SUBTRAN2-	46	1	47.2	5	9.4	51.10%	24	0.057	0.069	0.127	238	608	846
SUBTRAN3-	35	34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
PRIMARY - PRIMARY			115.0	39	2.9	51.10%	59	0.179	0.229	0.408	744	2,004	2,748
LINE TRANSFRMR			7,815.8	201,430	38.8	26.36%	2,060	6.911	29.523	36.434	14,287	258,619	272,906
			===========	===========	===========	===========		===========	===========	===========	===========	==========	===========
TOTAL			12,305	201,791				11.881	35.330	47.212	34,908	310,358	345,266

SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK 2598.116154 MW

BULK TIE LINES		
LOAD	0.00%	MW
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

BULK LINES		
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

BULK STEP UP		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

BULK-BULK		
LOADING	0.00%	
NO LOAD	0	MW
LOAD	0	MW
AVG SIZE	0	MVA
NUMBER	0	

TRANS TIE LINES		
LOAD	0.00%	MW
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

BULK-TRANS1 STEP DOWN		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

TRAN1-TRAN2 STEP DOWN		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

BULK-TRANS2 STEP DOWN		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

TRANS 1&2 STEP UPS		
LDNG TR1SU	0.00%	
NOLOAD1&2	0.000	MW
LOAD 1&2	0.000	MW
AVSIZ TR1SU	0.0	MVA
NUMBER	0	

TRANS1	161.0	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

TRANS2	115.0	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

TRANS CUST		
SUBS	0.000	MW
	0.000	MVA
LINES		MW
		MVA

SUBTRANS TIE LINES		
LOAD	0.00%	MW
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

TRANS1&2-SUBTRANS1		
LDNG TR2-ST	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVSIZ TR2	0	MVA
NUMBER	0	

SUBTR1&2-SUBTRANS2&3		
LOADING	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVG SIZE	0	MVA
NUMBER	0	

TRANS1&2- SUBTRANS2		
LDNG TR2-ST	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVSIZ TR2-ST	0.00	MVA
NUMBER	0	

TRANS1&2-SUBTRANS3	
LDNG TR2-ST2	0.00%
NO LOAD	0.00
LOAD	0.00
AVSIZ TR2-ST2	0.00
NUMBER	0

SUBTRANS1,2,&3 STEP UPS		
LDNG ST1SU	0.00%	
NO LOAD	0.000	MW
LOAD	0.000	MW
AVSIZ ST2	0.0	MVA
NUMBER	0	

SUBTRANS1	69	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

SUBTRANS2	46	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

SUBTRANS2	35	KV
LOADING	0.00%	
LOAD LOSS	0.000	MW
NOLD LOSS	0.000	MW

SUBTRANS CUST	
SUBS - MW	0.000
MVA	0.000
LINES- MW	
MVA	

TO DISTRIBUTION SYSTEM
141045.7 MVA
138224.8 MW

TRANS1	72.8 MVA	0.05%	161 KV		
TRANS2	140,028.2 MVA	99.28%	115 KV		
SUBTRANS1	901.8 MVA	0.64%	69 KV		
SUBTRANS2	42.9 MVA	0.03%	46 KV		
SUBTRANS3	0.0 MVA	0.00%	35 KV		

ICNU/202
Schoenbeck/29

FROM HIGH VOLTAGE SYSTEM

TOTAL 141,046 MVA 138,225 MW

TRANS1	TRANS2	SUBTRANS1	SUBTRANS2	SUBTRANS3
72.8 MVA	140,028.2 MVA	901.8 MVA	42.9 MVA	0.0 MVA
0.05%	99.28%	0.64%	0.03%	0.00%
161 KV	115 KV	69 KV	46 KV	35 KV

DISTRIBUTION SYSTEM LOAD

	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3
VOLTAGE	34	12	1	34	12	1	34	12	1	34	12	1	34	12	1
LOAD MVA	29	43	0	0	140,024	4	2	894	6	0	19	24	0	0	0
% SYS TOT	0.02%	0.03%	0.00%	0.00%	99.28%	0.00%	0.00%	0.63%	0.00%	0.00%	0.01%	0.02%	0.00%	0.00%	0.00%
NOLD LOSS	0.079	0.099	0.000	0.000	2.777	0.015	0.010	2.464	0.020	0.000	0.045	0.069	0.000	0.000	0.000
LOAD LOSS	0.047	0.089	0.000	0.000	2.429	0.011	0.006	2.098	0.016	0.000	0.039	0.057	0.000	0.000	0.000
AVG SIZE	23.3	28.3	0.0	0.0	20.4	3.8	4.7	9.4	2.7	0.0	18.4	9.4	0.0	0.0	0.0
NUMBER	3	3	0	0	116	2	1	186	4	0	2	5	0	0	0
DIVERSITY RATIO	1.000	1.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	0.000	1.000	1.000	0.000	0.000	0.000

PRIMARY LINES

LOADING	2186.760	MW
@ SYS PF	2231.388	MVA
LOAD LOSS	50.255	MW
NOLD LOSS	5.375	MW
TOT LOSS	55.630	MW

PRIM/PRIM TRANSF

LOADING	58.783	MW
NOLD LOSS	0.229	MW
LOAD LOSS	0.179	MW
AVG SIZE	2.95	
NUMBER	39	

PRIM CUST LOADS

NO LINES	0.000	MW
CUST SUB	0.000	MVA
NO LINES	0.000	MW
CO. SUB	0.000	MVA
PRIM WITH	236.685	MW
LINES	249.142	MVA

LINE TRANSFORMERS

LOADING	1894.037	MW	MVA	2096.890
NOLD LOSS	29.523	MW		
LOAD LOSS	6.911	MW		
AVG SIZE	38.8	KVA		
NUMBER	201430			

SECONDARY LINES

LOAD	686.243	MW
LOAD LOSS	3.460	MW
NOLD LOSS	0.000	MW
TOT LOSS	3.460	MW

NO SECONDARY LINES

LOAD 1171.360 MW

SERVICES

LOAD	1854.143	MW
LOAD LOSS	12.480	MW
NOLD LOSS	1.598	MW
TOT LOSS	14.079	MW

CUSTOMER SECONDARY LOAD

1840.064 MW

ICNU/202
Schoenbeck/30

PACIFICORP OREGON 2007 LOSS ANALYSIS

SUMMARY of SALES and CALCULATED LOSSES

EXHIBIT 5

LOSS # AND LEVEL	MW LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC	MWH LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC
1 BULK XFMMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0	0
2 BULK LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
3 TRANS1 XFMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
4 TRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
5 TRANS2TR1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
6 TRANS2BLK SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
7 TRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	1	0	1	0.0000000	0.0000000
TOTAL TRAN	0.0	0.00	0.00	0.00	0.000000	0.000000	0	1	0	1	0.0000000	0.0000000
8 STR1BLK SD												
9 STR1T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
10 SRT1T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
11 SUBTRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
12 STR2T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
13 STR2T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
14 STR2S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
15 SUBTRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
16 STR3T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
17 STR3T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
18 STR3S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
19 STR3S2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
20 SUBTRANS3 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
21 SUBTRANS TOTAL	0.0	0.00	0.00	0.00	0.000000		0	0	0	0	0.0000000	
22 TRANSMSN LOSS FAC	2,598.1	24.53	98.61	123.14	1.049754	1.049754	15,300,810	208,601	323,819	532,420	1.0360513	1.0360513
DISTRIBUTION SUBST												
TRANS1	71.4	0.18	0.14	0.31	1.004405	0.000000	420,184	2,422	561	2,983	1.0071509	0.0000000
TRANS2	1,183.0	2.79	2.44	5.23	1.004443	0.000000	6,986,377	24,457	10,125	34,582	1.0049745	0.0000000
SUBTR1	883.8	2.49	2.12	4.61	1.005248	0.000000	5,202,566	21,852	8,793	30,645	1.0059252	0.0000000
SUBTR2	42.0	0.11	0.10	0.21	1.005035	0.000000	247,531	1,004	399	1,402	1.0056980	0.0000000
SUBTR3	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
WEIGHTED AVERAGE	2,180.2	5.6	4.8	10.37	1.004779	1.054771	12,856,658	49,735	19,877	69,612	1.0054440	1.0416916
PRIMARY INTRCHNGE	16.0				1.000000		163,558				1.0000000	
PRIMARY LINES	2,186.8	5.60	50.43	56.04	1.026300	1.082511	13,018,394	49,089	174,942	224,031	1.0175102	1.0599317
LINE TRANSF	1,894.0	29.52	6.91	36.43	1.019613	1.103743	11,383,744	258,619	14,287	272,906	1.0245621	1.0859659
SECONDARY	1,857.6	0.00	3.46	3.46	1.001866	1.105803	11,110,838	0	16,638	16,638	1.0014997	1.0875945
SERVICES	1,854.1	1.60	12.48	14.08	1.007651	1.114264	11,094,201	14,000	60,433	74,433	1.0067545	1.0949407
		==========	==========	==========				==========	==========	==========		
TOTAL SYSTEM		66.84	176.69	243.52				580,046	609,995	1,190,041		

PACIFICORP OREGON 2007 LOSS ANALYSIS

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
DEMAND

EXHIBIT 6

LOSS FACTOR LEVEL	CUSTOMER SALES MW	CALC LOSS TO LEVEL	SALES MW @ GEN	CUM EXPANSION FACTORS	
	a	b	c	d	1/d
BULK LINES	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	283.6	14.1	297.7	1.04975	0.95260
SUBTRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS LINES	0.0	0.0	0.0	0.00000	0.00000
PRIM SUBS	0.0	0.0	0.0	0.00000	0.00000
PRIM LINES	236.7	19.5	256.2	1.08251	0.92378
SECONDARY	1,840.1	210.3	2,050.3	1.11426	0.89745
TOTALS	2,360.3	243.9	2,604.2		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH	CALC LOSS TO LEVEL	SALES MWH @ GEN	CUM EXPANSION FACTORS	
	a	b	c	d	1/d
BULK LINES	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0.00000	0.00000
TRANS LINES	1,690,183	60,933	1,751,116	1.03605	0.96520
SUBTRANS SUBS	0	0	0	0.00000	0.00000
SUBTRANS LINES	0	0	0	0.00000	0.00000
PRIM SUBS	0	0	0	0.00000	0.00000
PRIM LINES	1,410,619	84,541	1,495,160	1.05993	0.94346
SECONDARY	11,019,767	1,046,224	12,065,991	1.09494	0.91329
TOTALS	14,120,569	1,191,698	15,312,268		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	297.70	1,751,116
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	0.00	0
PRIM SUBS	0.00	0
PRIM LINES	256.21	1,495,160
SECONDARY	2,050.32	12,065,991
SUBTOTAL	2,604.23	15,312,268
ACTUAL ENERGY LESS THI	2,598.12	15,300,810
MISMATCH	6.12	11,458
% MISMATCH	0.24%	0.07%

PACIFICORP OREGON 2007 LOSS ANALYSIS

DEVELOPMENT of LOSS FACTORS
ADJUSTED
DEMAND

EXHIBIT 7

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM EXPANSION FACTORS e	f=1/e
BULK LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	283.6	0.0	14.1	297.7	1.04975	0.95260
SUBTRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
PRIM SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
PRIM LINES	236.7	0.0	19.2	255.8	1.08095	0.92511
SECONDARY	1,840.1	0.0	204.5	2,044.6	1.11114	0.89998
TOTALS	2,360.3	0.0	237.8	2,598.1		

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM EXPANSION FACTORS e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	1,690,183	0	60,933	1,751,116	1.03605	0.96520
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
SUBTRANS LINES	0	0	0	0	0.00000	0.00000
PRIM SUBS	0	0	0	0	0.00000	0.00000
PRIM LINES	1,410,619	0	83,911	1,494,530	1.05949	0.94385
SECONDARY	11,019,767	0	1,035,396	12,055,163	1.09396	0.91411
TOTALS	14,120,569	0	1,180,240	15,300,810		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	297.70	1,751,116
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	0.00	0
PRIM SUBS	0.00	0
PRIM LINES	255.84	1,494,530
SECONDARY	2,044.57	12,055,163
	2,598.12	15,300,810
ACTUAL ENERGY LESS THIF	2,598.12	15,300,810
MISMATCH	0.00	0
% MISMATCH	0.00%	0.00%

PACIFICORP OREGON 2007 LOSS ANALYSIS

Adjusted Losses and Loss Factors by Facitliy

EXHIBIT 8

Unadjusted Losses by Segment

	MW	MWH
Service Drop Losses	14.12	74,621
Secondary Losses	3.47	16,680
Line Transformer Losses	36.55	273,594
Primary Line Losses	56.21	224,596
Distribution Substation Losses	10.40	69,788
Transmission System Losses	123.14	532,420
Total	243.89	1,191,698

Mismatch Allocation by Segment

	MW	MWH
Service Drop Losses	0.72	1,297
Secondary Losses	0.18	290
Line Transformer Losses	1.85	4,755
Primary Line Losses	2.85	3,903
Distribution Substation Losses	0.53	1,213
Transmission System Losses	0.00	0
Total	6.12	11,458

Adjusted Losses by Segment

	MW	MWH
Service Drop Losses	13.40657	73,324
Secondary Losses	3.29516	16,390
Line Transformer Losses	34.69457	268,839
Primary Line Losses	53.36292	220,693
Distribution Substation Losses	9.87462	68,575
Transmission System Losses	123.14001	532,420
Total	237.77385	1,180,240

Loss Factors by Segment

Retail Sales from Service Drops	1840.06	11,019,767
Adjusted Service Drop Losses	13.41	73,324
Input to Service Drops	1853.47	11,093,091
Service Drop Loss Factor	**1.00729**	**1.00665**
Output from Secondary	1853.47	11,093,091
Adjusted Secondary Losses	3.30	16,390
Input to Secondary	1856.77	11,109,481
Secondary Loss Factor	**1.00178**	**1.00148**
Output from Line Transformers	1856.77	11,109,481
Adjusted Line Transformer Losses	34.69	268,839
Input to Line Transformers	1891.46	11,378,320
Line Transformer Loss Factor	**1.01869**	**1.02420**
Retail Sales from Primary	236.69	1,410,619
Req. Whls Sales from Primary	0.00	0
Input to Line Transformers	1891.46	11,378,320
Output from Primary Lines	2128.15	12,788,939
Adjusted Primary Line Losses	53.36	220,693
Input to Primary Lines	2181.51	13,009,632
Primary Line Loss Factor	**1.02507**	**1.01726**
Output from Distribution Substations	2181.51	13,009,632
Adjusted Distribution Substation Losses	9.87462	68,575
Input to Distribution Substations	2191.38	13,078,207
Distribution Substation Loss Factor	**1.00453**	**1.00527**
Retail Sales at from Transmission	283.593	1,690,183
Req. Whls Sales from Transmission	0.00	0
Non-Req. Whls Sales from Transmission	0.000	0
Third Party Wheeling Losses	0.000	0
Input to Distribution Substations	2191.38	13,078,207
Output from Transmission	2,474.976	14,768,390
Adjusted Transmission System Losses	123.14001	532,420
Input to Transmission	2,598.116	15,300,810
Transmission System Loss Factor	**1.04975**	**1.03605**

DEMAND MW **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE** **EXHIBIT 9**

	SERVICE LEVEL		SALES MW	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	**SERVICES**								
2	SALES		1,840.1		1,840.1				
3	LOSSES			13.4	13.4				
4	INPUT				1,853.5				
5	**EXPANSION FACTOR**	**1.00729**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			3.3	3.3				
9	INPUT				1,856.8				
10	**EXPANSION FACTOR**	**1.00178**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			34.7	34.7				
14	INPUT				1,891.5				
15	**EXPANSION FACTOR**	**1.01869**							
16	**PRIMARY**								
17	SECONDARY				1,891.5				
18	SALES		236.7			236.7			
19	LOSSES			53.4	47.4	5.9			
20	INPUT								
21	**EXPANSION FACTOR**	**1.02507**							
22	**SUBSTATION**								
23	PRIMARY				1,938.9	242.6			
24	SALES		0.0				0.0		
25	LOSSES			9.9	8.8	1.1	0.0		
26	INPUT				1,947.7	243.7	0.0		
27	**EXPANSION FACTOR**	**1.00453**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				1,947.7	243.7	0.0		
37	SALES		283.6						283.6
38	LOSSES			123.1	96.9	12.1	0.0		14.1
39	INPUT				2,044.6	255.8	0.0		297.7
40	**EXPANSION FACTOR**	**1.04975**							
41	**TOTALS** LOSSES			237.8	204.5	19.2	0.0		14.1
42	% OF TOTAL			100%	86.01%	8.06%	0.00%		5.93%
43	SALES		2,360.3		1,840.1	236.7	0.0		283.6
44	% OF TOTAL		100.00%		77.96%	10.03%	0.00%		12.01%
45	INPUT		2,598.1		2,044.6	255.8	0.0		297.7
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.11114**	**1.08095**	**NA**		**1.04975**

ENERGY MWH **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE** **EXHIBIT 9**

	SERVICE LEVEL		**SALES**	**LOSSES**	**SECONDARY**	**PRIMARY**	**SUBSTATION**	**SUBTRANS**	**TRANSMISSION**
1	**SERVICES**								
2	SALES		11,019,767		11,019,767				
3	LOSSES			73,324	73,324				
4	INPUT				11,093,091				
5	**EXPANSION FACTOR**	**1.00665**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			16,390	16,390				
9	INPUT				11,109,481				
10	**EXPANSION FACTOR**	**1.00148**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			268,839	268,839				
14	INPUT				11,378,320				
15	**EXPANSION FACTOR**	**1.02420**							
16	**PRIMARY**								
17	SECONDARY				11,378,320				
18	SALES		1,410,619.000			1,410,619			
19	LOSSES			220,693	196,350	24,342			
20	INPUT								
21	**EXPANSION FACTOR**	**1.01726**							
22	**SUBSTATION**								
23	PRIMARY				11,574,670	1,434,961			
24	SALES		0				0		
25	LOSSES			68,575	61,011	7,564	0		
26	INPUT				11,635,681	1,442,525	0		
27	**EXPANSION FACTOR**	**1.00527**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				11,635,681	1,442,525	0		
37	SALES		1,690,183						1,690,183
38	LOSSES			532,420	419,482	52,005	0		60,933
39	INPUT				12,055,163	1,494,530	0		1,751,116
40	**EXPANSION FACTOR**	**1.03605**							
41	**TOTALS** LOSSES			1,180,240	1,035,396	83,911	0		60,933
42	% OF TOTAL			100%	87.73%	7.11%	0.00%		5.16%
43	SALES		14,120,569		11,019,767	1,410,619	0		1,690,183
44	% OF TOTAL		100.00%		78.04%	9.99%	0.00%		11.97%
45	INPUT		15,300,810		12,055,163	1,494,530	0		1,751,116
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.09396**	**1.05949**	**NA**		**1.03605**

Appendix C

Discussion of Hoebel Coefficient

COMMENTS ON HOEBEL COEFFICIENTS

The Hoebel constant represents an established industry standard relationship between peak losses and average losses and is used in a loss study to estimate energy losses from peak demand losses. H. F. Hoebel described this relationship in his article, "Cost of Electric Distribution Losses," Electric Light and Power, March 15, 1959. A copy of this article is attached.

Within any loss evaluation study, peak demand losses can readily be calculated given equipment resistance and approximate loading. Energy losses, however, are much more difficult to determine given their time-varying nature. This difficulty can be reduced by the use of an equation which relates peak load losses (demand) to average losses (energy). Once the relationship between peak and average losses is known, average losses can be estimated from the known peak load losses.

Within the electric utility industry, the relationship between peak and average losses is known as the loss factor. For definitional purposes, loss factor is the ratio of the average power loss to the peak load power loss, during a specified period of time. This relationship is expressed mathematically as follows:

(1) F_{LS} . A_{LS}) P_{LS}

where: F_{LS} = Loss Factor
A_{LS} = Average Losses
P_{LS} = Peak Losses

The loss factor provides an estimate of the degree to which the load loss is maintained throughout the period in which the loss is being considered. In other words, loss factor is the ratio of the actual kWh losses incurred to the kWh losses which would have occurred if full load had continued throughout the period under study.

Examining the loss factor expression in light of a similar expression for load factor indicates a high degree of similarity. The mathematical expression for load factor is as follows:

(2) F_{LD} . A_{LD}) P_{LD}

where: F_{LD} = Load Factor
A_{LD} = Average Load
P_{LD} = Peak Load

This load factor result provides an estimate of the degree to which the load loss is maintained throughout the period in which the load is being considered. Because of the similarities in definition, the loss factor is sometimes called the "load factor of losses." While the definitions are similar, a strict equating of the two factors cannot be made. There does exist, however, a relationship between these two factors which is dependent upon the shape of the load duration curve. Since resistive losses vary as the square of the load, it can be shown mathematically that the loss factor can vary between the extreme limits of load factor and load factor squared. The relationship between load factor and loss factor has become an industry standard and is as follows:

$$(3)\ \ F_{LS}\ .\ H*F_{LD}^{2} + (1-H)*F_{LD}$$

where: F_{LS} = Loss Factor
F_{LD} = Load Factor
H = Hoebel Coefficient

As noted in the attached article, the suggested value for H (the Hoebel coefficient) is 0.7. The exact value of H will vary as a function of the shape of the utility's load duration curve. In recent years, values of H have been computed directly for a number of utilities based on EEI load data. It appears on this basis, the suggested value of 0.7 should be considered a lower bound and that values approaching unity may be considered a reasonable upper bound. Based on experience, values of H have ranged from approximately 0.85 to 0.95. The standard default value of 0.9 is generally used.

Inserting the Hoebel coefficient estimate gives the following loss factor relationship using Equation (3):

$$(4)\ \ F_{LS}\ .\ 0.90*F_{LD}^{2} + 0.10*F_{LD}$$

Once the Hoebel constant has been estimated and the load factor and peak losses associated with a piece of equipment have been estimated, one can calculate the average, or energy losses as follows:

$$(5)\ \ A_{LS}\ .\ P_{LS} * [H*F_{LD}^{2} + (1-H)*F_{LD}]$$

where: A_{LS} = Average Losses
P_{LS} = Peak Losses
H = Hoebel Coefficient
F_{LD} = Load Factor

Loss studies use this equation to calculate energy losses at each major voltage level in the analysis.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU/203

PACIFICORP DATA RESPONSE TO
ICNU DATA REQUEST 7.5

July 24, 2009

UE-210/PacifiCorp
June 19, 2009
ICNU 7th Set Data Request 7.5

ICNU Data Request 7.5

With regard to the attachment provided in response to ICNU request 3.7, please explain the delivery facilities used to provide service to each primary and secondary customer along with the delivery voltage level. Examples of the information being sought for each customer would be: 1) Dedicated 69kV/12kV 10 MVA customer substation; 2) Dedicated 12kV distribution feeder; 3) Dedicated primary feeder 12kV/480V 5 MVA customer transformer; 4) 12kV distribution feeder serving multiple customers, metered voltage 12kV; and 5) 12kV distribution feeder serving multiple customers, 12kV/480V 750 kVA dedicated transformer.

Response to ICNU Data Request 7.5

Detailed individual customer specific distribution substation, transformer, and conductor facilities data is not readily available. The billing determinants and delivery voltage level provided in response to ICNU request 3.7 were retrieved from the Company's billing system data warehouse. The billing system data warehouse contains detail on delivery facility specifications only at the level required for billing purposes, i.e., Secondary, Primary, Transmission.

Customer class distribution pole and conductor data is modeled in the Company's distribution feeder model and is based on historic test period billing determinants and customer location data derived from PacifiCorp's outage management system (CADOPS). This CADOPS information is not directly tied to customer names and addresses. Attachment ICNU 7.5 contains a CADOPS listing of Schedule 48T customers by substation. It also contains the feeder model branch assignment according to the distance from the substation.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

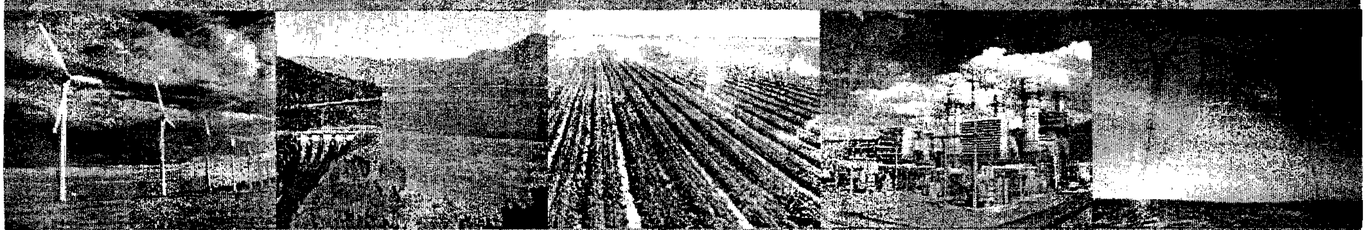
In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU/204

PACIFICORP
2008 IRP

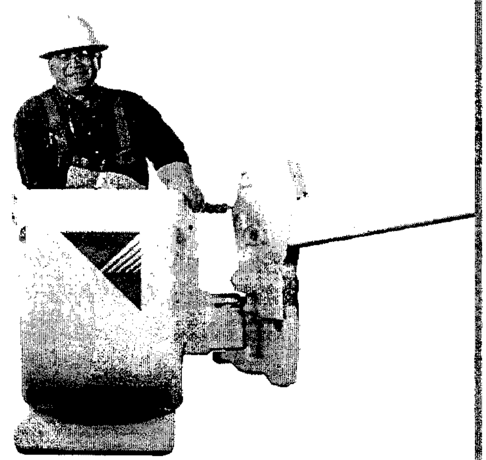
July 24, 2009

Let's turn the answers on



2008 Integrated Resource Plan

Volume I



PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

May 28, 2009

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

5. RESOURCE NEEDS ASSESSMENT

INTRODUCTION

This chapter presents PacifiCorp's assessment of resource need, focusing on the first 10 years of the IRP's 20-year study period, 2009 through 2018. The Company's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are addressed first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity and energy are presented. These balances are comprised of a year-by-year comparison of projected loads against the resource base without new additions. This comparison indicated when PacifiCorp is expected to be either deficit or surplus on both a capacity and energy basis for each year of the planning horizon.

LOAD FORECAST

Methodology Overview

PacifiCorp estimates total load by starting with customer class sales forecasts in each state and then adds line losses to the customer class forecasts to determine the total load required at the generators to meet customer demands. Forecasts are based on statistical and econometric modeling techniques. These models are driven by county and state level forecasts of employment and income that are provided by public agencies or purchased from commercial econometric forecasting services.[24] Appendix E provides additional details on the state-level forecasts.

Evolution and changes in Integrated Resource Planning Load Forecasts

Through the course of the 2008 integrated resource planning cycle, PacifiCorp relied on the November 2008 load forecast for the development of the load and resource balance and portfolio evaluations. Portfolio analysis started as early as June 2008 with preliminary load forecast and continued through December 2008. Under stable economic conditions, the Company would normally prepare one load forecast per year. However, the unstable and volatile economic conditions required the Company to update its load forecasts frequently to attempt to capture price and usage changes between June 2008 and November 2008. Because of the magnitude of the forecast changes and the Company's plan to align IRP filing with the Business Plan, the Company decided that it was prudent to incorporate latest load forecast updates in the IRP. Consequently, PacifiCorp's IRP analysis from November 2008 onward reflects the November 2008 load forecast.

In order to improve sales and load forecasting methods, capabilities, and accuracy, several improvements in the load forecasting approach were identified jointly by the Company and the Company's consultant, ITRON, and the load forecast methodology was changed to incorporate these improvements. Forecast improvements were driven primarily by six major changes in forecast assumptions. First, load research data was used to model the impact of weather on monthly retail sales and peaks by state by class. The Company collects hourly load data from a sample of customers for each class in each state. These data are primarily used for rate design, but they also

[24] PacifiCorp relies on county and state level economic and demographic forecasts provided by Global Insight, in addition to state office of planning and budgeting sources.

provide an opportunity to better understand usage patterns, particularly as they relate to changes in temperature. The greater frequency and data points associated with this hourly data make it better suited to capture load changes driven by changes in temperature than the monthly data used in the Company's prior forecasts.

Second, the time period used to define normal weather was updated from the National Oceanic and Atmospheric Administration's 30-year period of 1971-2000 to a 20-year time period of 1988-2007. The Company identified a trend of increasing summer and winter temperatures in the Company's service territory that was not being captured in the thirty year data. ITRON surveys have identified that many other utilities are also using more recent data for determining normal temperatures. Based on this review and on the recommendation from ITRON, the Company adopted a 20-year rolling average as the basis for determining normal temperatures. This better captures the trend of increasing temperatures observed in both summer and winter.

Third, the historical data period used to develop the monthly retail sales forecasts was updated to cover 1997-2007.

Fourth, monthly peaks were forecasted for each state using a peak model and estimated with historical data from 1990-2007. As an improvement to the forecasting process, the Company developed a model that relates peak loads to the weather that generated the peaks. This model allows the Company to better predict monthly and seasonal peaks. The peak model is discussed in greater detail in the following section.

Fifth, system line losses were updated to reflect actual losses for the 5-years ending December 31, 2007. The Company previously used the results of the most recent system line loss study, which was based on calendar-year 2001 data. The Company had observed that actual losses were higher than those from the previous line loss study. Investigation and discussions with the consultant who prepared the previous line loss study indicated that the previous study only reflected losses associated with retail load. Because there are also system losses associated with wholesale sales, the prior loss value was understated. The use of actual losses is a reasonable basis for capturing total system losses and has been incorporated in this forecast.

Finally, analyses were performed and adjustments made for the impact of current economic conditions. Because the model is estimated over a period of relative prosperity, it is necessary to make an explicit adjustment for the economic downturn, and hence the forecast was revised. In October 2008, the near-term forecast was adjusted downward to reflect the recent recession impacts mirroring load changes experienced in the previous recession (2001-2002). In the November update, the forecast was further adjusted downward in the Industrial sector for Utah (2010 onwards) and Wyoming (2009 onwards) to reflect the additional recession impacts.

In addition to these forecast methodology changes, energy efficiency (Class 2 DSM) was handled differently relative to past IRPs. Rather than treating Class 2 DSM as a decrement to the load forecast, PacifiCorp modeled Class 2 DSM as a resource option to be selected as part of a cost-effective portfolio resource mix using the Company's capacity expansion optimization model. To accomplish this, the load forecast used for IRP portfolio development excluded forecasted load reductions from Class 2 DSM. The capacity expansion model then determines the amount of Class 2 DSM—expressed as supply curves that relate incremental DSM quantities with their costs—given the other resource options and inputs included in the model. The use of Class 2 DSM supply curves, along with the economic screening provided by using the capacity expansion model, determines the cost-effective mix of Class 2 DSM for a given scenario. For retail load forecast reporting, PacifiCorp deducts the Class 2 DSM load reductions reflected in the 2008 IRP preferred portfolio from the original "pre-DSM" load forecast.

Modeling overview

The following section describes the modeling techniques used to develop the load forecast.

The load forecast is developed by forecasting the monthly sales by customer class for each jurisdiction. The residential, commercial, irrigation, public street lighting, and sales to public authority sales forecasts by jurisdiction is developed as a use per customer times the forecasted number of customers.

The residential use-per-customer is forecasted by statistical end-use forecasting techniques. This approach incorporates end use information (saturation forecasts and efficiency forecasts) but is estimated using monthly billing data. Saturation trends are based on analysis of the Company's saturation survey data and efficiency trends are based on EIA forecasts that incorporate market forces as well as changes in appliance and equipment efficiency standards. Major drivers of the statistical end use based residential model are weather-related variables, end-use information such as equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price.

The commercial, irrigation, public street lighting, and sales to public authority use-per-customer forecast is developed using an econometric model. For the commercial class, sales per customer are forecasted using regression analysis techniques with non-manufacturing employment serving as the major economic driver in addition to weather related variables. For other classes, sales per customer are forecasted through regression analysis techniques using time trend variables.

The customer forecasts are generally based on a combination of regression analysis and exponential smoothing techniques using historical data from 1997 to 2007. For the residential class, the customer forecasts are developed using a regression model with Global Insight's forecast of the states' number of households serving as the major driver. For the commercial class, forecasts rely on a regression model with the forecasted residential customer numbers being used as the major driver. For other classes (irrigation, street lighting, and public authority), customer forecasts are developed based on exponential smoothing models.

The industrial sales forecast is developed for each jurisdiction using a model which is dependent on input for the Customer Account Managers (CAMs). The industrial customers are separated into three categories: existing customers that are tracked by the CAMs, new large customers or expansions by existing large customers, and industrial customers that are not tracked by the CAMs. Customers are tracked by the CAMs if (1) they have a peak load of five MW or more or if (2) they have a peak load of one MW or more and have a history of large variations in their monthly usage. The forecast for the first two categories is developed through the data gathered by the CAM assigned to each customer. The account managers have ongoing direct contact with large customers and are in the best position to know about the customer's plans for changes in business processes, which might impact their energy consumption.

The portion of the industrial forecast related to new large customers and expansion by existing large customers is developed based on direct input of the customers, forecasted load factors, and the probability of the project occurrence. Projected loads associated with new customers or expansions of existing large customers are categorized into three groups. Tier 1 customers are those with a signed master electric service agreement ("MESA") or engineering material and procurement agreement ("EMPA"). When a customer signs a MESA or EMPA, this contractually commits the Company to provide services under the terms of agreement. Tier 2 includes customers with a signed engineering services agreement (ESA). This means that customer paid the Company to perform a study that determines what improvements the Company will need to make to serve the requested load. Tier 3 consists of customers who made inquiries but have not signed a formal agreement. Projected loads from customers in each of these tiers are assigned probabilities depending on project-specific information received from the customer.

Smaller industrial customers are more homogeneous and are modeled using regression analysis with trend and economic variables. Manufacturing employment serves as the major economic driver. The total industrial sales forecast is developed by aggregating the forecast for the three industrial customer categories. The segments are forecasted differently within the industrial class because of the diverse makeup of the customers within the class.

After monthly energy by customer class is developed, hourly loads are estimated in two steps. First, PacifiCorp derives monthly and seasonal peak forecasts for each state. The monthly peak model uses historic peak-producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables. These weather variables include the average temperature on the peak day and average daily temperatures for two days prior to the peak day. Second, hourly load forecasts for each state are obtained from the hourly load models using state-specific hourly load data and daily weather variables. Hourly load forecasts are developed using a model that incorporates the 20-year average temperatures, the actual weather pattern for a year, and day-type variables such as weekends and holidays. The model uses HDD (heating degree days) and CDD (cooling degree days) values for each of the twenty years and averages the results using a Rank and Average method instead of averaging by date as in the previous thirty-year process. This helps to incorporate both mild and extreme days in weather patterns, thereby more effectively representing the daily volatility in weather experienced during a typical year. Also, the method preserves the extreme temperatures and maps them to a year to produce a more accurate estimate of daily temperatures. The hourly load forecasts are adjusted for line losses and calibrated to monthly and seasonal peaks. After PacifiCorp develops the hourly load forecasts for each state, hourly loads are aggregated to the total Company system level. System coincident peaks are then identified as well as the contribution of each jurisdiction to those monthly system peaks.

The following sections describe the November 2008 energy and coincident peak load forecasts used for IRP portfolio modeling.

Energy Forecast

Table 5.1 shows average annual energy load growth rates for the PacifiCorp system and individual states. Growth rates are shown for the forecast period 2009 through 2018.

Table 5.1 – Forecasted Average Annual Energy Growth Rates for Load

	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009-2018	2.1%	1.2%	0.7%	1.6%	2.5%	3.4%	1.5%	1.5%

The total net control area load forecast used in this IRP reflects PacifiCorp's forecasts of loads growing at an average rate of 2.1% percent annually from fiscal year 2009 to 2018. Table 5.2 shows the forecasted load for each specific year for each state served by PacifiCorp and the average annual growth (AAG) rate over the entire time period.

Table 5.2 – Annual Load Growth forecasted (in Megawatt-hours) 2009 through 2018

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009	**61,558,392**	15,475,197	4,481,972	1,006,036	24,211,643	10,077,831	3,746,722	2,558,992
2010	**62,572,227**	15,488,359	4,490,263	1,036,284	24,766,082	10,422,330	3,784,242	2,584,666
2011	**63,979,543**	15,733,361	4,528,860	1,072,927	25,331,349	10,873,984	3,825,481	2,613,580
2012	**65,860,922**	16,096,835	4,564,434	1,108,124	26,227,765	11,341,534	3,875,330	2,646,900
2013	**67,602,494**	16,395,770	4,586,107	1,119,431	26,990,389	11,738,006	4,024,940	2,747,851
2014	**69,299,539**	16,648,638	4,620,452	1,128,072	27,811,230	12,117,111	4,142,098	2,831,937
2015	**70,735,798**	16,790,823	4,652,542	1,136,689	28,631,507	12,498,120	4,172,873	2,853,245
2016	**72,193,764**	16,979,579	4,692,854	1,148,202	29,355,209	12,926,718	4,211,552	2,879,649
2017	**73,110,441**	17,080,573	4,709,745	1,153,152	29,791,003	13,240,453	4,237,529	2,897,985
2018	**74,348,970**	17,281,372	4,752,289	1,165,356	30,363,899	13,581,557	4,278,351	2,926,146
				Average Annual Growth Rate				
2009-18	**2.1%**	**1.2%**	**0.7%**	**1.6%**	**2.5%**	**3.4%**	**1.5%**	**1.5%**
2018-28	**1.2%**	**1.1%**	**0.9%**	**1.1%**	**1.6%**	**0.6%**	**0.9%**	**0.9%**
2009-28	**1.6%**	**1.2%**	**0.8%**	**1.3%**	**2.0%**	**1.9%**	**1.2%**	**1.2%**

System-Wide Coincident Peak Load Forecast

The system coincident peak load is the maximum load required on the system in any hourly period. Forecasts of the system peak for each month are prepared based on the load forecast produced using the methodologies described above. From these hourly forecasted values, the coincident system peaks and the non-coincident peaks (within each state) during each month are extracted.

In the 1990's the annual system peak usually occurred in the winter. After 2000, the annual system peak has generally occurred in the summer. The system peak has switched to the summer as a result of several factors. First, the increasing demand for summer space conditioning in the residential and commercial classes and a decreasing demand for electric related space conditioning in the winter has contributed to shift from a winter peak to a summer peak. This trend in space conditioning is expected to continue. Second, Utah with a summer peak that is relatively higher than the winter peak has been growing faster than the system. This growth also has contributed to a shift from a winter peak to a summer peaking system.

Total system load factor is expected to be relatively stable over the 2009 to 2018 time period. There are several factors working in opposite directions, leading to this result. First, the relatively high growth in high load factor industrial sales, particularly in Wyoming, tends to push up the system load factor. Second, as discussed above, the shift in space conditioning tends to push down the system load factor. And, third, efficiency standards such as the 2012 federal lighting standards also tend to push down the system load factor.

Table 5.3 – Forecasted Coincidental Peak Load Growth Rates

Average Annual Growth Rate	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009-2018	2.4%	1.6%	1.8%	1.9%	2.6%	3.1%	2.5%	3.0%

PacifiCorp's eastern system peak is expected to continue growing faster than the western system peak, with average annual growth rates of 2.7 percent and 1.6 percent, respectively, over the forecast horizon.

Table 5.4 below shows that for the same time period the total peak is expected to grow by 2.4 percent.

Table 5.4 – Forecasted Coincidental Peak Load in Megawatts

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2009	10,143	2,463	761	167	4,509	1,253	628	362
2010	10,360	2,476	768	174	4,626	1,290	654	372
2011	10,631	2,526	780	181	4,708	1,354	682	401
2012	10,978	2,579	816	187	4,854	1,394	716	431
2013	11,261	2,638	800	190	5,008	1,440	748	437
2014	11,451	2,695	815	189	5,174	1,485	691	402
2015	11,730	2,728	826	191	5,322	1,530	718	414
2016	12,032	2,763	836	194	5,458	1,577	759	446
2017	12,251	2,795	846	199	5,568	1,616	773	454
2018	12,522	2,836	889	197	5,686	1,656	786	473
Average Annual Growth Rate								
2009-2018	2.4%	1.6%	1.8%	1.9%	2.6%	3.1%	2.5%	3.0%
2018-2028	1.4%	1.4%	1.1%	1.2%	1.8%	0.7%	0.9%	0.6%
2009-2028	1.9%	1.5%	1.4%	1.5%	2.2%	1.9%	1.7%	1.8%

One noticeable aspect of the states contribution to the system coincidental peak forecast is that they do not smoothly increase from year to year, and in Idaho, the contribution to system coincident peak decreases in 2014.

Idaho's contribution to the coincident peak is forecasted to decrease in 2014 even though the total system peak increases from year to year. This behavior occurs because state level coincident peaks do not occur at the same time as the system level coincident peak, and because of differences among the states with regard to load growth and customer mix. While each state's peak load is forecast to grow each year when taken on its own, its contribution to the system coincident peak will vary since the hour of system peak does not coincide with the hour of peak load in each state. As the growth patterns of the class and states change over time, the peak will move within the season, month or day, and each state's contribution will move accordingly, sometimes resulting in a reduced contribution to the system coincident peak from year to year in a particular state. This is seen in a few areas in the forecast as well as experienced in history. For example, the Idaho state load is driven in the summer months by the activity in the irrigation class. The planting and irrigating practices usually cause this state to experience the maximum load in late June or early July. This load then quickly decreases week by week. Consequently, there can be as much as 300 MW of load difference between the maximum load and the loads during the last weeks of July.

Jurisdictional Peak Load Forecast

The economies, industry mix, appliance and equipment adoption rates, and weather patterns are different for each jurisdiction that PacifiCorp serves. Because of these differences the jurisdictional hourly loads have different patterns than the system coincident hourly load. In addition, the growth for the jurisdictional peak demands can be different from the growth in the jurisdictional contribution to the system peak demand. Table 5.5 reports the jurisdictional peak demand growth over the forecast horizon.

Table 5.5 – Jurisdictional Peak Load forecast, 2009 through 2018 (Megawatts)

Year	OR	WA	CA	UT	WY	ID	SE-ID
2009	2,781	850	187	4,678	1,343	776	434
2010	2,795	856	197	4,796	1,371	785	448
2011	2,825	863	204	4,875	1,419	795	453
2012	2,854	876	210	5,033	1,473	806	485
2013	2,914	884	212	5,202	1,532	835	491
2014	2,958	897	214	5,360	1,581	858	497
2015	2,989	909	216	5,522	1,631	867	493
2016	3,010	919	218	5,662	1,680	874	511
2017	3,033	931	221	5,775	1,729	881	518
2018	3,059	942	223	5,902	1,776	890	536
Average Annual Growth Rate							
2009-2018	**1.1%**	**1.1%**	**2.0%**	**2.6%**	**3.2%**	**1.5%**	**2.4%**
2018-2028	**1.3%**	**1.4%**	**1.2%**	**1.8%**	**0.7%**	**0.9%**	**0.9%**
2009-2028	**1.2%**	**1.3%**	**1.6%**	**2.2%**	**1.8%**	**1.2%**	**1.6%**

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU/205

EXAMPLE OF PACIFICORP
HOURLY AVERAGE CUSTOMER LOAD DATA

July 24, 2009

Oregon
Avg/Cust
By Hour
Jan 2010 - Dec 2010

Date	Hour	Sch 004 Sec	Sch 023 0-15 KW Sec	Sch 023 GT 15 KW Sec	Sch 023 Primary	Sch 028 0-50 KW Sec	Sch 028 51-100 KW Sec	Sch 028 GT 100 KW Sec	Sch 028 Primary	Sch 030 0-300 KW Sec	Sch 030 GT 300 KW Sec	Sch 030 Primary	Sch 048 1-4 MW Sec	Sch 048 1-4 MW Pri	Sch 048 GT 4 MW Sec	Sch 048 GT 4 MW Pri	Sch 048 Trans
01JAN10	1	1.801	1.439	9.769	4.978	10.119	24.825	59.929	37.666	85.067	225.648	203.081	490.819	677.754	1,058.875	2,747.316	18,895.625
01JAN10	2	1.638	1.456	9.536	4.889	9.786	24.800	58.482	36.928	85.006	220.796	198.998	452.801	653.348	1,046.125	2,709.640	19,053.250
01JAN10	3	1.599	1.473	9.873	5.042	10.107	24.738	57.399	36.483	83.939	219.755	197.952	445.152	626.156	1,052.375	2,632.801	19,176.000
01JAN10	4	1.821	1.555	10.036	5.158	10.036	25.663	58.351	37.208	84.517	222.819	200.618	433.346	619.549	1,044.750	2,600.860	18,964.500
01JAN10	5	1.966	1.616	10.203	5.264	10.298	27.038	58.673	37.867	88.783	230.919	208.102	443.022	641.183	1,047.625	2,582.368	19,476.375
01JAN10	6	2.131	2.036	10.666	5.702	12.619	30.775	68.875	44.244	102.378	258.715	233.619	518.307	678.027	1,079.000	2,745.360	19,105.125
01JAN10	7	2.507	2.122	12.534	6.545	13.250	35.188	82.458	52.024	116.978	309.572	278.655	612.526	761.915	1,122.000	3,015.794	19,170.625
01JAN10	8	2.693	2.098	15.801	7.919	16.000	37.988	83.726	54.117	129.256	345.407	310.709	646.203	797.058	1,169.125	3,118.846	19,011.625
01JAN10	9	2.767	1.572	17.344	8.272	18.202	42.588	85.161	56.765	132.883	346.227	311.979	649.323	798.286	1,180.000	3,158.125	18,938.750
01JAN10	10	2.568	1.675	18.331	8.751	18.190	45.750	85.167	57.814	137.167	347.630	313.844	647.685	815.759	1,200.750	3,183.250	18,385.875
01JAN10	11	2.255	1.708	18.139	8.688	17.726	47.950	84.673	58.220	136.928	350.324	316.068	658.236	828.888	1,187.875	3,209.338	18,431.375
01JAN10	12	2.211	1.662	17.688	8.470	18.036	45.625	83.113	56.805	136.017	339.630	306.944	642.652	832.996	1,194.125	3,171.574	18,571.750
01JAN10	13	2.137	1.410	16.676	7.895	17.310	38.900	80.548	53.252	132.844	336.838	304.091	658.835	828.813	1,193.500	3,216.015	20,459.125
01JAN10	14	1.935	1.374	16.932	7.983	16.702	39.475	79.637	52.899	129.678	331.907	299.444	645.618	813.482	1,184.375	3,183.904	20,685.500
01JAN10	15	1.932	1.171	16.225	7.566	16.167	39.825	78.917	52.573	128.150	334.215	301.136	632.581	796.321	1,175.375	3,184.426	20,998.125
01JAN10	16	2.099	1.192	15.124	7.111	16.024	38.013	77.560	51.323	118.300	318.604	286.449	614.295	788.085	1,154.625	3,144.375	21,955.125
01JAN10	17	2.554	1.347	16.749	7.890	15.714	39.500	75.911	51.001	111.939	300.884	270.553	603.976	787.875	1,148.125	3,091.279	20,901.500
01JAN10	18	2.582	1.673	14.694	7.205	14.774	37.325	75.679	49.973	107.650	296.035	265.793	590.356	754.250	1,137.125	3,044.632	20,171.625
01JAN10	19	2.429	1.872	14.486	7.231	15.369	33.813	70.649	46.645	105.167	289.674	260.055	548.331	749.799	1,134.250	3,009.662	19,773.000
01JAN10	20	2.427	1.475	14.545	7.027	15.952	30.725	68.815	44.911	96.967	277.303	248.354	539.583	741.509	1,096.375	2,984.551	21,029.250
01JAN10	21	2.180	1.552	13.115	6.464	14.619	30.038	67.500	43.800	93.983	266.407	238.728	525.913	722.817	1,097.875	2,966.184	21,829.250
01JAN10	22	2.117	1.517	11.852	5.908	12.571	29.163	65.214	42.033	90.528	247.704	222.472	521.543	698.545	1,078.875	2,860.449	21,781.875
01JAN10	23	2.110	1.308	11.131	5.481	11.714	26.625	60.339	38.790	85.400	233.502	209.728	492.648	694.813	1,062.875	2,810.404	21,929.625
01JAN10	24	1.676	1.375	10.419	5.217	11.155	25.400	60.827	38.487	83.294	218.813	197.058	470.805	678.295	1,052.750	2,760.713	22,952.250
02JAN10	1	1.584	1.376	9.414	4.791	9.750	24.763	58.905	37.101	81.306	208.713	188.260	451.553	655.107	1,038.625	2,751.640	23,018.375
02JAN10	2	1.520	1.318	9.449	4.772	9.524	23.963	55.976	35.454	82.722	207.488	187.460	428.681	643.496	1,033.125	2,697.875	23,294.875
02JAN10	3	1.342	1.383	9.472	4.819	9.417	24.188	53.857	34.542	82.161	204.370	184.752	416.681	623.353	1,027.375	2,650.537	22,434.000
02JAN10	4	1.592	1.295	9.448	4.759	9.750	24.650	53.530	34.617	81.444	204.521	184.763	417.555	604.513	1,035.625	2,570.221	22,791.000
02JAN10	5	1.588	1.420	9.432	4.824	9.417	25.038	52.500	34.206	83.278	207.921	187.912	412.705	620.848	1,037.000	2,568.243	22,895.750
02JAN10	6	1.720	1.399	9.496	4.839	10.440	26.275	54.417	35.707	85.422	215.704	194.790	429.752	631.487	1,052.625	2,579.412	22,976.375
02JAN10	7	1.701	1.333	10.394	5.182	10.560	27.488	63.750	40.382	91.156	237.516	214.021	462.228	654.496	1,076.375	2,639.059	22,815.375
02JAN10	8	2.240	1.396	12.491	6.109	11.024	29.113	68.476	43.171	99.644	248.127	224.291	465.695	668.045	1,091.000	2,634.022	22,794.500
02JAN10	9	2.820	1.199	13.655	6.491	11.905	31.375	66.762	43.330	99.839	244.398	221.192	479.860	657.996	1,082.375	2,580.904	22,472.250
02JAN10	10	2.804	1.073	13.338	6.283	12.083	32.413	63.905	42.412	102.333	250.567	226.771	481.713	655.554	1,079.500	2,528.610	21,885.625
02JAN10	11	2.857	1.354	13.892	6.680	12.333	31.688	65.988	43.172	101.178	254.273	229.697	489.366	655.402	1,101.750	2,579.919	21,518.250
02JAN10	12	2.879	1.361	14.122	6.782	11.821	32.038	66.637	43.475	104.256	251.336	227.725	480.012	646.438	1,087.875	2,582.654	20,762.250
02JAN10	13	2.720	1.112	13.504	6.376	11.488	31.588	65.345	42.667	100.672	249.475	225.587	481.004	641.058	1,094.000	2,578.434	20,634.375
02JAN10	14	2.277	1.008	12.621	5.941	11.119	32.575	64.012	42.309	99.539	243.965	220.781	464.894	630.817	1,093.375	2,567.728	21,845.500
02JAN10	15	2.139	0.928	12.858	5.996	10.857	32.088	61.756	41.064	98.750	245.549	221.983	452.350	650.893	1,088.875	2,537.096	22,235.750
02JAN10	16	2.388	1.059	11.931	5.678	10.821	32.150	62.625	41.473	98.850	241.731	218.795	436.992	656.982	1,088.000	2,512.294	22,664.125
02JAN10	17	2.337	1.178	12.972	6.188	11.179	34.150	63.381	42.557	97.333	239.965	217.069	442.343	670.304	1,074.250	2,538.243	22,725.250
02JAN10	18	2.467	1.683	13.086	6.527	10.238	36.788	64.714	43.838	98.139	241.058	218.115	441.433	672.777	1,092.500	2,513.338	23,007.125
02JAN10	19	2.826	1.658	12.630	6.319	10.440	35.013	63.893	42.919	97.033	237.859	215.252	442.453	665.795	1,087.875	2,517.809	24,071.375
02JAN10	20	2.629	1.346	12.483	6.077	10.643	34.600	62.423	42.156	90.778	233.396	210.501	438.443	671.754	1,075.375	2,495.397	23,914.125
02JAN10	21	2.629	1.463	12.856	6.303	11.500	33.838	60.756	41.327	89.400	227.525	205.352	436.407	655.871	1,071.875	2,501.971	23,313.875
02JAN10	22	2.546	1.584	11.879	5.958	11.488	33.000	57.994	39.790	88.450	219.169	198.185	431.266	625.259	1,057.375	2,451.022	23,186.375
02JAN10	23	1.834	1.561	10.258	5.256	10.536	30.075	57.560	38.418	86.517	208.699	189.085	422.907	623.732	1,046.250	2,454.581	22,834.125
02JAN10	24	1.526	1.340	9.597	4.848	9.917	29.175	56.988	37.728	84.506	193.981	176.407	398.130	616.871	1,038.625	2,452.213	22,578.875
03JAN10	1	1.359	1.304	9.265	4.686	10.048	28.088	56.214	37.043	83.906	187.558	170.919	388.657	600.830	1,030.750	2,413.625	22,620.625
03JAN10	2	1.395	1.411	9.457	4.829	9.786	28.063	53.881	35.917	84.739	184.069	168.124	387.407	613.237	1,023.875	2,383.022	22,873.000
03JAN10	3	1.534	1.324	9.193	4.667	10.500	28.413	52.458	35.538	84.772	187.229	170.782	388.311	601.469	1,030.125	2,387.794	23,043.000
03JAN10	4	1.491	1.411	9.443	4.823	10.310	28.600	52.185	35.435	83.344	188.912	171.965	383.492	593.241	1,026.875	2,359.044	22,970.875
03JAN10	5	1.506	1.354	9.865	4.970	10.607	29.125	51.940	35.561	85.228	189.859	173.062	380.614	596.821	1,032.375	2,402.809	22,909.750
03JAN10	6	1.727	1.345	9.964	5.007	11.905	30.575	54.024	37.267	87.089	196.389	178.843	387.549	598.469	1,048.875	2,421.632	22,791.000
03JAN10	7	1.889	1.370	10.849	5.397	12.083	32.613	62.446	41.814	93.733	208.030	189.682	387.474	625.915	1,074.625	2,447.000	22,899.125
03JAN10	8	2.081	1.557	11.435	5.753	11.774	32.575	63.429	42.183	96.650	216.931	197.622	400.907	657.844	1,077.250	2,463.956	22,739.375
03JAN10	9	2.923	1.124	11.638	5.591	11.833	29.875	60.512	39.972	96.317	215.940	196.737	411.715	656.612	1,062.250	2,440.309	22,305.625

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU/206

RESIDENTIAL ELECTRICAL DEMAND

July 24, 2009

General—Residential Electrical Demand

A. Scope

This guideline provides information regarding residential electrical demand calculations. Covered are customer class, load factor, peak demand, coincidence factor, and energy-to-demand conversion.

B. General

When actual values are not available, residential energy and demand information can be estimated using the following guidelines. These guidelines are to be used throughout the PacifiCorp System.Transformers must be sized to handle the worst case of both winter and summer loads.

C. Customer Group and Load Factor

Residential customers are categorized into four classes according to connected electrical load. The residential classes and electrical loads are defined below:

1. Class I includes LM
2. Class II includes LMRD
3. Class III includes LMRDW
4. Class IV includes LMRDWH/AIR

Where:

L = lights
M = miscellaneous, including small appliances
R = electric range
D = electric dryer
W = electric water heater
H/HP/AC = electric heat / heat pump / air conditioner

Table 1 relates residential customer class to annual load factor, based on past field tests. The annual load factor is defined as the ratio of the average load divided by the peak load over the time period of a year.

Table 1—Annual Load Factor

Load Factor	Single Family Frame House	Multiple Family Unit	Mobile Home
48.1%	Class I	—	—
40.4%	Class II	non-electric heat	—
40.1%	Class III	—	—
29.0%	Class IV	electric heat	electric heat

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D. Demand Usage

Good judgment should be exercised when using the peak demand tables. The following are examples of items which can vary greatly, and may require adjustment of peak demand values from tables:

1. **Type of Construction**

   insulation

2. **Location**

   elevation
   prevailing winds

3. **Unusual Connected Electrical Loads**

   duplicate major appliances
   hot tub
   sauna
   etc.

Table 2—Peak Demand for Single Family Frame Houses (kW)

	Class I			Class II		
Size of House	winter LM	winter LM+HP	summer LM+AC/HP	winter LMRD	winter LMRD+HP	summer LMRD+AC/HP
< 1300 sq. ft.	3	8	5	5	13	8
1300–2000 sq. ft.	5	10	7	7	17	10
2001–3500 sq. ft.	7	13	10	10	20	13
3501–4500 sq. ft.	—	—	—	—	—	—

	Class III			Class IV
Size of House	winter LMRDW	winter LMRDW+HP	summer LMRDW+AC/HP	summer LMRDW+AC/HP
< 1300 sq. ft.	8	13	13	13
1300–2000 sq. ft.	10	17	17	17
2001–3500 sq. ft.	13	20	20	20
3501–4500 sq. ft.	—	—	—	22

Table 3—Peak Demand per Unit for Multiple Family Units (kW)

Size of Apartment	Non-Electric Heat	Electric Heat
< 800 sq. ft.	4	10
800–1000 sq. ft.	5	13
1001–1400 sq. ft.	9	17

Table 4—Peak Demand for Mobile Homes with Electric Heat (kW)

Size of Mobile Home	Peak Demand
Single-Wide	13
Double-Wide	17
Triple-Wide	25

E. Coincidence Factor

The coincidence factor pertains to the total demand, at any one time, of customers served by a single transformer or set of conductors. Since all of the customers generally don't reach peak load at the same moment, the total load on the cables or transformer is generally less than the sum of the individual peak loads. The coincidental peak demand is determined by adding up the individual peak demands and multiplying by a coincidence factor less than or equal to 1. The coincidence factor is related to the number of customers, and is shown in Table 5:

Table 5—Coincidence Factor

Number Of Customers	1	2	3	4	5	6	7	8	9	10	11 or more
CF for Summer Loads	1.0	.90	.86	.82	.78	.76	.74	.72	.71	.70	.70
CF for Winter Loads	1.0	.77	.70	.67	.64	.62	.60	.59	.58	.57	.56

F. Transformer Facility Design and Loading Guidelines—Single Family Residential

Table 6 lists the maximum loads for single-family dwellings. When designing facilities to serve single-family residences, care must be taken to load transformers as close to these values as possible. Each transformer must be sized for all homes/lots it is designed to serve. It is not necessary to reserve transformer capacity for load growth within the homes unless unusual circumstances exist. Table 6 applies to both pole-mounted and pad-mounted transformers.

After determining the load requirements from Table 2 and Table 5, choose the appropriate transformer size listed in Table 6. Select the value for summer if the loads are expected to peak in summer. Select the value for winter if the loads are expected to peak in winter. Check the overall design for appropriate voltage levels and flicker constraints. Consult your engineer if you have questions.

The loading limits shown in Table 6 are based on 130 percent of nameplate for summer loads and 180 percent of nameplate for winter loads.

In areas with conditions requiring more conservative transformer loadings, use Table 7 when designing facilities. Use Table 6 when evaluating whether transformers already in service should be replaced. Table 7 is based on 100 percent of nameplate for summer loads and 150 percent of nameplate for winter loads.

Both tables apply to residential application with kW at .95 power factor.

Table 6 —Standard Transformer Loading Guidelines
130 Percent Summer Loading, 180 Percent Winter Loading

	Ambient Temp.* (°C/°F)	Transformer Size 25 kVA	50 kVA	75 kVA	100 kVA
Winter	0/32	0-48	49-96	97-144	145-193
	10/50	0-46	47-91	92-137	138-182
	20/68	0-42	43-85	86-127	128-170
Summer	20/68	0-37	38-75	76-113	114-151
	30/86	0-35	36-69	70-104	105-139
	40/104	0-31	32-64	65-95	96-128

*Ambient temperature is the mean average temperature during the peak loading season +5 degrees C (or +9 degrees F) as a safety margin.

Table 7 —Conservative Transformer Loading Guidelines
100 Percent Summer Loading, 150 Percent Winter Loading

Transformer Size	25 kVA	50 kVA	75 kVA	100 kVA
Winter	0-37.5	38-75	76-112.5	113-150
Summer	0-25	26-50	51-75	76-100

G. Energy to Demand Conversion

When the actual energy usage (kWH/day) is available, the peak demand in kW can be approximated using the energy-to-demand conversion graph shown in Figure 1.

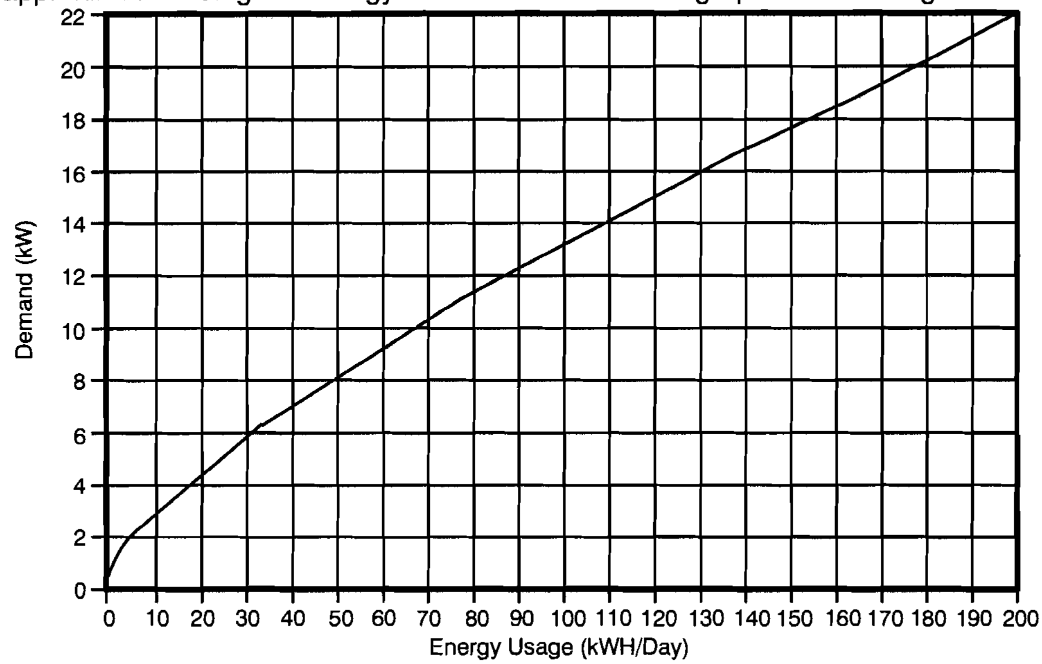

Figure 1—Energy-to-Demand Conversion

H. Example 1

Determine the coincidental peak demand and load factor for the following group of single family frame houses:

Number of Customers	Size of House	Class
1	1000 sq. ft.	II
2	1500 sq. ft.	III
1	2400 sq. ft.	IV

1. **STEP 1**

   Find the individual peak demand values in Table 2, and determine the sum total.

   Peak Demands, from Table 2:

Number of Customers	Class	Individual Demand	Sum of Demands
1	II	5 kW	5 kW
2	III	10 kW	20 kW
1	IV	20 kW	20 kW

   Total Demand = 45kw

2. **STEP 2**

   Using Table 5, determine the group's winter (or summer) Coincidental Peak Demand.

   From Table 5, Coincidence Factor for 4 Customers = 0.67

   Therefore:
   Winter Coincidental Peak Demand = Winter Coincidence Factor * Total Demand
   = 0.67 * 45kW
   = 30.15kW

3. **STEP 3**

   Using Table 1 and Table 2, determine the group's load factor.

   Recall that Load Factor = Average Load / Peak Demand Load.

   Therefore:
   Individual Average Load = Individual Load Factor * Individual Demand

(Example) Average Load

Number of Customers	Class	Individual Demand	Individual Load Factor	Individual Avg. Load	Sum of Avg. Loads
1	II	5 kW	40.4%	2.02 kW	2.02 kW
2	III	10 kW	40.1%	4.01 kW	8.02 kW
1	IV	20 kW	29.0%	5.80 kW	5.80 kW

Total Average Load = 15.84kW

Then:

Group Load Factor = (Total Avg. Load / Winter Coincidental Peak Demand)*100
= (15.84kW / 30.15kW) * 100
= 52.5%

These calculated values (i.e., Coincidental Peak Demand = 30.15kW) would be used in determining the group's transformer and secondary sizes. The service to each individual house would be determined based on the individual peak demand and individual load factor.

I. Example 2

Determine the appropriate size pad-mounted transformer to serve 10 single-family, 2,000 square-foot homes with gas heat and water heating, electric ranges and dryers, and no air conditioning. The mean average temperature in winter is 32° F. The mean average temperature in summer is 87° F.

1. **STEP 1 Determine the Load of Each Home**

   According to Table 2, these homes fall into category II, and each has a load of 7 kW.

2. **STEP 2 Determine the Peak Load for the Transformer**

   The total load for 10 homes is 7 kW × 10 = 70 kW.
   According to Table 5, the winter coincidence factor for 10 homes is .57.
   The coincident peak load on the transformer is therefore 70 kW × .57 = 39.9 kW.

3. **STEP 3 Determine the Appropriate Size of Transformer to Serve the Load**

   From Table 6, choose the winter block and the row for 32° F. The proper size for the transformer is 25 kVA. From the summer block at 87° F (the 86° F block), the proper size for the transformer is 50 kVA. The 50 kVA transformer should be used.

J. Example 3

Size a pad-mounted transformer to serve 10 single-family, 2,000 square-foot homes with gas heat and water heating, electric ranges and dryers, and air conditioning. The mean average temperature in winter is 32° F. The mean average temperature in summer is 97° F.

1. **STEP 1 Determine the Load of Each Home**

   According to Table 2, these homes fall into category II, and each has a load of 10 kW.

2. **STEP 2 Determine the Peak Load for the Transformer**

   The total load for 10 homes is 10 kW × 10 = 100 kW.
   According to Table 5, the summer coincidence factor for 10 homes is .7
   The coincident peak load on the transformer is therefore 100 kW × .7 = 70 kW.

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3. **STEP 3 Determine the Appropriate Size of Transformer to Serve the Load**

   From Table 6, choose the winter block and the row for 32° F. The proper size for the transformer is 50 kVA. From the summer block at 97° F (the 104° F block), the proper size for the transformer is 75 kVA. The 75 kVA transformer should be used.

K. Example 4

Determine the appropriate size pad mounted transformer to serve 10 single-family, 2,000 square-foot homes with gas heat and water heating, electric ranges and dryers, and heat pumps. The mean average temperature in winter is 32° F. The mean average temperature in summer is 87° F.

1. **STEP 1 Determine the Load of Each Home**

   According to Table 2, these homes fall into category II, and each has a load of 17 kW.

2. **STEP 2 Determine the Peak Load for the Transformer**

   The total load for 10 homes is 17 kW × 10 = 170 kW.
   According to Table 5, the winter coincidence factor for 10 homes is .57
   The coincident peak load on the transformer is therefore 170 kW × .57 = 96.9 kW.

3. **STEP 3 Determine the Appropriate Size of Transformer to Serve the Load**

   From Table 6, choose the winter block and the row for 32° F. The proper size for the transformer is 75 kVA. From the summer block at 87° F (the 86° F block), the proper size for the transformer is 75 kVA. The 75 kVA transformer should be used.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

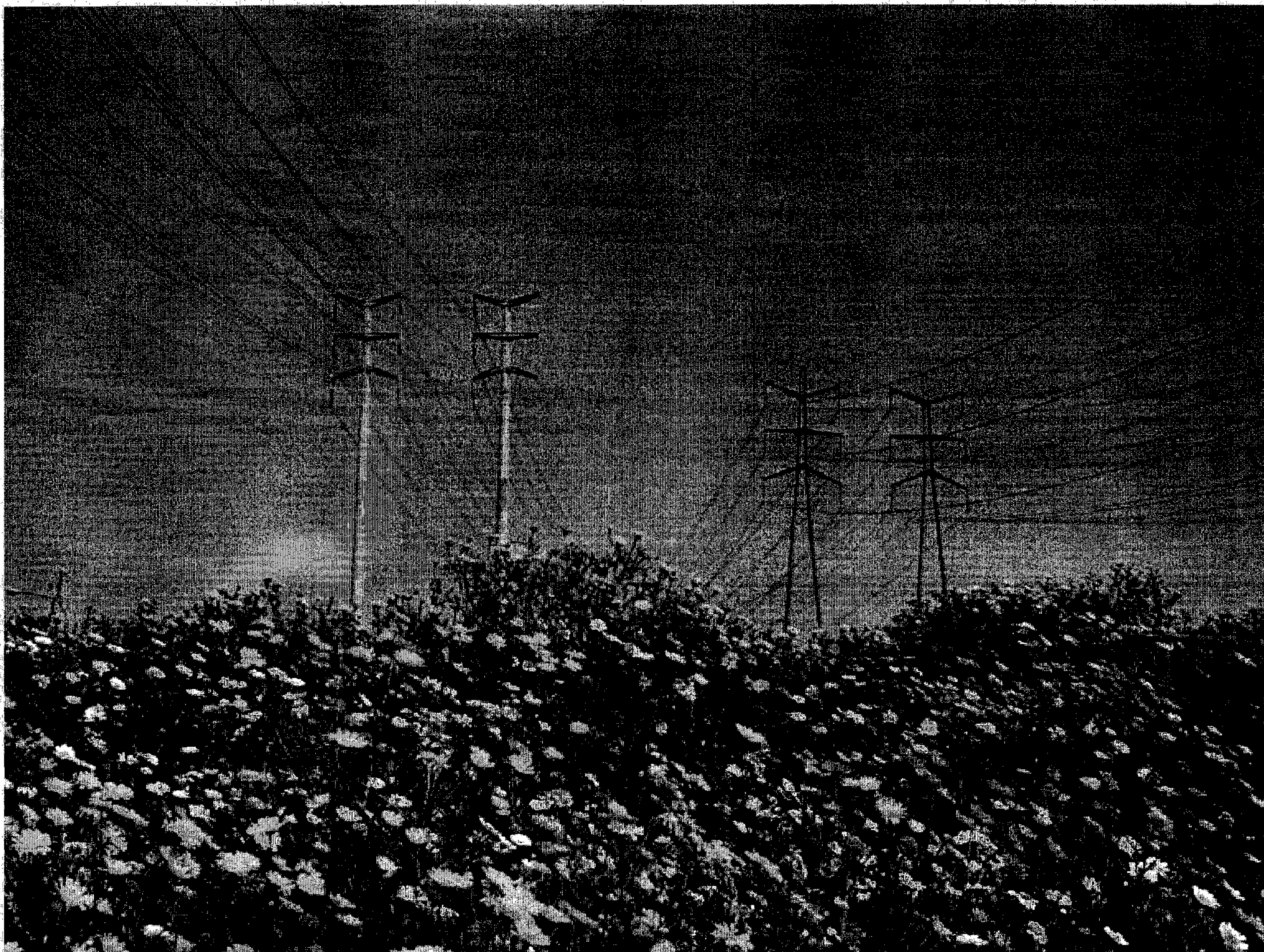
UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU/207

2009 SYSTEM ASSESSMENT
PUBLIC REVIEW DRAFT
(JUNE 30, 2009)

July 24, 2009



Public Review Draft

June 30, 2009

2009 System Assessment

ColumbiaGrid

ICNU/207
Schoenbeck/2

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Copies of this report are available from:
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Spring/Summer 2009

Acknowledgements

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Cowlitz PUD
Grant County PUD
Puget Sound Energy
Seattle City Light
Snohomish County PUD
Tacoma Power

Other Contributors
Northern Tier Transmission Group
Northwest Power and Conservation Council
Northwest Power Pool
PacifiCorp
Portland General Electric

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Disclaimer: The data and analysis contained in this report are not warranteed by ColumbiaGrid or any other party. Any reliance on this data or analysis is done so at the user's own risk.

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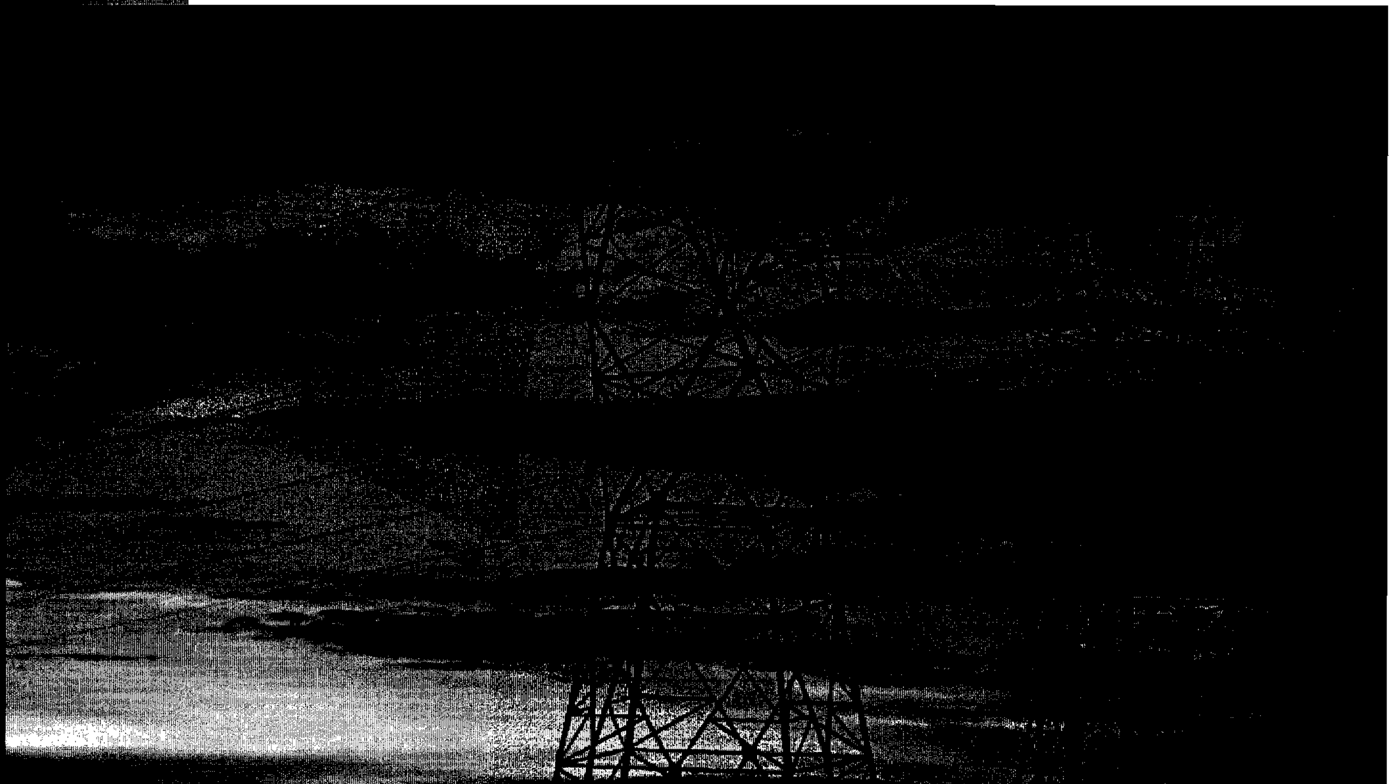
Figures

Tables

Attachments

***CEII protected information is available upon request and in accordance with ColumbiaGrid CEII policies at (http://www.columbiagrid.org/basecases-results-documents.cfm)*



Executive Summary

ColumbiaGrid was formed in 2006 to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid. ColumbiaGrid's Planning and Expansion Functional Agreement (PEFA) was developed to support and facilitate multi-system transmission planning through an open and transparent process. The Federal Energy Regulatory Commission (FERC) accepted the agreement April 3, 2007, noting support for ColumbiaGrid's effort to coordinate planning on a regional basis and to implement a single planning process for both public utility and non-public utility transmission providers. Nine parties have signed PEFA. Any interested person can participate in ColumbiaGrid's open planning process.

One of the primary activities outlined under PEFA is development of a biennial plan that looks out over a ten-year planning horizon and identifies projected transmission needs on the systems of parties to the agreement. ColumbiaGrid began work on a Biennial Transmission Expansion Plan shortly after PEFA was signed. The first System Assessment was completed in April of 2008 and the first ColumbiaGrid Biennial Transmission Expansion Plan was completed in December of 2008. The ColumbiaGrid Board of Directors approved the plan on February 18, 2009.

A significant feature of ColumbiaGrid's Biennial Transmission Expansion Plan is its single utility planning approach. The plan is developed as if the region's transmission grid were owned and operated by a single entity. This approach results in a more comprehensive, efficient, and coordinated plan than would otherwise be possible if each transmission owner completed a separate independent analysis.

This ColumbiaGrid 2009 System Assessment Report covers the first phase of the annual ColumbiaGrid planning process: an evaluation of the transmission grid through the ten-year planning horizon.

For the assessment, ColumbiaGrid developed comprehensive computer models to test the adequacy of the grid under a wide variety of future system conditions. The work also entailed compiling forecasts for loads, resources, and transmission facilities, which are key assumptions that form the basis for the power flow models studied.

ColumbiaGrid used the output of the modeling to gauge the performance of the transmission system. The results were compared to standards adopted by the North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC), and the individual transmission system owners.

In completing this assessment, the study participants held numerous full-day meetings and conference calls. A typical meeting had 20 participants. ColumbiaGrid planning engineers developed the series of power flow models that were used in the assessment from standard WECC base cases. These cases were modified to correct errors, update the system topology, and to more precisely model the system conditions of interest (e.g., Extreme winter conditions).

Using these cases, the planning engineers' simulated contingencies, documented cases where the system performance did not meet the standards, coordinated the review of each of these potential violations, and recommended further analysis and/or formation of a ColumbiaGrid study team to develop plans to mitigate the problems identified. ColumbiaGrid included a high-level assessment of non-transmission alternatives where viable to address potential violations such as load tripping, redispatch, etc.

The initial assessment results identified a large number of general areas of concern. All of the facility overloading conditions on 115 kV and above facilities were identified and mitigated with either currently planned projects or placeholder projects that will be the assumed mitigation until transmission owner planned projects can be identified. All 230 kV and above stations with voltage excursions following contingencies that exceeded the WECC criteria of a 5% change for a Category B contingency (single contingency) or 10% for a Category C contingency (double contingency) were identified and mitigated. Voltage violations on lower voltage facilities were left to the individual facility owners to mitigate.

Two tables were created showing the interim mitigation and are included later in this report. Table 3 shows the transmission owner identified mitigation projects for addressing potential overloading conditions. Table 4 shows the interim mitigation for addressing the voltage violations identified at 230 kV and above.

In addition to these projects, the studies identified 125 line sections at 115 kV that are owned by ColumbiaGrid Planning participants that could become overloaded under contingency conditions. Each of these line sections will be reviewed in subsequent System Assessments and projects to address this potential overloading will be developed as required. In the interim, "placeholder" projects were identified to address the potential violations. These placeholder projects assume that the line sections will be rerated, reconductored, or rebuilt to address the overloading concern.

Areas of concern were identified for those areas that would require planning decisions within the next planning cycle. For areas that only effect a single transmission owner, it is left to that owner to develop the final mitigation plans. For violations that affect more than one ColumbiaGrid member, a ColumbiaGrid study team may be formed to develop the final mitigation. The final mitigation for these areas of concern will be included in the Biennial Transmission Expansion Plan Update, which will be completed in early 2010.

As discussed in the Study Results section of this report, five areas of concern were identified that affect more than one ColumbiaGrid planning participant. The first two of these areas (Voltage issues on the Olympic Peninsula and potential overloading on the Olympia-Shelton 230 kV #5 line) will require the formation of a new study team. The third and fourth items (potential overloading on the Olympia-Chehalis 230 kV line and the need for an additional Puget Sound area 500/230 kV transformer) can be addressed using the existing Puget Sound Area Study Team. The fifth item, developing a plan to reinforce the West of Cascades Paths, will require the formation of a new study team.

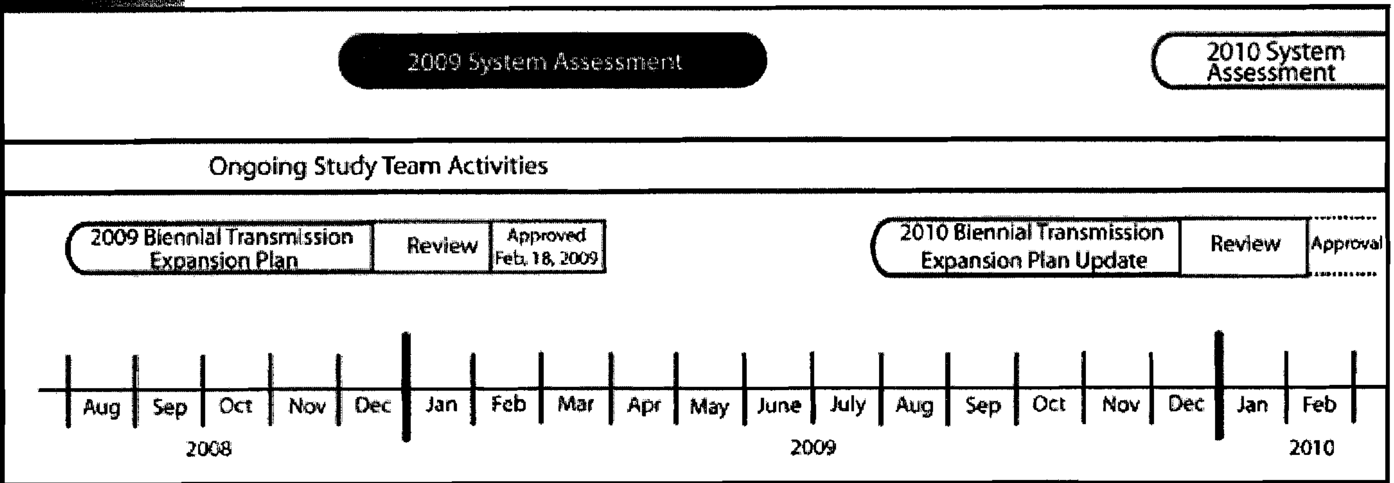


Figure 1 - Process Timeline

Introduction

ColumbiaGrid was formed with seven founding members in 2006 to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid. Nine parties have signed ColumbiaGrid's Planning and Expansion Functional Agreement (PEFA) to support and facilitate multi-system transmission planning through an open and transparent process.

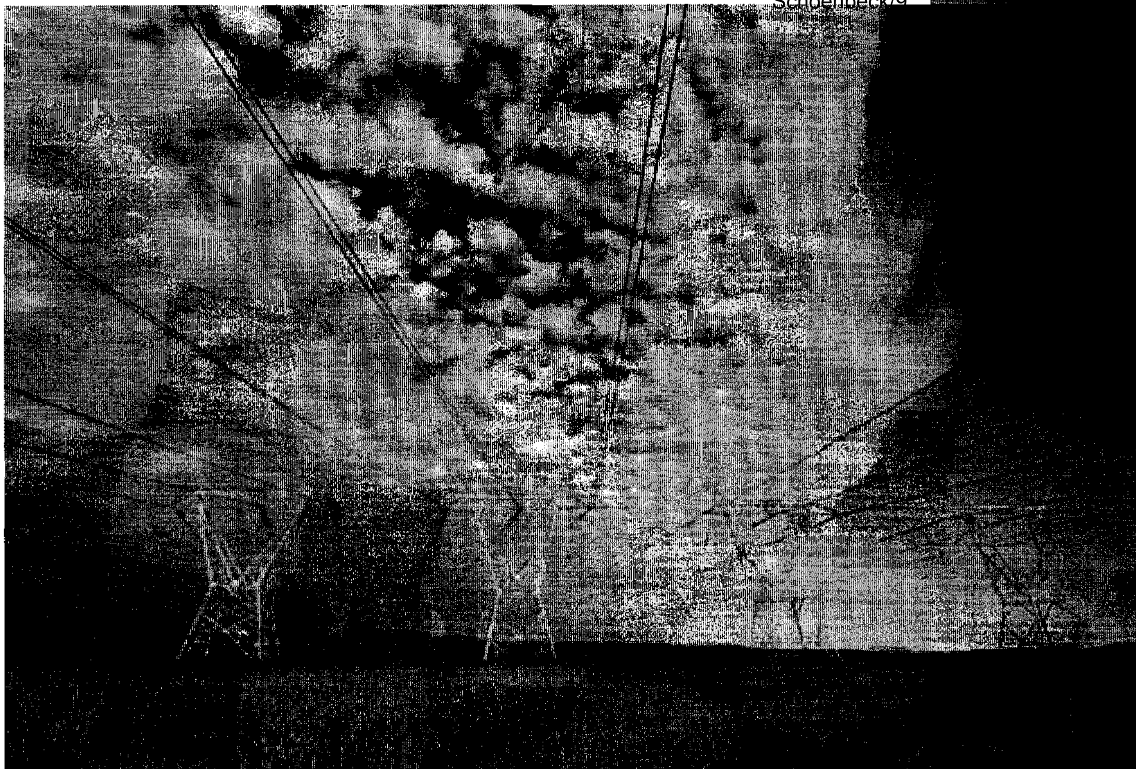
One of the primary activities outlined under PEFA is development of a biennial plan that looks out over a ten-year planning horizon and identifies projected long-term firm transmission needs on the systems of parties to the agreement. ColumbiaGrid began work on the plan shortly after PEFA was signed. The first system assessment was completed in April of 2008 and the first ColumbiaGrid Biennial Transmission Expansion Plan was completed in December of 2008. The ColumbiaGrid Board of Directors approved the plan on February 18, 2009.

A significant feature of the ColumbiaGrid Biennial Transmission Expansion Plan is its single-utility planning approach. The Biennial Transmission Expansion Plan is being developed as if the region's transmission grid were owned and operated by a single entity. This approach will result in a more comprehensive, efficient, and coordinated plan than would otherwise be developed if each transmission owner completed a separate independent analysis.

PEFA requires that "ColumbiaGrid, in coordination with the Planning Parties and Interested Persons, shall perform a system assessment through screening studies of the Regional Interconnected Systems using the Planning Criteria to determine the ability of each (Party's system) to serve, consistent with the Planning Criteria, its network load and native load obligations, if any, and other existing long-term firm transmission service commitments that are anticipated to occur during the Planning Horizon." The assessment is required to be completed annually.

The ColumbiaGrid system assessment described in this report was designed to meet those requirements. It is the first phase of the Biennial Transmission Expansion Planning process. The system assessment process timeline is shown in Figure 1. As with other ColumbiaGrid activities, the assessment was conducted in an open process. (See the sidebar for further information.)

This ColumbiaGrid 2009 System Assessment Report describes an evaluation of the transmission grid. The assessment began with developing comprehensive computer models to test the



adequacy of the planned grid under a wide variety of system conditions. This included forecasts for loads, resources, and transmission facilities, which are key assumptions and the building blocks for the cases that were analyzed.

For the assessment, ColumbiaGrid Planning engineers gauged the performance of the system using these models, and the results were compared to standards adopted by the North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC), and by individual transmission system owners.

The NERC, WECC, and owner-adopted standards require that the system be able to continue to function within a specific range of voltages and with transmission loading below facility ratings under a wide variety of operating conditions. These operating conditions include events such as a loss of a transmission line and/or substation facility and various weather patterns.

ColumbiaGrid's planning engineers studied over 4000 contingencies through the computer models for each system base case model to complete the system assessment. In cases where the system performance did not meet NERC, WECC, and owner standards, ColumbiaGrid recommended a strategy to resolve the problem, including formation of a ColumbiaGrid Study Team charged with developing plans to mitigate the identified system performance concern, or further analysis, including sensitivity studies.

****

At the outset, notice of the system assessment was sent to the ColumbiaGrid 'Interested Persons" list. The process for the assessment was developed and implemented in an open and transparent manner, and meetings were open to all interested participants. The results of the assessment studies were analyzed in a joint effort by all participating entities.

Meeting materials were posted on the ColumbiaGrid website, except when information was determined to be Critical Energy Infrastructure Information (CEII). CEII was made available through a password protected area on the website and access was granted to participants upon request. To acquire a password and access CEII data, entities were required to sign and comply with ColumbiaGrid Non-disclosure and Risk of Use Agreements. In compliance with WECC requirements, WECC base cases were only available to WECC members through the password-protected portion of the ColumbiaGrid website.

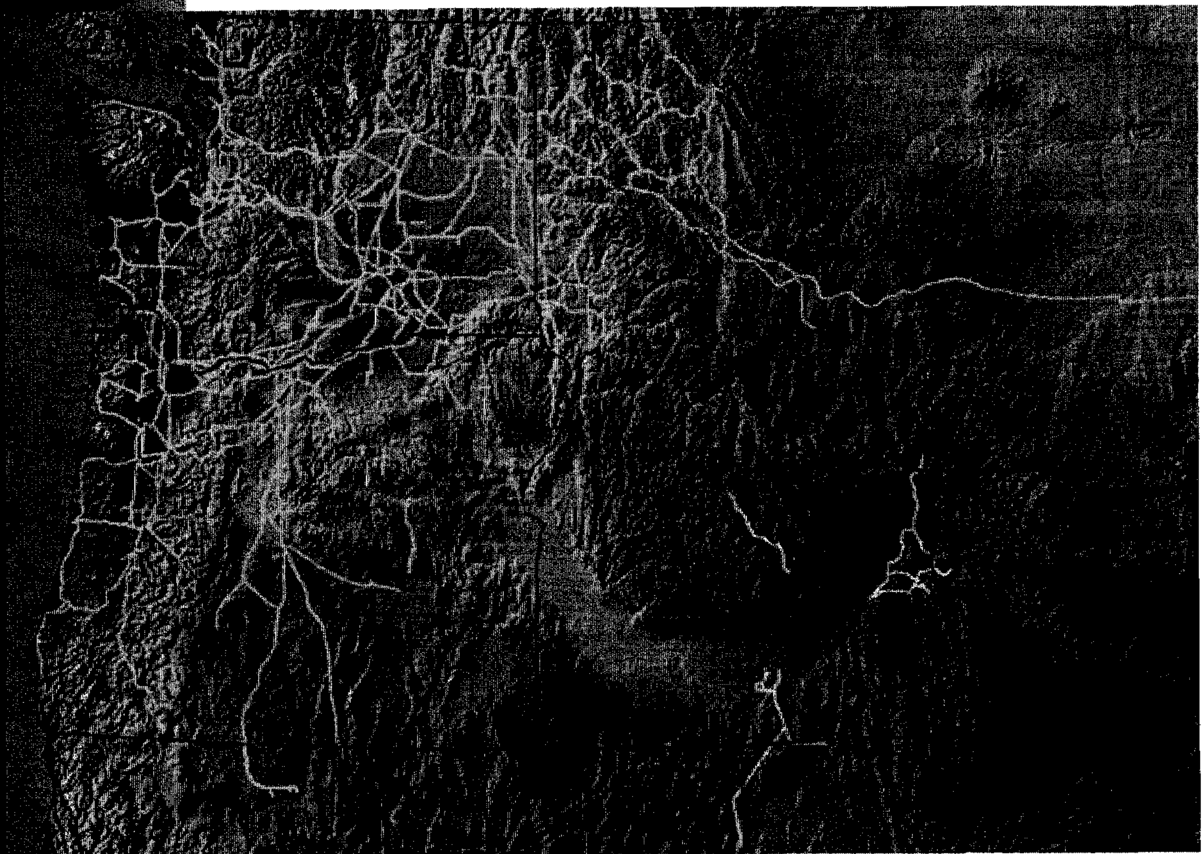


Figure 2 - Member Facilities

System Assessment Process

The parties to ColumbiaGrid's PEFA are: Avista Corporation, Bonneville Power Administration (BPA), Chelan County PUD, Cowlitz County PUD, Grant County PUD, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power. The combined facilities of these participants are shown in Figure 2.

*****

ColumbiaGrid's system assessment focused on the ability of the physical transmission grid to meet customers' needs under a wide range of conditions. This analysis identifies those projects needed for system reliability. However, transmission projects may provide other benefits than preserving basic system reliability. For example, a project that enables customer access to lower-cost generating resources could have the benefit of lowering consumer bills. Such an "economic project" would be worth consideration if the cost reduction to consumers exceeds the cost of the project. This system assessment does not include the economic studies needed to identify economic projects. ColumbiaGrid is, however, working through WECC to complete those types of analyses. As economic projects are identified, they will be added to the ColumbiaGrid biennial plan.

The Northwest transmission grid is interconnected and as result, it was necessary for all Northwest entities to participate in the system assessment whether or not they are parities to the ColumbiaGrid PEFA. Major transmission owners in the Northwest were notified individually and encouraged to participate in the system assessment process. All participants in the system assessment, who provided input to the study or helped to screen results, had access to the same information, whether or not they were parties to PEFA.

Study Assumptions

The major assumptions that form the basis of the system assessment are load, generation, external path flows, and planned transmission additions. These assumptions were used to develop the cases that were studied in the assessment. The approach used for developing each of these assumptions is summarized below.

Basecase Development

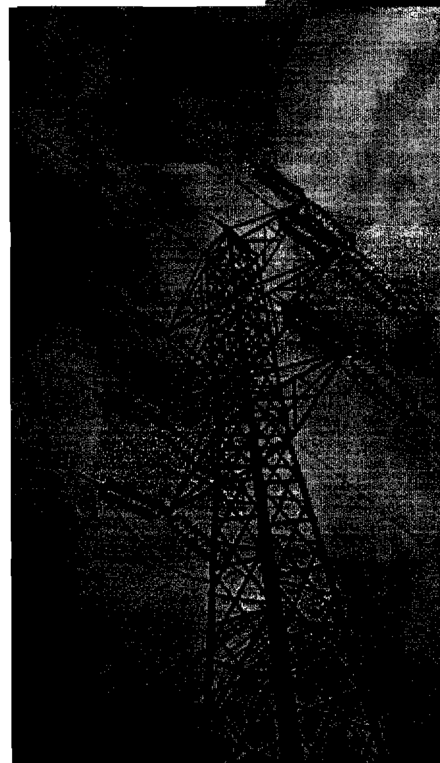
To cover the ten-year planning horizon, ColumbiaGrid developed five and ten-year base cases for winter peak load, winter extreme peak load, and summer peak load conditions. Once the base cases were established, the base case transmission system, with no outages, was analyzed to ensure it met planning standards. Deficient areas were noted and corrections or updates were made as appropriate.

To create the five-year cases, approved WECC base cases were used as a starting point. After surveying the available cases, the recent 2014 Heavy Winter case (14HW1) and the 2013 Heavy Summer case (13HS1) were chosen. Corrections and updates were made to these cases to ensure that they would be as accurate as possible. Ten-year planning cases were not available from WECC when the system assessment was initiated.

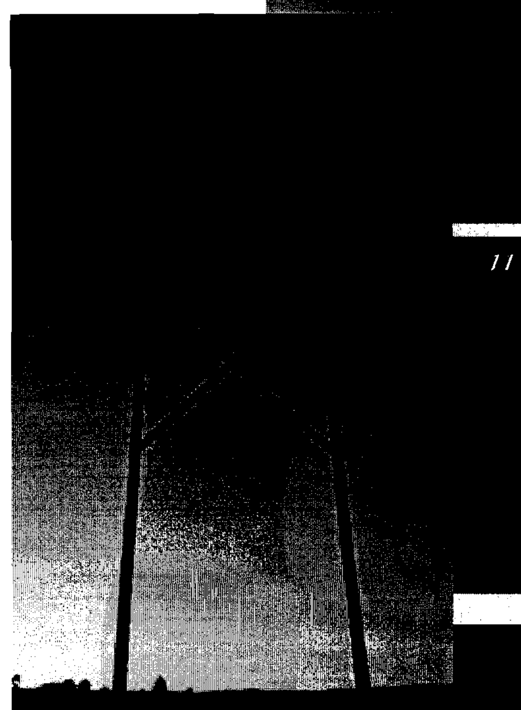
All of the base case assumptions, such as the load levels modeled, the generation pattern modeled and the transmission configuration, were selected by the ColumbiaGrid Planning group during open meetings.

Load Modeling Assumptions

As required in the NERC Reliability Standards, the transmission system is planned for expected peak load conditions. In addition, some study participants have planning criteria that requires their system to be capable of meeting abnormally cold weather loads. This additional requirement is a result of the prevalence of electric heat in the region, particularly in the west side load areas. Normal summer and winter peak loads were based on a probability of 50 percent not to exceed the target load peak,

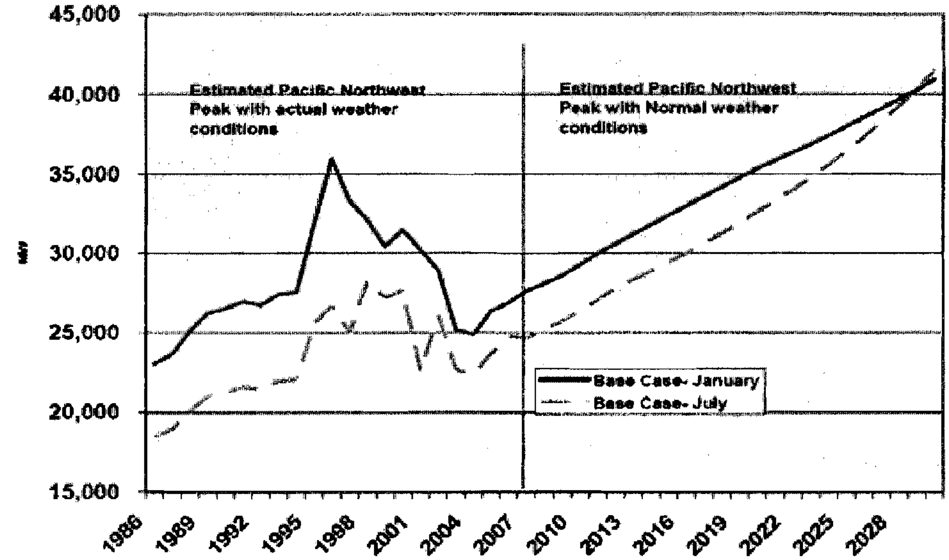


Participants reviewed the loads in the 13HS1 and 14HW1 cases. These cases, although recently approved, were developed prior to the recent economic downturn. Participants expect a slowing on load growth in the short term and felt that these two cases would be representative of the five-year time horizon without any change to the loads modeled.



To create the ten-year winter case, the loads in the five-year winter case were increased. It was anticipated that the economy would improve and recover fully in the five to ten-year time frame. For that reason, the ten-year base cases were created from the five year cases by adding seven years load growth to capture the economic recovery of what load should have been in place in the five-year case plus the subsequent 5 years. This load increase from the five-year to the ten-year case was forecast to be 12.9% (1.75% for 7 years for the winter case). To create the ten-year summer case, the loads in the five-year summer case were increased by 16.9% (2.25% per year for 7 years). The annual increases (1.75% and 2.25%) were obtained from the Northwest Power and Conservation Council Draft Demand Forecast

The Northwest Power and Conservation Council Draft Demand Forecast



The Northwest Power and Conservation Council Draft Demand Forecast dated February 13, 2009 was the basis for the load growth projections between the five and ten year cases. According to this forecast, the regional peak load is expected to grow from 29,500 in 2010 to around 42,000 MW by 2030. The region is expected to become summer peaking by 2029 if not sooner. The growth rate for the winter peak loads is expected to be 1.7 to 1.9 percent per year. The growth rate for the summer peak loads is expected to be between 2.2 and 2.3 percent per year. Using this information, participants in the ColumbiaGrid System Assessment agreed to use 1.75% growth rate for winter peak load studies and 2.25% for summer peak load.

dated February 13, 2009. See sidebar above.

Given these assumptions, the total winter peak load for the Northwest system is expected to be 33,023 MW in the five-year case. The forecast summer peak load for the five-year case is lower than winter at 26,490 MW. While the Northwest system as a whole peaks in the winter, this does not mean that summer conditions require less attention. The capacity of electrical equipment is often limited by high temperatures, which means the equipment has lower capacity in summer than in winter. As a result, it is possible that a lower summer load can be more limiting than a higher winter load due to the ambient temperature differences and the impact on equipment.

To facilitate power flow solutions in the ten-year cases since there were no transmission additions included to support this load growth, all load was modeled at unity power factor which means they are represented by only real power and no reactive component. This assumes that reactive power compensation will be provided at the distribution level rather than the transmission level. As a result, more reative power support may be necessary than these study results suggest. These reactive power support additions will be reviewed and revised as necessary in subsequent system assessments. The total winter peak load for the Northwest system is modeled at 36,804 MW in the ten-year case. The forecast summer peak load for the ten-year case is 30,340 MW.

Extreme peak loads for abnormal winter conditions were based on a probability of 95 percent not to exceed the target load peak. The abnormal winter peak cases assumed cold weather in the Pacific Northwest footprint only (primarily Oregon, Washington and Northern Idaho). British Columbia, southern Idaho, Montana, Wyoming, and Utah were modeled with normal winter peak loads, and due to the physical separation of these systems, it was determined that this assumption would not impact the performance of the transmission system within the Pacific Northwest footprint. The main impact of this assumption would be resource availability from neighboring regions and not transmission system performance.

To represent the abnormal winter condition, load increases of about 12% have been used in the past based on analysis completed by Battelle NW. This increase is very similar to the 12.9% increase in the ten-year case, so 12.9% was used for the five-year abnormal winter case. The 14HW1 case was modified to represent an abnormal winter load condition by increasing the loads by 12.9%, only the real component of the load was increased.

The extreme winter peak load forecast total for the Northwest in the five-year case is 36,804 MW. To model the ten-year extreme weather case, a 27.5% increase in loads over the five-year normal winter case was modeled. For the ten-year case, this results in a northwest load of about 41,073 MW.

Resource Modeling Assumptions

Resource additions ten years into the future are much more difficult to forecast than loads. Although there are numerous potential generating projects in the region in various stages of development, there is much uncertainty for a variety of reasons about whether and when they will come into service. Many of the variables are outside the control of transmission providers. Adding to the complexity, these resource assumptions are particularly important. Depending upon their location, some resources can mask transmission problems while others can create new problems.

For last year's system assessment, the assumption was made to model only resources with firm transmission contracts. The existing resources with firm transmission contracts in the region are adequate to meet summer peak load and firm export requirements in the five-year time frame. However, for the ten-year summer case, exports to California were reduced by 3,500 MW to 2,700 MW on the COI and 1,500 MW on the PDCI. A sensitivity study is planned for later in the year, when updated ten-year planning basecases are available from WECC, to study the California Interties at their firm commitment level. Additional Northwest wind generation resources will be used to model this increase in transfers.

While the existing northwest resources are adequate to meet summer loads, they are not adequate to meet winter peak loads. Northwest utilities rely on seasonal diversity in resource needs with other regions to meet winter load obligations by importing from California and the Southwest.

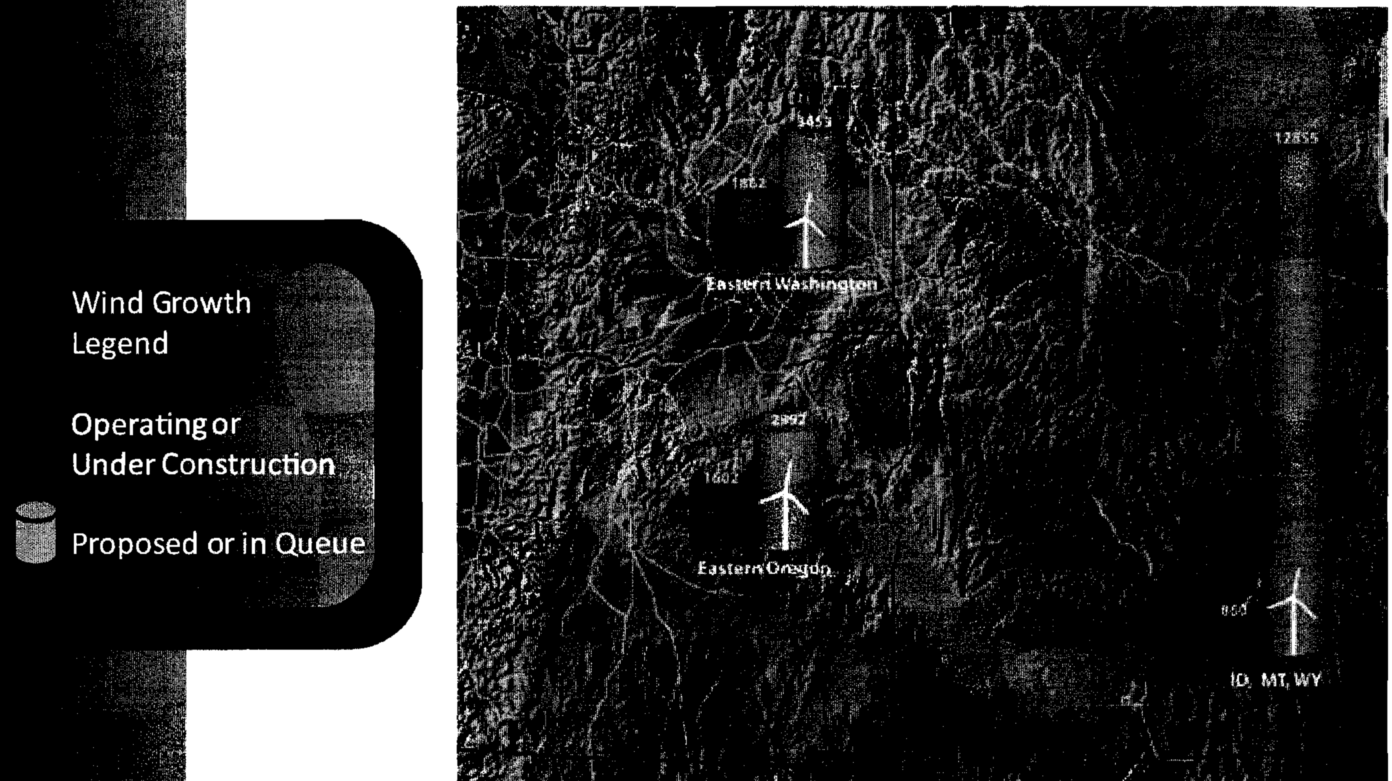


Figure 3 - Existing and Proposed Wind Resources

Several combustion turbine projects have been built recently in the Northwest that do not have firm transmission commitments, including Big Hanaford and Grays Harbor. Both projects are located in Washington state. Big Hanaford is located in the Chehalis area and Grays Harbor is located near Aberdeen. There are many indicators, including the number of requests for interconnection that transmission providers have received in recent years, to suggest that other resources will be developed in the region during this ten-year planning horizon. The addition of proposed generation projects, especially thermal projects on the west side of the Cascades, could have a significant impact on the performance of the transmission system and reduce the reliance on California imports that was assumed in the winter cases. Planned transmission projects will be reviewed periodically to determine whether changes in resource additions would impact the need for, or scope of, these projects.

The high load level in the extra-heavy winter base case resulted in significant low voltages in the Centralia/Olympic Peninsula area, a sign of system problems. The West of Cascades flows in this case were also near or above the present-day operating transfer capability (OTC) limit, which could be the cause of the depressed voltages. Due to this system stress and the likelihood that additional resources will be added on the system in the next ten years, the resource assumptions for this assessment were changed from last year. The two existing resources mentioned above that do not have firm transmission contracts, Big Hanaford and Grays Harbor, were assumed to be operating during both winter conditions.

There is a significant amount of new wind generation proposed in the ColumbiaGrid footprint. Figure 3 shows the existing wind resources, along with projects under construction and projects proposed as of May 2009.

Although there are several thousand MWs of wind generation in the Northwest, none was modeled during the peak load conditions in the system assessment. Historical operation has shown there is often little wind generation during either winter or summer peak load conditions. Operation without wind generation results in increased reliance on local gas generation and/or increased imports from California and the southwest. ColumbiaGrid will perform sensitivity studies with higher levels of wind generation, to test these other possible system conditions.

Although there is significant wind generation potential in eastern Washington and Oregon, there is much more potential in Idaho, Montana, and Wyoming. The required transmission additions to serve those remote resources are much greater, however, very limited new transmission capability is planned to enable these wind resources to reach the Northwest.

For the extreme winter conditions, some additional generation was added in the northwest to offset the increase in imports that would be needed from the southwest. Generation at the storage projects (Libby, Hungry Horse, and Dworshak) was increased along with three additional thermal units that had been off at Rathdrum, Beaver, and Finley. These changes resulted in an additional 970 MW of generation in the northwest. In addition to the thermal generation, some wind generation was included in the extreme winter cases. All of the existing wind projects in the northwest were increased pro-rata to obtain 1,700 MW. These generation assumptions relieved some of the stress that would occur on the system due to imports from California for these extreme winter conditions. Although high wind generation is unlikely, some wind generation is expected during peak load conditions so this assumption is plausible.

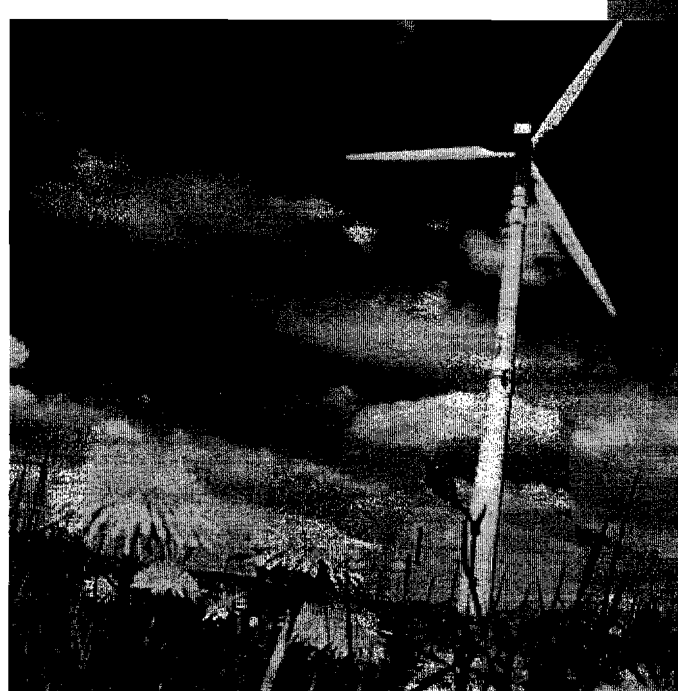
In the five-year normal winter case, ColumbiaGrid assumed 743 MW was imported into the Northwest over the Pacific DC Intertie and the California-Oregon Interties. In the extra-heavy winter case, the import over these facilities increased to 4,614 MW, an assumption that results in high stress to the transmission system and shows the upper bound of the transmission system needs. For the ten-year normal winter study, ColumbiaGrid assumed 4,618 MW was imported into the Northwest on the combined interties. In the extra-heavy winter case, the import over these facilities increased to 6,475 MW.

No retirement of existing resources has been identified or included in the base cases. A list of the resources used in each base case is included in Attachment A.

Transmission Modeling Assumptions

As required by the NERC Reliability Standards and PEFA, it was necessary to model firm transmission service commitments in the system assessment. PEFA requires that plans need to be developed to address any projected inability of the PEFA planning parties' systems to serve the existing long-term firm transmission service commitments during the planning horizon, consistent with the planning criteria. The NERC reliability standards do not allow any loss of demand or curtailed firm transfers for Level B contingencies (single elements) and allow only planned and controlled loss of demand or curtailment of firm transfers for Level C contingencies (multiple elements).

The ColumbiaGrid planning process assumes that all ColumbiaGrid members' transmission service and native load customer obligations represented in WECC and ColumbiaGrid base cases are firm, unless specifically identified otherwise (such as interruptible loads).

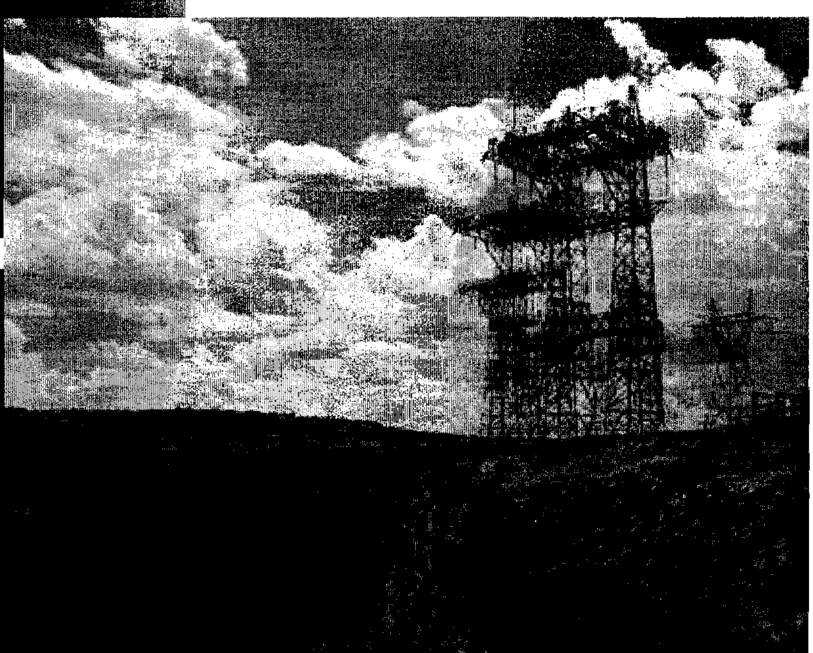


The firm transmission service commitments between the Northwest and areas outside the Northwest are scheduled on specific transmission paths (e.g., British Columbia-Northwest, Montana-Northwest, Idaho-Northwest, California-Oregon Interties, and Pacific DC Intertie). These external paths were modeled at loading levels at least as high as their known firm transmission service commitments.

Conversely, the transmission paths internal to the Northwest are not scheduled. The flows on internal paths are a result of flows on the external paths, internal resource dispatch, internal load level, and the transmission facilities that are in service.

Of the external paths, the British Columbia-Northwest and the two California Interties are most crucial during peak load conditions. These paths are bidirectional and there are often different stresses during winter and summer conditions. The Montana-Northwest and Idaho-Northwest paths are stressed more during off-peak load conditions and are less important during peak load conditions. The adequacy of these latter paths is verified annually through operational studies.

During the winter, returning the firm Canadian Entitlement to British Columbia is the predominant stress on the Puget Sound area and the British Columbia-Northwest path. ColumbiaGrid modeled 1,500 MW of firm transfers on this path to represent the long-term firm transmission service commitments expected throughout the planning horizon due to the Canadian Entitlement and those of Puget Sound Energy.



In the summer, transfers on the British Columbia-Northwest and California Interties are typically in the opposite direction as in winter. Surplus power resources from Canada and the Northwest are often sent south to California and the Southwest.

There are 7,700 MW of projected firm north-to-south capacity rights on the combined California-Oregon Interties and Pacific DC Intertie in the five-ten year planning horizon.

There are presently 1,335 MW of firm transmission rights in the north-to-south direction on the British Columbia-Northwest path. In addition, significant amounts of short-term firm power are sold on this path to move surplus resources south. Although the short-term firm product is available for a maximum of 11 months, this type of transmission use is expected to continue.

Combining the long-term and short-term firm use, 2,600 MW was modeled on the British Columbia-Northwest path in the north to south direction. ColumbiaGrid recognized that there are not long-term firm transmission service commitments in place today for that level of use and this needs to be taken into consideration when analyzing the study results.

The path flows in the assessment were within their limits, with a few exceptions. The West of Cascades South path exceeded its posted OTC by over 400 MW during the extreme winter condition in the five-year case and in both ten-year cases. The West of Cascades North path was also slightly over its posted OTC during this same ten-year extreme winter condition. The South of Allston path was near its limit in the summer case. The assessment provided an indication of upgrades that might be needed on these paths

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The Canadian Entitlement grew from a 1960s treaty between the United States and Canada. Under the treaty, the two countries cooperatively developed water resources in the Canadian portion of the Columbia River Basin. The storage dams built in British Columbia allowed for more generation at power plants downstream in the United States. The two countries agreed that in return for building the storage, Canada was entitled to half of the increase in power generated at existing dams in the United States.

Canada's share of the power was originally sold to utilities in the United States. But when the 30-year sales agreements expired, the countries agreed that this large block of power would be returned to British Columbia. Canada's half of the downstream power benefits, the Canadian Entitlement, is forecast to be 1,350 MW during peak load conditions in 2018. The delivery of the entitlement from the United States to Canada affects transmission operations considerably on facilities on the Northern Intertie and in the greater Puget Sound area.

to accommodate these flow levels. The West of Hatwai and West of McNary flows are quite low in these cases but that is expected, as these paths typically experience stress during off-peak conditions.

The background for the specific existing firm transmission service commitments on members' paths that were modeled in the Transmission Expansion Plan is as follows:

1. Canada to Northwest Path

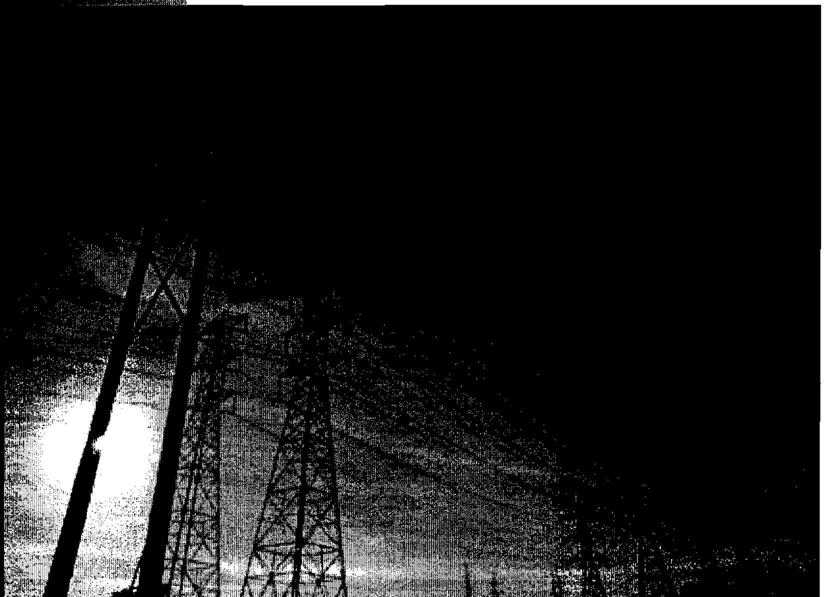
The capacity of this path in the north-to-south direction is 2,850 MW on the westside and 400 MW on the eastside for a total transfer capability of 3,150 MW. The total capacity of the path in the south-to-north direction is 2,000 MW, with a limit of 400 MW on the east side. Both of these directional flows can impact the ability of the system to serve loads in the Puget Sound area.

The Canadian Entitlement return is the predominant south-to-north commitment on this path and is critical during winter conditions. Although the total amount of commitment varies somewhat, 1,350 MW of firm transmission service commitments is projected for the 2020 studies. Puget Sound Energy also has a 200 MW share at full transfer capability into British Columbia, which translates to a 130 MW allocation at the 1,350 MW level. Bonneville has committed to maintaining this pro-rata share of the Intertie above its firm transmission service commitments.

Both of these firm transmission service commitments are on the west side of the path. To model them in the winter case, the British Columbia-Northwest path was scheduled at 1,500 MW into Canada on the west side. No flow was modeled on the east side portion of the British Columbia-Northwest path.

With reduced loads in the Puget Sound area in the summer, the return of the Canadian Entitlement is not typically a problem. The most significant stressed condition in the summer is north-to-south flows of Canadian resources to meet loads south of the border when the thermal capacity of the electrical facilities in the area is reduced.

Powerex has long-term firm rights for about 242 MW for their Skagit contract, plus 193 MW to Big Eddy and 450 MW to John Day, for a total of 885 MW in the north–to-south direction. Powerex also owns the reassignment for the Cherry Point rights (200 MW) which is just south of the Canadian border and can be reassigned to the border. Puget Sound Energy has long-term firm contracts for 150 MW, and Snohomish has firm contracts for 100 MW.



In addition to this 1,335 MW of long-term firm commitments, significant amounts of short-term firm transmission service are typically purchased for additional transfers. These short-term firm transmission service commitments last only 11 months; however, they can be repurchased depending upon availability. This study assumes that this level of transmission service commitments will continue in the foreseeable future.

To cover all firm transmission service commitments, both long and short-term, the British Columbia-Northwest path was scheduled to 2,600 MW in the summer all on the west side. The 2008 System Assessment placed 300 MW of this transfer on the eastside of the path but no system problems were noted for that condition. This year's assessment is testing loading only on the westside path which is equally plausible.

2. Montana to Northwest Path

This path is rated at 2,200 MW east-to-west and 1,350 MW west to east. The predominant flow direction is east-to-west. The path can only reach its east–to-west rating during light load conditions. Imports into Montana usually only occur when the Colstrip Power Plant facilities are out of service.

The firm commitments on this path exceed 1400 MW east to west. There are also some counter-schedules that reduce the actual flows on the system. For the five-year studies, flow was modeled as 1,327 MW in normal winter, 1,402 MW in extra-heavy winter, and 1,007 MW in summer. Flows are similar in the ten year case.

3. Northwest to California/Nevada Path

The combined COI and Pacific DC Intertie are rated at 7,900 MW in the north-to-south direction, although there are some limitations to operation due to the North of John Day nomogram. The COI is individually rated at 4,800 MW and the Pacific DC Intertie is rated at 3,100 MW. The 300 MW Alturas tie from Southern Oregon into Nevada utilizes a portion of the 4,800 MW COI capacity. In the south-to-north direction, the COI is rated at 3,675 MW and the Pacific DC Intertie is rated at 3,100 MW.

Bonneville is planning upgrades to these paths to increase the potential to use these paths at their full capability. After these upgrades, the long-term firm transmission service commitments on these paths are expected to total about 7,700 MW, which is what was modeled in the summer case used in the System Assessment.

There are some firm transmission service commitments on this path in the south–to-north direction but not a significant amount.

Non-firm sales are relied on by many parties in the winter, especially during very cold weather, when there are insufficient resources within the Northwest to meet the load level. For the base cases, Northwest resources were dispatched first, and firm transmission service commitments were modeled on all other external paths. Then additional resources needed to meet the remaining load obligations in the Northwest were imported from the south on the COI and Pacific DC Intertie.

In the five-year heavy winter base case, the combination path was loaded to 743 MW into the Northwest with 449 MW on the COI and 294 MW on the Pacific DC Intertie. For the extra-heavy five-year winter base case, the total path was loaded to 4614 MW with 2,366 MW on the

COI and 2248 MW on the PDCI. In the ten-year case, the combined imports increased to 6475 MW. The five-year summer case has a total of 7709 MW on the combined path while the ten-year summer case flows are 4207 MW.

4. Idaho to Northwest Path

The Idaho to Northwest path is rated at 2,400 MW east-to-west and 1,200 MW west-to-east. This path has about 300 MW of firm schedules into Idaho to meet firm transfer loads, in addition to a 100 MW point-to-point service contract. Summer conditions with flows at these levels are typical as there are few surplus resources to export from the east. In the winter, these transfer loads are reduced, and PacifiCorp typically exports its east side resources into the Northwest to meet its west side load obligations. Due to the nature of the flows from Idaho, they are not expected to cause significant system problems during peak load periods.

For the five-year winter cases, 664 MW is modeled flowing into the Northwest. In the extra-heavy winter case, 611 MW is modeled. In summer, 61 MW was modeled. Flows were very similar in the respective ten-year cases.

5. West of Hatwai Path

The West of Hatwai path is rated at 4,277 MW in the east-to-west direction but it is not a scheduled path. This path is stressed most during light-load conditions when eastern loads are down and the excess resources from the east flow into Washington. This path is not expected to cause problems during peak load conditions. This path is loaded to 377 MW in the summer, 548 MW in winter, and 299 MW in extra-heavy winter. In the ten-year cases, the respective flows on the West of Hatwai path are 152 MW, 308 MW and 645 MW.

6. West of Cascades North and South Paths

The West of Cascades North path is rated at 10,200 MW and the West of Cascades South path is rated at 7,000 MW, both in the east-to-west direction. These paths are not scheduled paths but transfer east side resources to the west side loads. These paths are most stressed during winter load conditions, especially when west side generation is low. The north path was loaded to 3,591 MW in the five year summer base case, 8,579 MW in the winter base case, and 9,546 MW in the extra-heavy winter base case. These loadings increase to 4,558 MW, 9,494 MW 10,641 MW, respectively, in the ten-year cases. The south path was loaded to 3,836 MW in the summer base case, 6,149 MW in the winter base case, and 7,444 MW in the extra-heavy winter base case. These loadings increase to 4,826 MW, 7,456 MW and 8,888 MW, respectively, in the ten-year cases.

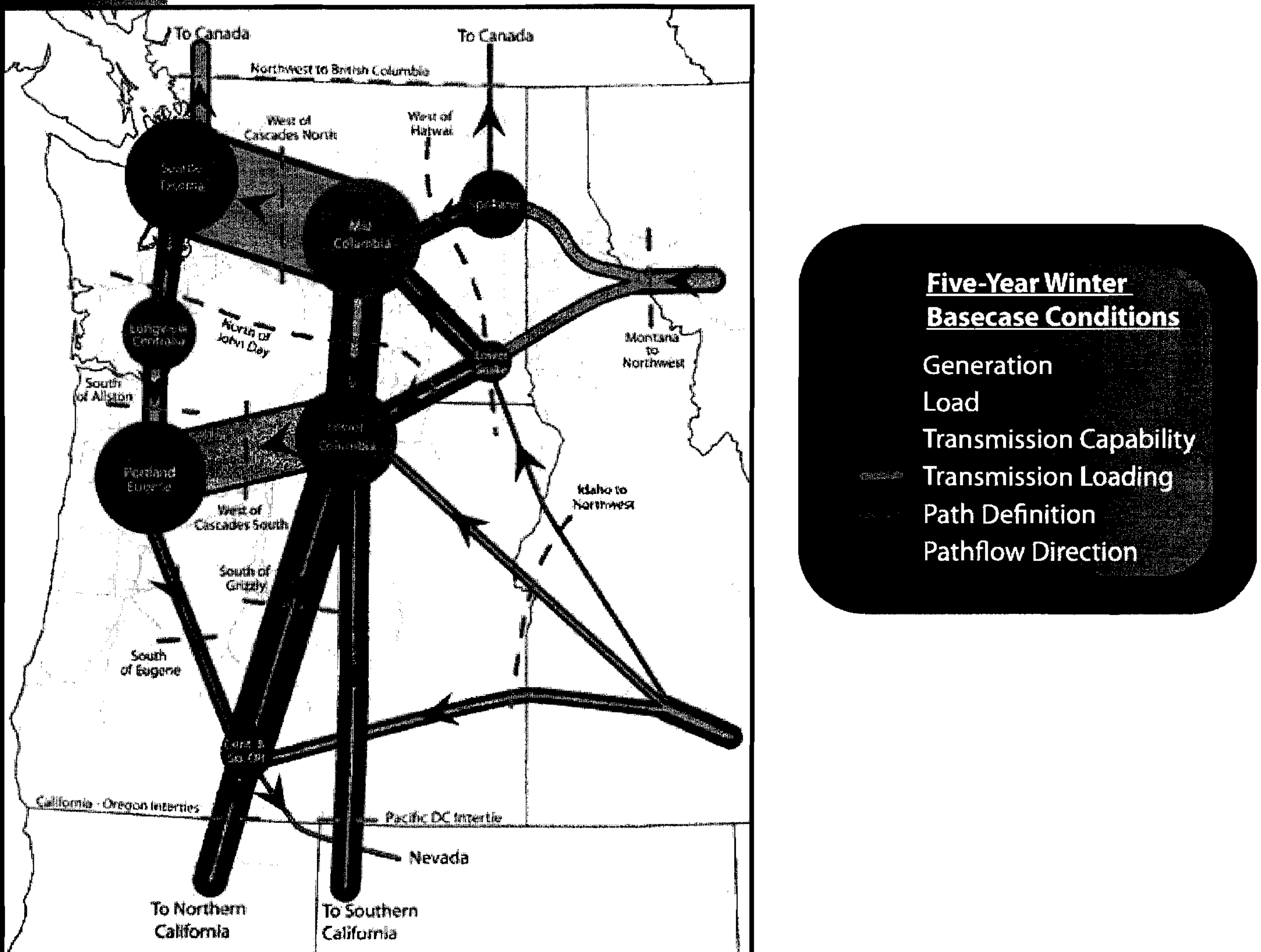
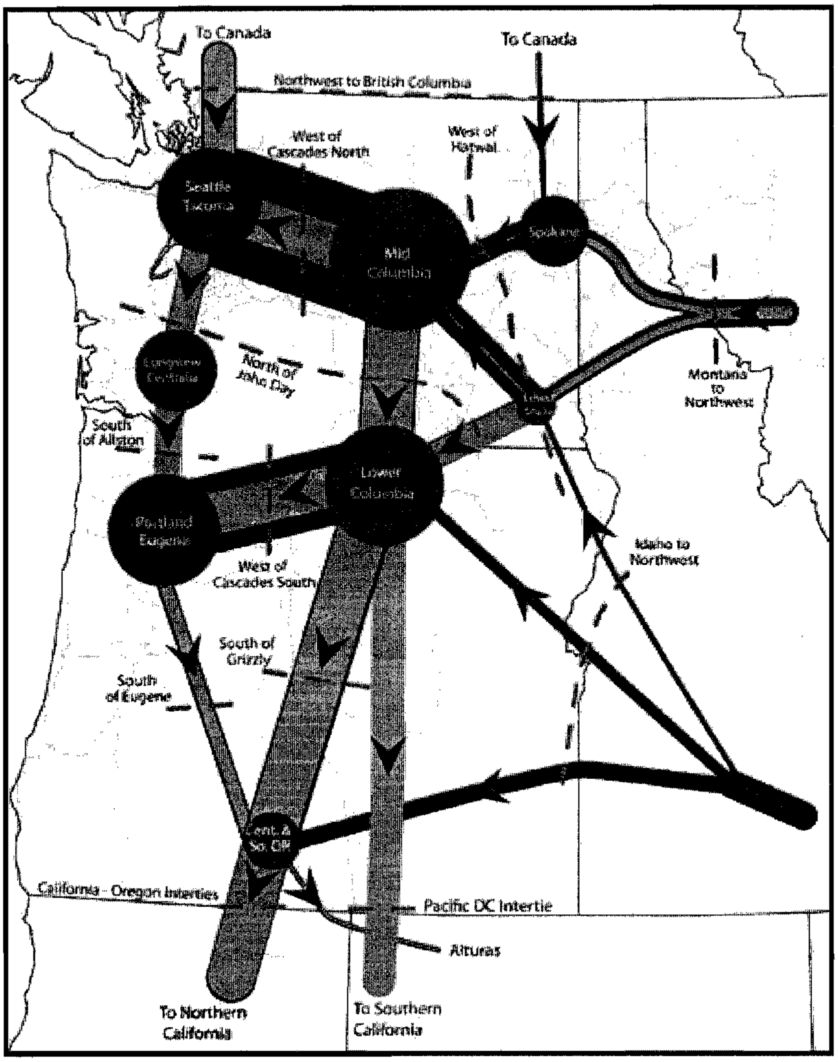


Figure 4 - Five-Year Winter Basecase Conditions

The flows modeled for winter and summer peak conditions are shown in Figures 4 and 5, respectively. The red circles in the figures represent the load levels in the identified areas; the load level is proportional to the area of the circle. The Seattle-Tacoma area includes the area west of the cascades from the Canadian border south through Tacoma. The Longview/Centralia bubble includes the areas south of Tacoma through Longview and west to include the Olympic Peninsula. The Portland/Eugene area includes the Willamette Valley and Vancouver, Washington area. The two major west side load areas, Seattle/Tacoma and Portland/Eugene, each have approximately 10,000 MW of load as shown in winter load Figure 4. The Southern/ Central Oregon bubble includes the Roseburg area down to the California border and east to the Bend-Redmond area. The Mid-Columbia Area includes load in the Washington area east of the Cascades, west of Spokane, South of the Canadian border and north of the Columbia River. The Lower Columbia bubble includes loads to the south of Mid-Columbia to Central Oregon. The Spokane area includes loads to the east in Western Montana, north to the Canadian border and south to the Oregon border. The Lower Snake bubble includes the major generation in the area.

The area of the green circles represents the amount of generation in that area. The Seattle/Tacoma and Portland/Eugene load areas have more load than generation and rely on other areas to supply the load resource balance. The Mid-Columbia,



Five-Year Summer Basecase Conditions
Generation
Load
Transmission Capability
Transmission Loading
Path Definition
Pathflow Direction

Figure 5 - Five-Year Summer Basecase Conditions

Lower Columbia and Lower Snake areas have surplus generation that is used in other areas. The Mid-Columbia area has about 11-12,000 MW of generation represented in the cases. The load/ resource ratios in the Spokane, Central/Southern Oregon and Longview/Centralia areas have greater balance.

The dark blue lines between the areas represent the major paths that connect the areas. The width of the dark blue lines represents the relative capacity of the paths. For example, the West of Cascades North path is rated at 10,200 MW. The light blue lines within these paths represent the capacity that is used in the studies. In the winter cases, the West of Cascades paths are heavily used to meet the load levels in the west side areas while the North of John Day and West of Hatwai paths are lightly loaded. The external paths to Canada, Montana and Idaho are loaded to the firm obligations on each path as discussed earlier. The downstream benefit return loads the Canada to Northwest paths to nearly their limits. Power is imported from California to provide overall load resource balance in the northwest.

The five-year summer conditions modeled in the base cases are shown in Figure 5. The load levels are typically lower in summer than in winter, especially in the west side areas, and are shown here with proportionally smaller bubbles. Central/Southern Oregon is an exception as its summer load level exceeds the winter. Also note that the Portland/Eugene area load level is

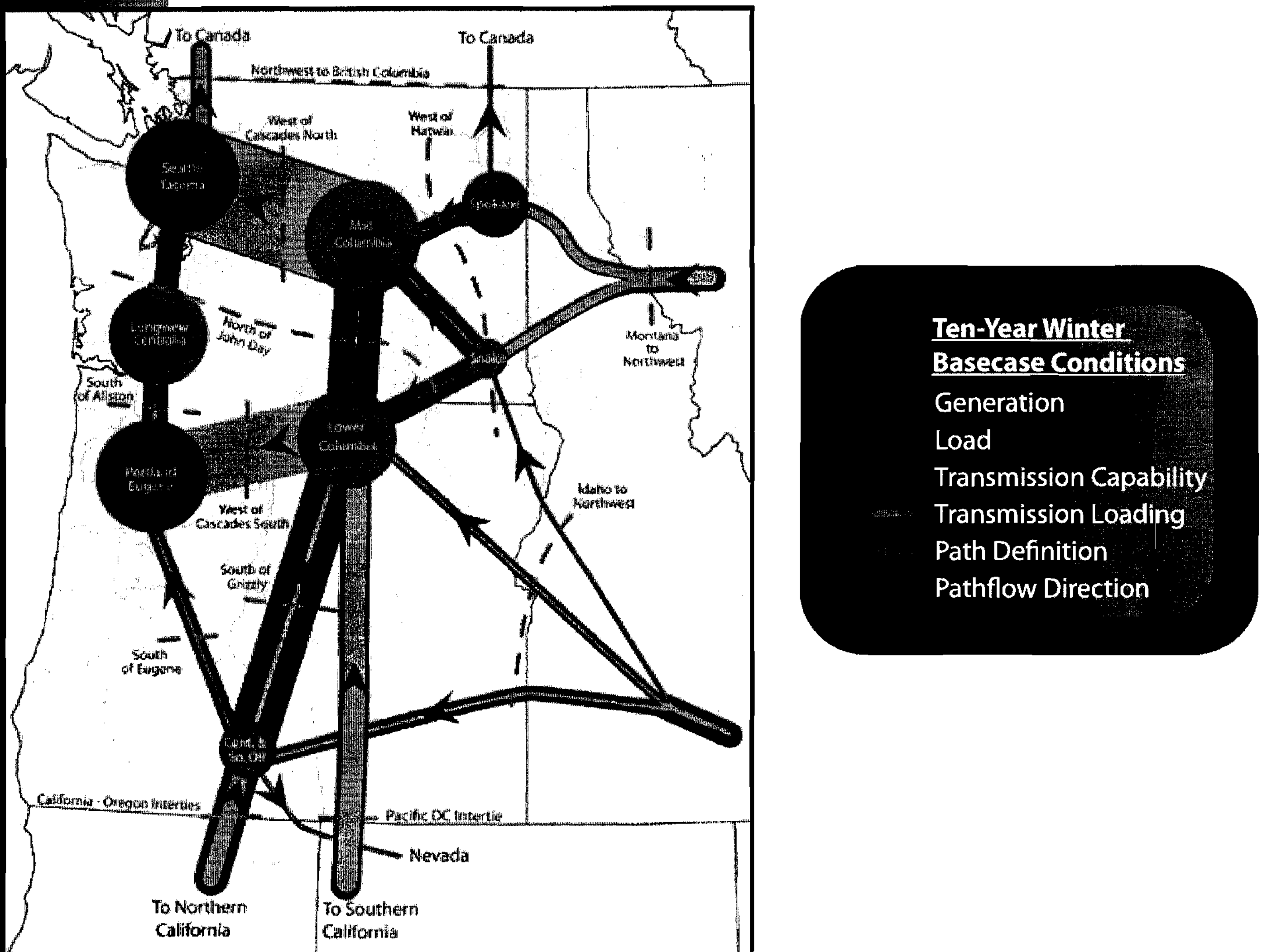


Figure 6 - Ten-Year Winter Basecase Conditions

greater than Seattle/Tacoma in the summer. The two areas had similar load levels in the winter case. This difference is due to a greater use of air conditioning. The Mid-Columbia and Lower Columbia areas have higher levels of generation in the summer as compared to the winter.

The path usage levels change significantly between summer and winter. In the summer, Canadian hydro generation exceeds the internal loads and excess generation is exported to the northwest and California. The northwest load levels are also lower in summer and there are available resources to export to the south. All of the north-to-south paths load much heavier in the summer due to these flows. The loading on the west of Cascades paths is reduced in summer due to the reduced load level in the west side. The ties to Idaho are mostly floating with little power moving on that path.

Ten-year system conditions for summer and winter are shown in Figures 6 and 7.

Special Protection System Assumptions

At the transfer levels modeled in the base cases, existing Special Protection Systems are relied on for reliable operation of the transmission system. Some of these Special Protection Systems will effectuate tripping or ramping of generation (some of which have firm transmission rights) for specified single and double line outages. This Special Protection System generation dropping relies on the use of spinning reserves to meet firm

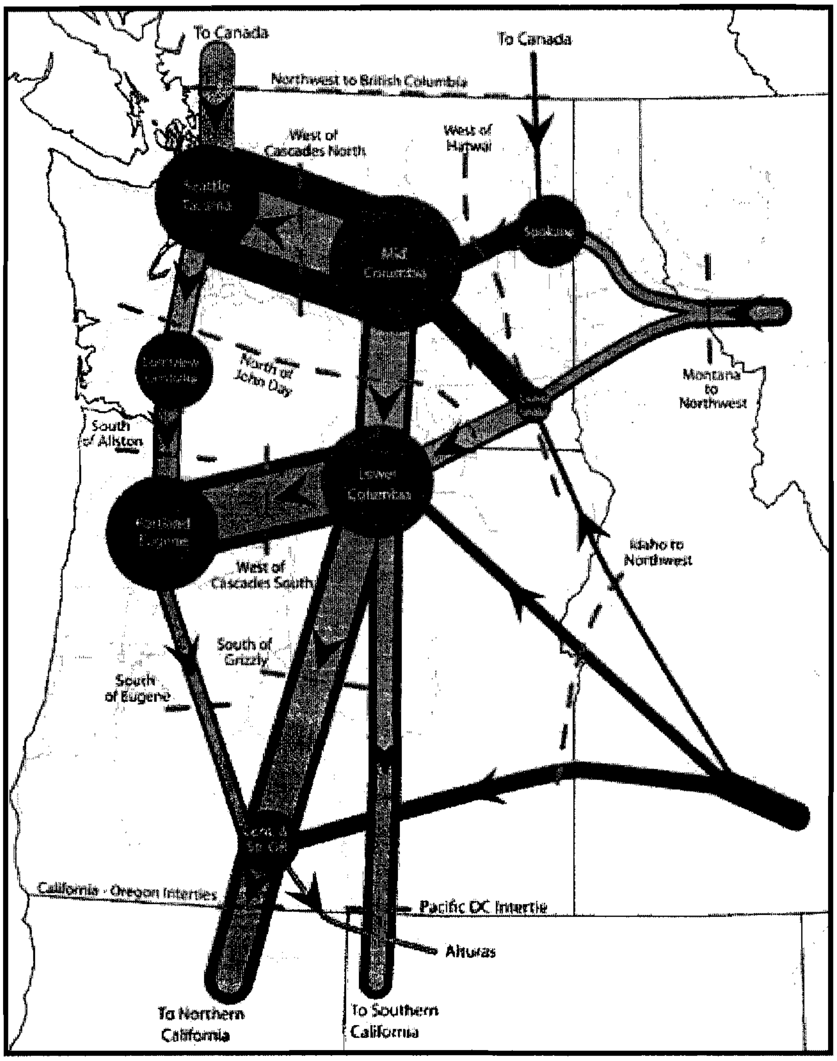


Figure 7 - Ten-Year Summer Basecase Conditions

transfer requirements (no schedule adjustments are made until the next scheduling period and no firm transfers are curtailed). If the outages are permanent, firm transfers might then need to be curtailed during the next scheduling period to meet the new operating conditions. Firm transmission service commitments are met with this use of Special Protection Systems consistent with NERC and WECC standards.

Transmission Additions Modeled

Since the last Transmission System Assessment, the following projects have been placed in service:

1. Novelty 230/115 transformer fed from the existing Monroe-Sammamish 230 kV line in the north Seattle area.
2. Covington-Berrydale 230 kV line in the south Puget Sound area
3. Rocky Reach-Andrew York 230 kV line and Andrew York 230/115 kV Substation north of Wenatchee.
4. Columbia-Quincy 115 kV line reconductoring in Central Washington.
5. Benewah-Shawnee 230 kV line in eastern Washington
6. Dry Creek-North Lewiston 230 kV line reconductoring in southeast Washington.
7. Carver-McLouglin 230 kV line in the southeast Portland area.
8. Tambark Junction-Clearview 115 kV line in the north Puget Sound area.
9. Rocky Ford 230/115 transformer in the Mid-Columbia area
10. Sherwood-Murrayhill 230 kV line in the southwest Portland area.

Figure 8: Projects Included in System Assessment

All of these transmission additions were modeled in the base cases used in this system assessment.

Since adding conceptual projects to the assessment could mask future system problems, which is the focus of the System Assessment, potential projects were not included in the base cases. The only future projects that were included in the assessment were those where the sponsoring companies had made a firm commitment to build the project within the next five years. These are typically projects that are under construction or that at least have budget approval. By including only projects that utilities are actively pursuing, the next level of needs can easily be identified and prioritized for resolution.

Table 1 lists the future projects that were included in the System Assessment. The location of these projects is shown in Figure 8. These projects are more fully described in Attachment E entitled Transmission Expansion Projects.

The North Downtown Seattle Project was not included in the basecases. Although this need was demonstrated in the 2008 System Assessment, projections of load growth in the north downtown area have decreased considerably. For that reason, the 2009 System Assessment was performed with the new load forecasts and without the North Downtown Seattle project to review the need for, and timing of, this project.

Table 1: Firm Transmission Projects included in the System Assessment Basecases

Project Name	Sponsor	Date
Olympic Peninsula Reinforcement (Satsop-Shelton 230 kV line)	Bonneville Power	2009
Libby - Troy 115 kV line rebuild	Bonneville Power	2009
Rogue SVC (South Oregon Coast)	Bonneville Power	2009
Mid Columbia Area Reinforcement (Vantage - Midway 230 kV line upgrade)	Bonneville Power	2011
Second 230/115 kV transformer at Redmond	Bonneville Power	2011
Mercer Ranch Substation connecting into the existing Ashe - Marion 500 kV line and the new McNary - John Day 500 kV line	Bonneville Power	2012
Bakeoven Series Capacitors plus other shunt caps and line upgrades (COI Upgrade)	Bonneville Power	2012
John Day - McNary 500 kV Line	Bonneville Power	2013
Big Eddy - Knight (formerly Station Z) 500 kV line looping into the existing Wautoma - Ostrander 500 kV line	Bonneville Power	2013
Central Ferry - Lower Monumental 500 kV line and connection to existing Lower Granite - Lower Monumental 500 kV lines	Bonneville Power	2013
Castle Rock - Troutdale 500 kV line (I-5 Corridor Reinforcement Project)	Bonneville Power	2015
Lower Valley Reinformcement (SE Idaho)	Bonneville Power/others	2010
Retermination of lines into Andrew York Substation	Chelan	2010
Relocation/upgrade of the McKenzie - Wenatchee Tap 115 kV line	Chelan	2012
New Rapids - South Nile 115 kV line	Douglas	2010
Columbia - Palisades 115 kV line	Douglas	2011
Douglas - Rapids 230 kV line and Rapids 230/115 kV substation	Douglas	2012
Columbia - Larson 230 kV line	Grant	2012
Hemingway - Boardman 500 kV line	Idaho Power	2013
Wine Country 230/115 kV substation (formerly Vintage Valley)	PacifiCorp	2009
Vantage - Pomona Heights 230 kV line (Yakima area)	PacifiCorp	2012
New Lookingglass Substation on the Reston - Dixonville 230 kV line (Albany area)	PacifiCorp	<2013
Parish Gap 230/115 kV substation connecting to Bethel - Fry 230 kV line (Albany area)	PacifiCorp	<2013
Keeler - Sunset 230 kV line with 230/115 kV transformers at Sunset	Portland General Electric	<2013
Springville Substation connecting to Trojan - St. Marys 230 kV line (west Portland)	Portland General Electric	<2013
South of Sedro Capacity Increase (Sedro - Horse Ranch 230 kV line)	Puget Sound Energy	2011
230/115 kV transformer at Alderton Substation in south Puget Sound area	Puget Sound Energy	2011
Thurston County Transformer Capacity (St. Claire Substation)	Puget Sound Energy	2012
Lake Tradition 230/115 kV transformer fed via Maple Valley - Sammamish 230 kV line	Puget Sound Energy	2012
North Cross Cascades Improvement (115 kV IP line upgraded to 230 kV)	Puget Sound Energy	2015
North Seattle 115 kV transmission line upgrade	Seattle City Light	2009
Boundary 230/115 kV transformer replacement	Seattle City Light/BPA	2009
Beverly Park 230-115kV transformer	Snohomish PUD	2012
Cowlitz 230 kV transformer replacement	Tacoma Power	2010
Canyon Substation (Tacoma area)	Tacoma Power	2012
Rapids - Columbia 230 kV line	undetermined	<2013

Basecase	5 year normal winter	5 year extreme winter	5 year summer	10 year normal winter	10 year extreme winter	10 year summer
Total Load	33,023	36,804	26,490	26,804	41,073	30,340
Total Generation	33,337	33,279	32,777	33,278	35,922	32,723
British Columbia - Northwest Path-flow	-1,805	-1,802	2,589	-1,805	-1,805	2,598
Montana - Northwest Pathflow	1,327	1,402	1,007	1,401	1,406	1,132
Idaho - Northwest Pathflow	664	611	61	614	607	15
PDCI Pathflow	-294	-2,248	3,101	-2,248	-2,839	1,509
COI Pathflow	-449	-2366	4608	-2370	-3636	2698
North of John Day Pathflow	1,316	-306	7,469	-315	-1,196	6,003
West of Hatwai Pathflow	548	299	377	308	645	152
South of Allston Pathflow	1,237	739	3,157	693	387	2,984
West of Cascades North Pathflow	8,579	9,546	3,591	9,494	10,641	4,558
West of Cascades South Pathflow	6,149	7,444	3,836	7,456	8,888	4,826

Table 2: Basecase Summary - numbers in MW

Several of the larger projects that were included in the base cases are discussed below:

Major Additions in the Five-Year Case

The West of McNary Area Reinforcement Project:
This Bonneville project includes two new lines; a McNary-John Day 500 kV line and a Big Eddy-Knight 500 kV line (this latter substation was previously called Station Z). The project in its entirety includes about 110 miles of new line construction and is proposed to increase the capacity of the West of McNary, West of Slatt, West of John Day and West of Cascades South transmission paths. This would provide additional transmission capability to accommodate transmission service requests in eastern Oregon that are being addressed in the Bonneville Network Open Season process. The McNary-John Day line is expected to be completed in 2012 and the Big Eddy-Knight project in 2013.

The Mercer Ranch 500/230 kV Project:
This Bonneville project would create a new 500/230 kV Substation connected into the existing Ashe-Marion and the new McNary-John Day 500 kV lines. The 230 kV side would essentially provide a collector system for generation projects (primarily wind generation). This project is expected to be completed in 2012.

The Central Ferry - Lower Monumental 500 kV line:
This Bonneville project has been proposed to integrate wind generation projects into the system. The new Central Ferry Substation is located between Little Goose and Lower Monumental Dams and includes a new forty-mile 500 kV line from Central Ferry to Lower Monumental.

Mid Columbia Area Reinforcements:
The transmission plan for the Mid Columbia area that was developed in an NTAC study team was included in the assessment. This includes the BPA Vantage/Wanapum - Midway 230 kV line reconductor and the PacifiCorp Vantage-Pomona 230 kV line. The preliminary plan for the Northern Mid C area that has been developed over the last year in the ColumbiaGrid Study Team was also included. It includes a Grant County PUD Columbia-Larson line; the Douglas PUD Douglas-Rapids 230 kV line, Rapids Substation and 230/115 kV transformer; the Rapids-Columbia 230 kV line (the sponsor of this project has not been determined at this time); a bus sectionalizing breaker at BPA's Columbia Substation; upgrades to the Chelan County PUD's McKenzie-Wenatchee Tap line and line re-terminations at Chelan's Andrew York Substation.

The Hemmingway - Boardman 500 kV Project:
This Idaho Power project includes a 300-mile 500 kV line from the Boise Idaho area to Boardman Substation. This project is intended to provide 1,300 MW of capacity in the west to east directions and 800 MW in the east-to-west direction. The proposed in-service date is 2013.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU/208

PACIFICORP
OREGON MARGINAL COST STUDY

July 24, 2009

Table 3

PacifiCorp
Oregon Marginal Cost Study
20 Year Costing Inputs and Customer Data
Marginal Unit Costs
December 2010 Dollars

Line	Description		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrigation Sch 41	Irrigation Sch 33*
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans		
			(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Billing Units																			
	Demand																			
1	Load Factors	Generation	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	67.15%	67.15%
2		Transmission	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	157.69%	157.69%
3		Feeder	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	25.93%	25.93%
4		Transformer	24.79%	24.31%	46.54%	N/A	43.28%	52.02%	53.63%	N/A	59.32%	63.22%	N/A	47.04%	N/A	42.15%	N/A	N/A	14.98%	14.98%
5	Peak Loss Factor		1.1111	1.1111	1.1111	1.0810	1.1111	1.1111	1.1111	1.0810	1.1111	1.1111	1.0810	1.0990	1.0580	1.0990	1.0580	1.0498	1.1111	1.1111
6	Peak Mw @ Generator	Generation	1,106	107	176	0	75	209	216	3	36	243	19	106	67	9	175	43	26	22
7		Transmission	1,549	112	185	0	75	206	212	3	36	242	19	106	67	3	150	39	11	9
8		Feeder	2,117	159	227	0	116	256	256	4	48	312	25	127	78	17	215	N/A	67	58
9		Transformer	2,781	304	227	N/A	127	256	256	N/A	48	312	N/A	159	N/A	17	N/A	N/A	116	100
10																				
11	Energy																			
12	Energy - Annual Mwh	@ Meter	5,435,846	582,532	430,256	1,152	431,990	672,435	922,391	18,249	206,234	1,078,480	93,931	594,746	414,743	54,345	1,175,179	404,889	136,792	118,046
13	Energy Loss Factor		1.0940	1.0940	1.0940	1.0595	1.0940	1.0940	1.0940	1.0595	1.0940	1.0940	1.0595	1.0834	1.0435	1.0834	1.0435	1.0361	1.0940	1.0940
14	Energy - Annual Mwh	@ Generator	5,946,598	637,267	470,683	1,220	472,580	735,617	1,009,059	19,335	225,612	1,179,814	99,519	644,366	432,763	58,879	1,226,240	419,485	149,645	129,138
15																				
16	Customer																			
17	Annual Customers		478,485	64,649	9,372	34	4,491	3,525	2,034	50	230	572	52	121	56	2	34	2	6,108	2,062
18	Average Customers																		2,834	756
19																				
20	Unit Costs																			
21																				
22	Generation	$ / System Peak Kw	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46	$74.46
23	Transmission	$ / System Peak Kw	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47	$75.47
24	Poles, Cond., Subst.	$ / Feeder Kw	$65.09	$68.22	$68.22	$68.22	$53.73	$53.73	$53.73	$53.73	$55.52	$55.52	$55.52	$46.61	$46.61	$23.37	$23.37	$0.00	$112.35	$129.30
25	Transformers	$ / Xfmr Kw	$1.51	$1.96	$1.96	$0.00	$1.96	$1.96	$1.96	$0.00	$1.96	$1.96	$0.00	$1.96	$0.00	$1.96	$0.00	$0.00	$1.96	$1.96
26																				
27	Energy - @ Generator																			
28	Generation	$ / Kwh	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570	$0.05570
29	Transmission	$ / Kwh	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382	$0.00382
30																				
31	Poles	$ / Cust / Year	$134.68	$150.92	$150.92	$150.92	$76.65	$76.65	$76.65	$76.65	$86.16	$86.16	$86.16	$40.33	$40.33	$0.00	$0.00	$0.00	$374.04	$463.02
32	Conductor	$ / Cust / Year	$53.94	$60.45	$60.45	$60.45	$30.71	$30.71	$30.71	$30.71	$34.50	$34.50	$34.50	$16.15	$16.15	$0.00	$0.00	$0.00	$149.80	$185.45
33	Transformers	$ / Cust / Year	$74.20	$221.25	$496.66	$0.00	$688.85	$804.03	$883.01	$0.00	$1,070.36	$1,072.63	$0.00	$1,074.16	$0.00	$1,074.16	$0.00	$0.00	$894.11	$1,045.59
34	Service Drop	$ / Cust / Year	$70.83	$91.18	$218.20	$0.00	226.92	237.05	522.35	-	522.13	522.12	-	$937.60	$0.00	$937.60	$0.00	$0.00	$0.00	$0.00
35	Meters	$ / Cust / Year	$15.54	$18.38	$38.08	$1,199.32	36.81	46.53	207.91	1,199.32	209.71	209.92	1,199.32	$262.55	$1,199.32	$262.55	$1,199.32	$42,924	$37.44	$45.09
36	Meter Reading	$ / Cust / Year	$14.00	$17.36	$17.36	$17.36	16.80	16.80	16.80	16.80	75.73	75.73	75.73	114.93	$114.93	$114.93	$114.93	$114.93	$26.74	$26.67
37	Billing & Collections	$ / Cust / Year	$32.27	$30.49	$30.49	$30.49	32.60	32.60	32.60	32.60	32.60	32.60	32.60	238.20	$238.20	$238.20	$238.20	$238.20	$33.07	$33.02
38	Uncollectables	$ / Cust / Year	$10.15	$2.73	$2.73	$2.73	25.17	25.17	25.17	25.17	180.30	180.30	180.30	1,110.75	$1,110.75	$1,110.75	$1,110.75	$1,110.75	$12.33	$9.21
39	Customer Service / Other	$ / Cust / Year	$12.82	$12.11	$12.11	$12.11	15.01	15.01	15.01	15.01	40.89	40.89	40.89	182.97	$182.97	$182.97	$182.97	$182.97	$14.72	$14.32
40	Total Commitment & Billing	$ / Cust / Year	$418.43	$604.88	$1,027.01	$1,473.38	$1,149.52	$1,284.54	$1,810.21	$1,396.26	$2,252.38	$2,254.86	$1,649.51	$3,977.64	$2,902.66	$3,921.17	$2,846.18	$44,570	$1,542.24	$1,822.38

Table 4

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
December 2010 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg	Sch 51,53,54
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 M	> 4 MW	> 4 M	Trans	Sch 41	Sch 33*	Streetlighting
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)	(sec)
	Demand Related Marginal Cost																				
1	Generation	$194,848	$82,323	$7,987	$13,086	$22	$5,551	$15,574	$16,078	$260	$2,693	$18,077	$1,442	$7,926	$4,997	$693	$12,995	$3,220	$1,924	$1,660	
2	Transmission	$227,679	$116,903	$8,457	$13,993	$23	$5,692	$15,539	$15,992	$260	$2,744	$18,237	$1,456	$8,023	$5,035	$198	$11,348	$2,949	$830	$717	
3	Distribution																				
4	Poles	$34,817	$21,222	$1,756	$2,506	$4	$752	$1,656	$1,654	$27	$339	$2,194	$176	$536	$329	$0	$0	$0	$1,664	$1,746	
5	Conductor	$113,127	$67,066	$5,389	$7,692	$12	$2,782	$6,121	$6,114	$99	$1,207	$7,838	$626	$2,409	$1,480	$0	$0	$0	$4,291	$4,373	
6	Substations	$94,077	$49,474	$3,724	$5,316	$9	$2,722	$5,989	$5,982	$97	$1,124	$7,295	$583	$2,963	$1,820	$402	$5,015	$0	$1,564	$1,350	
7	Subtotal: Pole, Cond, Subs	$242,020	$137,762	$10,870	$15,514	$25	$6,256	$13,765	$13,751	$223	$2,669	$17,327	$1,384	$5,908	$3,629	$402	$5,015	$0	$7,519	$7,468	
8	Transformers	$7,768	$4,200	$596	$445	$0	$248	$502	$502	$0	$94	$611	$0	$310	$0	$34	$0	$0	$227	$196	
9	Distribution subtotal	$249,789	$141,962	$11,465	$15,959	$25	$6,504	$14,267	$14,253	$223	$2,763	$17,938	$1,384	$6,218	$3,629	$436	$5,015	$0	$7,746	$7,664	
10																					
11	Total Demand Related	$672,316	$341,188	$27,909	$43,038	$70	$17,747	$45,380	$46,323	$743	$8,200	$54,252	$4,282	$22,167	$13,661	$1,327	$29,358	$6,169	$10,500	$10,041	
12	(Lines 1+2+9)																				
13																					
14	Energy Related Marginal Cost																				
15	Generation Energy Related	$766,240	$331,225	$35,496	$26,217	$68	$26,323	$40,974	$56,205	$1,077	$12,567	$65,716	$5,543	$35,891	$24,105	$3,280	$68,302	$23,365	$8,335	$7,193	$1,552
16	Transmission Energy Related	$52,524	$22,705	$2,433	$1,797	$5	$1,804	$2,809	$3,853	$74	$861	$4,505	$380	$2,460	$1,652	$225	$4,682	$1,602	$571	$493	$106
17	Total Energy	$818,764	$353,930	$37,929	$28,014	$73	$28,127	$43,783	$60,057	$1,151	$13,428	$70,220	$5,923	$38,351	$25,757	$3,504	$72,983	$24,967	$8,907	$7,686	$1,659
18																					
19	Customer Related Marginal Cost																				
20	Poles	$84,923	$64,440	$9,758	$1,415	$5	$344	$271	$156	$4	$20	$49	$4	$5	$3	$0	$0	$0	$2,284	$955	$6,163
21	Conductor	$31,612	$25,811	$3,907	$566	$3	$137	$109	$63	$1	$8	$20	$1	$1	$1	$0	$0	$0	$916	$382	$66
22	Transformers	$68,752	$35,505	$14,304	$4,654	$0	$3,094	$2,834	$1,796	$0	$246	$614	$0	$131	$0	$3	$0	$0	$5,461	$2,156	$111
23	Service Drops	$45,280	$33,890	$5,895	$2,045	$0	$1,019	$835	$1,063	$0	$120	$299	$0	$113	$0	$1	$0	$0	$0	$0	
24	Meters	$10,523	$7,438	$1,188	$357	$41	$165	$164	$423	$60	$48	$120	$62	$32	$67	$1	$41	$86	$229	$93	$2
25	Meter Reading	$8,321	$6,698	$1,122	$163	$1	$75	$59	$34	$1	$17	$43	$4	$14	$6	$0	$4	$0	$76	$20	$2
26	Billing & Collections	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$32
27	Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
28	Customer Service / Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
29	Total Commitment & Billing Rel.	$280,694	$200,212	$39,106	$9,624	$51	$5,162	$4,529	$3,683	$70	$519	$1,291	$85	$481	$163	$8	$97	$89	$9,136	$3,650	$6,389
30																					
31	Total Revenue @ Full MC																				
32	Generation	$961,088	$413,548	$43,483	$39,303	$90	$31,874	$56,548	$72,283	$1,337	$15,260	$83,793	$6,985	$43,817	$29,102	$3,973	$81,297	$26,585	$10,259	$8,853	$1,552
33	Transmission	$280,203	$139,608	$10,890	$15,790	$28	$7,496	$18,348	$19,845	$334	$3,605	$22,742	$1,836	$10,483	$6,687	$423	$16,030	$4,551	$1,401	$1,210	$106
34	Distribution	$480,357	$301,608	$45,330	$24,639	$33	$11,098	$18,316	$17,330	$229	$3,158	$18,920	$1,390	$6,469	$3,634	$440	$5,015	$0	$16,407	$11,158	$6,342
35	Customer - Billing	$18,233	$15,441	$1,971	$286	$1	$146	$115	$66	$2	$7	$19	$2	$29	$13	$0	$8	$0	$94	$25	$32
36	Customer - Metering	$18,842	$14,136	$2,311	$520	$41	$241	$223	$457	$61	$66	$163	$66	$46	$74	$1	$45	$86	$304	$113	$2
37	Customer - Other	$7,310	$6,133	$783	$114	$0	$67	$53	$31	$1	$9	$23	$2	$22	$10	$0	$6	$0	$42	$11	$12
38	Revenue (less Uncollectables)	$1,766,034	$890,475	$104,768	$80,651	$194	$50,923	$93,603	$110,012	$1,963	$22,105	$125,660	$10,281	$60,866	$39,520	$4,837	$102,400	$31,223	$28,508	$21,370	$8,047
39																					
40	Customer - Uncollectables	$5,740	$4,855	$177	$26	$0	$113	$89	$51	$1	$41	$103	$9	$134	$62	$2	$38	$2	$35	$7	$0
41	Total Revenue	$1,771,774	$895,330	$104,944	$80,677	$194	$51,036	$93,692	$110,063	$1,964	$22,147	$125,763	$10,291	$61,000	$39,582	$4,839	$102,438	$31,225	$28,543	$21,377	$8,047

Source: Tab 2.3 (Table 3:) '20 Year Costing Inputs and Customer Data Marginal Unit Costs'
Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'

Line 1 Generation (Table 3, Row 6) x (Table 3, Row 22)/1000
Line 2 Transmission (Table 3, Row 6) x (Table 3, Row 23)/1000
Lines 4-6 Poles, Cond., Subst. (Table 3, Row 8) x (Table 7, Row 1 - 3) x (1 + .3605) (Dist OM, Row 32)
Line 8 Transformers (Table 3, Row 9) x (Table 7, Row 7) x (1 + .3605) (Dist OM, Row 32)
Lines 15-16 Energy Related (Table 3, Row 14) x (Table 3, Row 28 - 29)
Lines 20-29 Commitment Related (Table 3, Row 17) x (Table 7, Row 13 - 27) including O&M Adders

* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 7

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs By Load Size
December 2010 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg Sch 41	Irrg Sch 33*
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans		
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Demand Related Costs ($/kW)																			
1	Poles		7.37	8.10	8.10	8.10	4.75	4.75	4.75	4.75	5.17	5.17	5.17	3.11	3.11	-	-	NA	18.27	22.21
2	Conductors		23.29	24.86	24.86	24.86	17.56	17.56	17.56	17.56	18.46	18.46	18.46	13.97	13.97	-	-	NA	47.13	55.65
3	Substation		17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	17.18	NA	17.18	17.18
4	Dist. O&M @ of Total Investment	36.05%	17.25	18.08	18.08	18.08	14.24	14.24	14.24	14.24	14.71	14.71	14.71	12.35	12.35	6.19	6.19	NA	29.77	34.26
5	Total $/ Feeder kW		$65.09	$68.22	$68.22	$68.22	$53.73	$53.73	$53.73	$53.73	$55.52	$55.52	$55.52	$46.61	$46.61	$23.37	$23.37	-	$112.35	$129.30
6																				
7	Transformers		1.11	1.44	1.44	NA	1.44	1.44	1.44	NA	1.44	1.44	NA	1.44	NA	1.44	NA	NA	1.44	1.44
8	Dist. O&M @ of Total Investment	36.05%	0.40	0.52	0.52	NA	0.52	0.52	0.52	NA	0.52	0.52	NA	0.52	NA	0.52	NA	NA	0.52	0.52
9	Total $/ Transformer kW		$1.51	$1.96	$1.96	$0.00	$1.96	$1.96	$1.96	$0.00	$1.96	$1.96	$0.00	$1.96	$0.00	$1.96	$0.00	$0.00	$1.96	$1.96
10																				
11																				
12	Commitment Related Costs ($/Customer)																			
13	Poles		98.99	110.93	110.93	110.93	56.34	56.34	56.34	56.34	63.33	63.33	63.33	29.64	29.64	-	-	NA	274.93	340.33
14	Conductors		39.65	44.43	44.43	44.43	22.57	22.57	22.57	22.57	25.36	25.36	25.36	11.87	11.87	-	-	NA	110.11	136.31
15	Transformers		54.54	162.63	365.06	NA	506.32	590.98	649.03	NA	786.74	788.41	NA	789.53	NA	789.53	NA	NA	657.19	768.53
16	Dist. O&M @ of Total Investment	36.05%	69.64	114.63	187.61	56.01	210.98	241.49	262.42	28.45	315.59	316.19	31.97	299.59	14.96	284.63	-	NA	375.72	448.89
17	Total Commitment Related		$262.82	$432.62	$708.03	$211.37	$796.21	$911.38	$990.36	$107.36	$1,191.02	$1,193.29	$120.66	$1,130.63	$56.47	$1,074.16	$0.00	$0.00	$1,417.95	$1,694.06
18																				
19	Billing Related Costs ($/Customer/Yr)																			
20	Service Drop		52.06	67.02	160.38	NA	166.79	174.24	383.94	NA	383.78	383.77	NA	689.16	NA	689.16	NA	NA	NA	NA
21	Service Drop O&M @	36.05%	18.77	24.16	57.82	NA	60.13	62.81	138.41	NA	138.35	138.35	NA	248.44	NA	248.44	NA	NA	NA	NA
22	Meter		10.90	12.89	26.70	$840.98	25.81	32.63	145.79	840.98	147.05	147.20	840.98	184.10	840.98	184.10	840.98	30,098.54	26.25	31.62
23	Meter O&M at	42.61%	4.64	5.49	11.38	358.34	11.00	13.90	62.12	358.34	62.66	62.72	358.34	78.45	358.34	78.45	358.34	12,824.99	11.19	13.47
24	Meter Reading		14.00	17.36	17.36	17.36	16.80	16.80	16.80	16.80	$75.73	$75.73	$75.73	114.93	114.93	114.93	114.93	114.93	26.74	26.67
25	Billing & Collections		32.27	30.49	30.49	30.49	32.60	32.60	32.60	32.60	$32.60	$32.60	$32.60	238.20	238.20	238.20	238.20	238.20	33.07	33.02
26	Uncollectables		10.15	2.73	2.73	2.73	25.17	25.17	25.17	25.17	$180.30	$180.30	$180.30	1,110.75	1,110.75	1,110.75	1,110.75	1,110.75	12.33	9.21
27	Customer Service / Other		12.82	12.11	12.11	12.11	15.01	15.01	15.01	15.01	40.89	40.89	40.89	182.97	182.97	182.97	182.97	182.97	14.72	14.32
28	Total Billing Related		$155.60	$172.26	$318.98	$1,262.02	$353.31	$373.16	$819.84	$1,288.90	$1,061.36	$1,061.56	$1,528.84	$2,847.01	$2,846.18	$2,847.01	$2,846.18	$44,570.39	$124.29	$128.32
29																				
30																				
31	Monthly Billing Related (Line 28 / 12)		$12.97	$14.35	$26.58	$105.17	$29.44	$31.10	$68.32	$107.41	$88.45	$88.46	$127.40	$237.25	$237.18	$237.25	$237.18	$3,714.20	$10.36	$10.69
32																				
33	Total Distribution (Comm & Billing Costs)		$418.42	$604.87	$1,027.01	$1,473.39	$1,149.52	$1,284.54	$1,810.20	$1,396.26	$2,252.38	$2,254.85	$1,649.50	$3,977.64	$2,902.65	$3,921.17	$2,846.18	$44,570.39	$1,542.24	$1,822.38
34	Line 17 + Line 28																			
35	Monthly Commitment & Bill (Line 33 / 12)		$34.87	$50.41	$85.58	$122.78	$95.79	$107.04	$150.85	$116.35	$187.70	$187.90	$137.46	$331.47	$241.89	$326.76	$237.18	$3,714.20	$128.52	$151.87

Sources: Lines
Line 1 - 2 Tab 8.1 (PC 1:) 'Hypothetical Feeder Study Results Annual Demand and Commitment Costs'
Line 3 Tab 7.1 (Dist Sub 1:) 'Distribution Substation Costs / kW'
Line 4 Sum of lines 1 to 3 multiplied by 36.05%
Tab 10.1 (Dist OM:) 'Distribution O&M Expense Loading Factor as a Percent of Dist. Plant' (for 36.05% Factor)
Line 7 Tab 9.2 (XFMR 2:) 'Transformer Demand Costs'
Line 13 - 14 Tab 8.1 (PC 1:) 'Hypothetical Feeder Study Results Annual Demand and Commitment Costs'
Line 15 Tab 9.1 (XFMR 1:) 'Transformer Commitment Costs'
Line 20 Tab 12.1 (Services 1:) 'Weighted Average Installed Service Drop Costs'
Line 22 Tab 11.1 (Meters 1:) 'Weighted Average Installed Meter Costs'
Line 23 Tab 11.5 (Meters 5:) 'Distribution Meters Expense Loading Factor' (for 42.61% Factor)
Line 24 -27 Tab 13.1 (Cust Exp Sum:) 'Summary of Customer Accounting Expense By Schedule'

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
Hypothetical Feeder Study Results
Annual Demand and Commitment Costs
December 2010 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Demand				Commitment			
			Investment $/kW		Annual $/kW		Investment $/Customer		Annual $/Customer	
Line	Load Class		Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
					(A) x 10.79%	(B) x 10.79%			(E) x 10.79%	(F) x 10.79%
1	Res - Schedule 4	(sec)	$68.33	$215.83	$7.37	$23.29	$917.45	$367.45	$98.99	$39.65
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	$75.05	$230.43	$8.10	$24.86	$1,028.06	$411.76	$110.93	$44.43
5	15+ kW	(sec)	$75.05	$230.43	$8.10	$24.86	$1,028.06	$411.76	$110.93	$44.43
6	Primary	(pri)	$75.05	$230.43	$8.10	$24.86	$1,028.06	$411.76	$110.93	$44.43
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	$44.00	$162.73	$4.75	$17.56	$522.16	$209.14	$56.34	$22.57
10	51-100 kW	(sec)	$44.00	$162.73	$4.75	$17.56	$522.16	$209.14	$56.34	$22.57
11	> 101kW	(sec)	$44.00	$162.73	$4.75	$17.56	$522.16	$209.14	$56.34	$22.57
12	Primary	(pri)	$44.00	$162.73	$4.75	$17.56	$522.16	$209.14	$56.34	$22.57
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	$47.88	$171.13	$5.17	$18.46	$586.89	$235.06	$63.33	$25.36
16	301+ kW	(sec)	$47.88	$171.13	$5.17	$18.46	$586.89	$235.06	$63.33	$25.36
17	Primary	(pri)	$47.88	$171.13	$5.17	$18.46	$586.89	$235.06	$63.33	$25.36
18										
19	LPS - Schedule 48T									
20	1 - 4 MW	(sec)	$28.78	$129.51	$3.11	$13.97	$274.70	$110.02	$29.64	$11.87
21	1 - 4 MW	(pri)	$28.78	$129.51	$3.11	$13.97	$274.70	$110.02	$29.64	$11.87
22	> 4 MW	(sec)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
23	> 4 MW	(pri)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
24										
25	Irrigation - Schedule 41	(sec)	$169.33	$436.76	$18.27	$47.13	$2,547.98	$1,020.51	$274.93	$110.11
26	Irrigation - Schedule 33*	(sec)	$205.82	$515.78	$22.21	$55.65	$3,154.15	$1,263.29	$340.33	$136.31
27										
28	The $/kW are in terms of "Feeder" kW's.									

* Schedule 33 Cost of Service results are provided for informational purposes only.

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2010 Unbundled Revenue Requirement Allocation by Rate Schedule

Line	Description	Total	(A) Residential	(B) General Service Sch 23	(C)	(D) General Service Sch 28	(E)	(F) General Service Sch 30	(G)	(H) Large Power Service Sch 48T	(I)	(J)	(K) Irrigation Sch 41	(L) Street Lgt. Sch 51, 53, 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	**Total Operating Revenues**	$915,181	$471,595	$90,790	$99	$124,369	$1,123	$73,370	$5,318	$35,927	$77,376	$17,402	$14,323	$3,489
2	**MWH**	12,680,407	5,435,846	1,012,789	1,152	2,026,816	18,249	$1,284,715	93,931	649,091	1,589,921	404,889	136,792	$26,217
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation	$961,088	$413,548	$82,786	$90	$160,704	$1,337	$99,052	$6,985	$47,790	$110,398	$26,585	$10,259	$1,552
6	Transmission	$280,203	$139,608	$26,680	$28	$45,689	$334	$26,347	$1,836	$10,906	$22,717	$4,551	$1,401	$106
7	Distribution	$480,357	$301,608	$69,969	$33	$46,745	$229	$22,078	$1,390	$6,908	$8,648	$0	$16,407	$6,342
8	Customer - Billing	$18,233	$15,441	$2,257	$1	$328	$2	$26	$2	$29	$21	$0	$94	$32
9	Customer - Metering	$18,842	$14,136	$2,830	$41	$921	$61	$229	$66	$46	$118	$86	$304	$2
10	Customer - Other	$7,310	$6,133	$897	$0	$151	$1	$33	$2	$23	$16	$0	$42	$12
11	Total	$1,766,034	$890,475	$185,419	$194	$254,537	$1,963	$147,765	$10,281	$65,702	$141,920	$31,223	$28,508	$8,047
12														
13	**Functional Revenue Requirement Allocation Factors**													
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
15	Generation	100.00%	43.03%	8.61%	0.01%	16.72%	0.14%	10.31%	0.73%	4.97%	11.49%	2.77%	1.07%	0.16%
16	Transmission	100.00%	49.82%	9.52%	0.01%	16.31%	0.12%	9.40%	0.66%	3.89%	8.11%	1.62%	0.50%	0.04%
17	Distribution	100.00%	62.79%	14.57%	0.01%	9.73%	0.05%	4.60%	0.29%	1.44%	1.80%	0.00%	3.42%	1.32%
18	Ancillary Service	100.00%	43.03%	8.61%	0.01%	16.72%	0.14%	10.31%	0.73%	4.97%	11.49%	2.77%	1.07%	0.16%
19	Customer - Billing	100.00%	84.69%	12.38%	0.01%	1.80%	0.01%	0.14%	0.01%	0.16%	0.12%	0.00%	0.51%	0.18%
20	Customer - Metering	100.00%	75.02%	15.02%	0.22%	4.89%	0.32%	1.22%	0.35%	0.25%	0.63%	0.46%	1.62%	0.01%
21	Customer - Other	100.00%	83.90%	12.27%	0.01%	2.06%	0.01%	0.45%	0.03%	0.31%	0.23%	0.01%	0.57%	0.17%
22	Embedded DSM - (mWh)	100.00%	42.87%	7.99%	0.01%	15.98%	0.14%	10.13%	0.74%	5.12%	12.54%	3.19%	1.08%	0.21%
23	Regulatory & Franchise	100.00%	51.53%	9.92%	0.01%	13.59%	0.12%	8.02%	0.58%	3.93%	8.45%	1.90%	1.57%	0.38%
24	Taxes (Revenue)													
25														
26	**Functionalized Class Revenue Requirement - (Target)**													
27	Generation	$612,171	$263,412	$52,731	$57	$102,362	$852	$63,092	$4,449	$30,440	$70,319	$16,934	$6,535	$989
28	Transmission	$75,967	$37,850	$7,233	$7	$12,387	$91	$7,143	$498	$2,957	$6,159	$1,234	$380	$29
29	Distribution	$246,801	$154,962	$35,949	$17	$24,017	$118	$11,343	$714	$3,549	$4,443	$0	$8,430	$3,258
30	Ancillary Services	$10,758	$4,629	$927	$1	$1,799	$15	$1,109	$78	$535	$1,236	$298	$115	$17
31	Customer - Billing	$11,737	$9,940	$1,453	$1	$211	$1	$17	$1	$19	$14	$0	$60	$21
32	Customer - Metering	$28,029	$21,029	$4,210	$62	$1,370	$90	$341	$99	$69	$176	$128	$453	$3
33	Customer - Other	$13,088	$10,980	$1,605	$1	$270	$1	$59	$4	$40	$29	$1	$75	$22
34	Embedded DSM - (mWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$23,859	$12,295	$2,367	$3	$3,242	$29	$1,913	$139	$937	$2,017	$454	$373	$91
36	Total	$1,022,411	$515,097	$106,475	$148	$145,658	$1,197	$85,016	$5,981	$38,546	$84,394	$19,048	$16,421	$4,430
37														
38	**Ratio of Operating Revn to Revenue Requirement-(Target)**	89.51%	91.55%	85.27%	66.81%	85.38%	93.88%	86.30%	88.91%	93.21%	91.68%	91.36%	87.23%	78.75%
39	(Line 1 / Line 36)													
40														
41	**Increase or (Decrease)**	$107,229	$43,502	$15,685	$49	$21,288	$73	$11,646	$663	$2,619	$7,018	$1,646	$2,097	$942
42	Company Proposal:	$107,229	$40,169	$9,305	$43	$18,419	$131	$11,520	$687	$5,535	$13,635	$3,469	$2,409	$1,909
43	Change:	$0	$3,333	$6,380	$6	$2,870	($57)	$127	($23)	($2,916)	($6,617)	($1,824)	($312)	($967)
44														
45	**Percent Increase (Decrease)**	11.72%	9.22%	17.28%	49.69%	17.12%	6.52%	15.87%	12.47%	7.29%	9.07%	9.46%	14.64%	26.99%