Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● mail@dvclaw.com
Suite 400
333 S.W. Taylor
Portland, OR 97204

June 27, 2007

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 PACIFIC POWER & LIGHT 2008 Transition Adjustment Mechanism
Docket No. UE 191

Dear Filing Center:

Enclosed please find one original and five copies of the Confidential Direct Testimony of Randall Falkenberg on behalf of the Industrial Customers of Northwest Utilities in the above-referenced docket. The confidential pages are provided in separate, sealed envelopes pursuant to the terms of the Protective Order in this proceeding. Also provided is a complete copy of the redacted version of the testimony.

Thank you for your assistance.

Sincerely,

<u>/s/ Christian Griffen</u>
Christian W. Griffen

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Direct Testimony of Randall Falkenberg of the Industrial Customers of Northwest Utilities upon the parties, on the service list, by causing the same to be deposited in the U.S. Mail, postage-prepaid.

Dated at Portland, Oregon, this 27th day of June, 2007.

/s/ Christian Griffen
Christian W. Griffen

CITIZENS' UTILITY BOARD OF OREGON LOWREY R BROWN JASON EISDORFER ROBERT JENKS 610 SW BROADWAY, SUITE 308 PORTLAND OR 97205 lowrey@oregoncub.org jason@oregoncub.org bob@oregoncub.org	**PACIFICORP** NATALIE HOCKEN OREGON DOCKETS DATA REQUEST RESPONSE CENTER 825 NE MULTNOMAH ST STE 800 PORTLAND OR 97232 natalie.hocken@pacificorp.com oregondockets@pacificorp.com datarequest@pacificorp.com
MCDOWELL & RACKNER PC KATHERINE A MCDOWELL 520 SW SIXTH AVE - SUITE 830 PORTLAND OR 97204 katherine@mcd-law.com	**DEPARTMENT OF JUSTICE** JASON W JONES 1162 COURT ST NE SALEM OR 97301-4096 jason.w.jones@state.or.us
OREGON PUBLIC UTILITY COMMISSION MAURY GALBRAITH PO BOX 2148 SALEM OR 97308-2148 maury.galbraith@state.or.us	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

(Confidential Information Removed)

June 27, 2007

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 requirement, cost of service, and rate design.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit ICNU/101 attached to my testimony.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. My testimony addresses issues related to PacifiCorp's requested rate increase and the Generation and Regulation Initiatives Decision Tool ("GRID") model study of normalized net variable power costs ("NVPC") for the projected test period, calendar year 2008.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend a number of adjustments to PacifiCorp's requested increase and the 2008 test year NVPC. These result in a reduction to the Company's requested Schedule 200 tariff price increase and a smaller overall increase in Oregon allocated net variable power costs. ICNU has not reviewed the revenue requirement proposals of Staff and the Citizens' Utility Board, and ICNU may adopt some of those proposals. Table 1, below, shows the dollar impact and the approximate Oregon allocation of each of my proposed adjustments. The following is a brief summary of each proposed adjustment.

Schedule 200 Price Increase

1. PacifiCorp witness Andrea Kelly understates the net variable power costs included in rates in UE 179 on Exhibit PPL/101. Ms. Kelly incorrectly assumes only \$217.5 million was included in rates in UE 179. However, in UE 179 the Company was allowed a \$10 million increase over the NVPC in rates in UE 170 (\$214.4 million) resulting in a final NPVC in rates of \$224.4 million. This error overstates the required Schedule 200 price increase.

Long-Term Contract Adjustments

2. PacifiCorp overstates the cost of generation from the Georgia-Pacific ("GP") Camas cogeneration facility. While the contract price for the resource has increased, for many years PacifiCorp has not actually made payments to GP because of contractual offset adjustments. Normally these offsets are credited to "Other Revenue" in a general rate case. However, there is no mechanism to credit these offsets in the present case. As a result, I recommend reversing the price adjustment proposed by the Company.

Modeling Adjustments

3. I have identified numerous problems with reserve modeling in GRID. The input assumptions used by the Company are demonstrably erroneous, and GRID allocates substantially more capacity to reserves than required to meet the calculated reserve requirements. I recommend three adjustments (to address these problems).

4. The VISTA hydro modeling methodology overstates the likelihood of extreme hydro conditions and overstates NVPC. I recommend use of mean hydro generation levels in place of the VISTA scenarios used in GRID to address this problem.

5. The Company computes outage rates for GRID based on actual outages for the 48 months ended December 31, 2006. Over the past decade, outage rates for PacifiCorp units have substantially increased, resulting in much higher power costs. Based on review of Root Cause Analysis ("RCA") reports I have identified numerous outages caused by poor company management, personnel errors, and factors within the control of PacifiCorp. I recommend that the

Oregon Public Utility Commission ("OPUC" or the "Commission") remove these outages from GRID.

6. [redacted] In a recent Portland General Electric Company ("PGE") case, the Commission required imputation of extrinsic value to comparable contracts. I recommend imputation of extrinsic value in this case as well.

7. GRID uses an overstated minimum capacity for Cholla 4 and understates the maximum capacity of Dave Johnson Unit 3.

8. I recommend the Commission remove the station service transaction from GRID. This one-sided adjustment is not industry standard practice. While PacifiCorp is quick to increase outage rates for this assumed loss of generation, it ignores times when generators run above their maximum rated capacity.

9. Turning off the West Valley combustion turbines ("CTs") in GRID reduces net variable power costs. This is unrealistic because in a least cost dispatch model such as GRID, a generator should not run unless it is lower in cost than other resources. Therefore, adding a generator to the model should never increase costs. It appears that this counter-intuitive result is due to problems in the GRID dispatch logic. In prior cases, the Company has agreed that uneconomic operation of CTs is a problem in GRID. Reversing this error reduces net variable power costs.

10. The planned outage schedule assumed by the Company for 2007 is overstated compared to four year historical average. Correcting this problem reduces net variable power costs.

Table 1 identifies the impact on net variable power costs associated with implementing each of my proposed adjustments.

Table 1
Summary of Recommended Adjustments
$1000

	Total Company	Est. Oregon Jurisdiction	
		SE	25.977%
		SG	25.465%
I. GRID (Net Power Cost Issues)			
1 PacifiCorp Request	$1,002,998,558		$253,330,612
A. Long Term Contract Adjustments	-$462,785		-$117,848
2 GP Camas Price	-$462,785		-$117,848
C. Modeling Adjustments	-$37,987,486		-$9,784,263
3 Extrinsic Value Call Options	-$5,274,188		-$1,370,076
4 Excecss Reserve Allocation	-14,904,026		-$3,833,464
5 CT Reserve Capability	-279,620		-$71,921
6 W-E Reserve Transfer	-2,994,481		-$770,210
7 Hydro Modeling (Vista) Adj.	-$2,420,002		-$622,449
8 Station Service	-$3,283,971		-$844,670
9 Unplanned Outages	-$4,731,022		-$1,216,866
10 Reverse DJ-3 Derate	-$2,707,076		-$696,287
11 Cholla 4 Minimum	-$271,394		-$69,805
12 Uneconomic CT Operation	-$737,694		-$189,742
13 Planned Outages	-$384,012		-$98,772
Total Power Cost Adjustments -	-$38,450,271		-$9,902,111
Allowed - Final GRID Result	$964,548,287		$243,428,501
II. Schedule 200 Price Increase			
1 PacifiCorp Request			$35,851,059
2 NPC In Rates Adjustment			-$6,909,825
3 GRID Adjustments			-$9,902,111
4 Net Increase			$19,039,122

I. SCHEDULE 200 PRICE INCREASE

Q. EXHIBIT PPL/101 PURPORTS TO JUSTIFY A $35.9 MILLION SCHEDULE 200 PRICE INCREASE. PLEASE EXPLAIN THE CALCULATION CONTAINED IN THE EXHIBIT.

A. Ms. Kelly computes the requested price increase based on allocating assumed net variable power costs of $834.4 million from UE 179 to Oregon, using the jurisdictional allocation factors from that case. However, the NVPC transition adjustment mechanism ("TAM") increase in that case was not based on such an analysis. Rather, the settlement agreement in UE 179 specified a maximum $10 million NVPC/TAM increase over the rates approved in UE 170 so long as the final GRID study in the case showed a final result (with stipulated adjustments) in excess of $834.4 million. This does not mean the $834.4 million was used directly in the determination of NVPC in rates as assumed by Ms. Kelly.

Q. EXPLAIN THE SIGNIFICANCE OF THE $834.4 MILLION FIGURE.

A. The $834.4 million figure determined whether the Company would have a NVPC/TAM increase of $10 million or less. If the final NVPC was more than $834.4 million, the Company would have an NVPC/TAM increase of no more than $10 million. If the final NVPC was less than that amount, the Company would get an increase less than $10 million.[1/] The final NVPC/TAM study in November 2006 produced a NVPC result of $872.6 million. Consequently, the Company obtained a $10 million increase in NVPC/TAM prices over and above the final NVPC "in rates" approved in UE 170. As a result, the Company

[1/] The Stipulation in UE 179, however, did not specify how the increase would have been computed in that case.

increased rates by $10 million over UE 170 levels, irrespective of any final (or even intermediate) GRID study results. See Exhibit ICNU/102. Ms. Kelly's exhibit is in error because it does not accurately reflect the actual net variable power costs included in rates in UE 179.

Q. HOW SHOULD ONE DETERMINE THE NVPC IN RATES IN UE 179?

A. It is quite simple. All one has to do is to determine the NVPC in rates from UE 170, and apply the $10 million increase allowed in UE 179. This is the only proper analysis of the NVPC in rates resulting from UE 179.

Q. HAVE YOU PERFORMED SUCH AN ANALYSIS?

A. Yes. Exhibit ICNU/103 shows the results of this calculation. Using a final NVPC/TAM from UE 170 of $796.5 million and a composite allocation factor for UE 170 power costs of approximately 26.92%, the resulting Oregon allocated NVPC in rates in UE 170 was $214.4 million. Once the $10 million increase was applied, NVPC in rates from UE 179 was $224.4 million, not $217.5 million as assumed by Ms. Kelly. This is simple mathematics.

Q. EXPLAIN THE ADJUSTMENT SHOWN ON LINE 12 OF ICNU/103.

A. The final TAM run from UE 170 showed a final NVPC figure of $798.3 million. However, Exhibit A to the Stipulation in UE 179 refers to a NVPC figure of $796.5 million as the final UE 170 NVPC. For my analysis, I use the $796.5 million figure in order to be conservative.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission use the corrected UE 179 NVPC in rates figures shown in Exhibit ICNU/103 and reduce the price increase allowed in this case by the amount shown on Table 1.

III. NET VARIABLE POWER COST ISSUES

Q. WHAT ARE "NET VARIABLE POWER COSTS" AND WHY ARE THEY IMPORTANT TO THIS PROCEEDING?

A. Net variable power costs are the variable production costs related to fuel and purchased power expenses net of power sales revenue. Net variable power costs comprise a substantial portion of the overall revenue requirement and therefore are a significant component of PacifiCorp's rates. This case deals exclusively with power costs recovered in rates and the increase needed to reflect updated power cost estimates for the 2008 rate effective period.

LONG-TERM CONTRACT MODELING IN GRID

Q. DOES GRID MODEL LONG-TERM POWER CONTRACTS?

A. Yes. The Company includes the costs and energy produced by all of its long-term contracts in GRID, along with its thermal generation resources in order to project normalized net variable power costs. I will discuss an issue related to one of PacifiCorp's long-term contracts in the following section of my testimony.

Georgia-Pacific Camas Contract

Q. HAS THE COMPANY CORRECTLY MODELED THE GEORGIA-PACIFIC ("GP") CAMAS CONTRACT?

A. No. The Company has included the unadjusted contract cost of power it received from GP, but has ignored various offsets it receives from the customer. This proposed treatment is quite "one-sided" because the Company does not actually pay anything for GP Camas power, while it seeks to increase NVPC to reflect an "artificial" contract price increase.

Q. PLEASE EXPLAIN THE PAYMENT TERMS OF THE CONTRACT.

A. While the contract is fairly complex, GP supplies steam to a generator (owned by PacifiCorp), and PacifiCorp pays a "Steam Royalty" to GP. The Steam Royalty is equal to a contract price, less certain offsets. The contract price for power changes periodically. In computing the cost of power from GP in this case, PacifiCorp has reflected only the 2008 changes to the contract price, but has ignored the impacts of the equally important contract offsets.

This is a substantial problem because the contract does not require PacifiCorp to pay for any of the power from the facility, unless it exceeds the "revenue requirement" of the project, and other conditions related to GP's average price for power are also met. However, the Company has not paid any "Steam Royalties" to the project's owners for this power since 2001, because the offsets substantially reduced the cost of power below the contract price. Because there is a "carry forward" of negative values under the contract, it appears unlikely the Company will pay GP any steam royalties for several years.

Q. WHY HASN'T THE COMPANY REFLECTED THE GP CAMAS OFFSETS?

A. The contractual offsets are included in "Other Revenue," not NVPC. These are base rate items that are not reflected in the Company's proposed NVPC/TAM price increase. As a result, the Company is reflecting one side of the GP Camas contract (the contract price increase) while ignoring the other side (the offsets that render the price increase moot). To address this issue, I recommend the

Commission not allow any updates to the GP Camas contract price unless the Company actually has to pay the increased cost.

MODELING ADJUSTMENTS

Regulating Margin/Reserve Requirements

Q. DO YOU AGREE WITH PACIFICORP'S MODELING OF REGULATING MARGIN AND RESERVE REQUIREMENTS IN GRID?

A. No. I have discovered several problems that exist in the Company's modeling of regulating margin and contingency reserves in GRID. These problems are manifested as unrealistic and inefficient operation of combustion turbines and thermal resources in GRID. Ultimately, this modeling results in a very substantial increase in net variable power costs.

Q. EXPLAIN REGULATING MARGIN AND RESERVE REQUIREMENTS AS MODELED IN GRID.

A. Ostensibly, GRID is intended to model actual system operation. In operation of the system, a certain amount of reserve capacity must be on-line (or available within ten minutes) in order to provide for a cushion against unexpected generator failures and load spikes that exceed forecast. These reserve requirements impose additional costs on the system because they require more units to be brought on line to serve load and reduce the amount of energy the Company could otherwise sell off system. Because the cost impact is substantial, it is imperative that the correct assumptions are used in GRID.

Q. DISCUSS THE TYPES OF RESERVES MODELED IN GRID.

A. There are two types of reserves modeled in GRID – contingency reserves and regulating margin. Contingency reserves are intended to provide additional capacity to cover unexpected generator outages. Regulating margins protect against unexpected load variations.

According the Western Electricity Coordinating Council ("WECC") guidelines, contingency reserve requirements equal 7% of thermal capacity on line and 5% of hydro capacity. At least half of these contingency reserves must be "spinning" (i.e., immediately available from generating capacity already on line). The remainder may be "quick start" or "ready reserve" (i.e., available in ten minutes or less).

For regulating margin, there is no specific formula that specifies the requirement. Rather, the requirement is "performance based," meaning that the Company must demonstrate that it meets North American Electric Reliability Council ("NERC") standards for operating reliability.

Q. WHAT ARE THE RESERVE REQUIREMENTS MODELED IN GRID?

A. For contingency reserves, the requirements modeled in GRID mirror the WECC guideline: 7% of thermal generation and 5% for hydro. For regulating margins, the Company uses a much different approach, based on the difference in net area load from one hour to the next.[2/] Regulating margin requirements are subject to minimum and maximum amounts inputs (upper and lower bounds). The actual formula used in GRID is shown below:

- Regulating Margin = Base Amount + one of the following:
  - If system is ramping Down: Minimum {Upper Bound, Maximum [Lower Bound, (Net Area Load Hour H – Net Area Load Hour (H-1))/2]}
  - If system is ramping Up: Minimum {Upper Bound, Maximum [Lower Bound, (Net Area Load Hour (H+1) – Net Area Load Hour H)/2]}
  - If neither: maximum of absolute value of the Down or Up calculation[3/]

2/ GRID Algorith Guide at 40.
3/ Id. at 41.

Q. IS THIS HOW REGULATING MARGIN REQUIREMENTS ARE DEVELOPED IN ACTUAL PRACTICE?

A. No. As noted above, there is no specific rule or formula used to develop regulating margin requirements for PacifiCorp or any other utility. The requirement is a performance based approach, and is not a formulaic one, such as is the case with contingency reserves. However, there have been certain analyses performed that are useful in translating the performance requirement to operating practice. Exhibit ICNU/104 presents a Western Systems Coordinating Council ("WSCC") "White Paper" addressing this issue. Page 9 of this report discusses methods used to estimate regulating margin requirements. The report does not recommend anything remotely comparable to the PacifiCorp modeling approach used in GRID. The GRID methodology also differs substantially from the actual practice at the Company's real-time operations center.[4/] As a result, I am quite skeptical that the input regulating margin assumptions are an accurate portrayal of requirements.

Review of the WSCC White Papers reveals that the most obvious problem in the GRID modeling method is that it deals with *hourly load changes*, rather than expected load changes and forecast errors in the next *ten minute* period. As such, the GRID approach is overstated from the very start. It appears that the Company has confused forecast errors with scheduling of hourly load increments. However, even more serious problems related to modeling of reserves exist in GRID.

[4/] I determined this from my November 2004 technical conference with the real-time operations staff.

Q. PLEASE EXPLAIN THE MORE SERIOUS RESERVE MODELING ISSUES.

A. The determination of the proper level of regulating margin aside, GRID allocates far more capacity to reserves than required to meet the (arguably overstated) requirements. This can be determined by comparison of the GRID model reserve requirements and allocated reserve data exported from the model.

Q. PLEASE EXPLAIN.

A. Exhibit ICNU/105 shows a comparison of GRID reserve requirements (computed by the model on an hourly basis) and the reserves actually allocated to various resources to meet the requirement determined by the model. Total GRID reserve requirements amount to <u>5.9 million megawatthours</u> ("MWh").[5/] This amounts to 0.8 million MWh of ready reserve, 2.2 million MWh of regulating margin and 2.9 million MWh of spinning contingency reserves. However, GRID actually allocates <u>9.2 million MWh</u> of reserves, some <u>56% more than required</u>. This illustrates a serious problem exists in GRID. It is most likely an error in the model. However, I have not been able to isolate the problem. In any case, the model simply has too much capacity allocated to meeting its assumed reserve requirement. Until the program error can be identified and correct, the Commission should develop an interim approach to deal with the problem in this case, and direct the Company to correct this problem in its next general rate case or TAM filing.

5/ A MWh of reserve amounts to 1 MW of generation allocated to reserves for one hour. The total MWh allocated to reserves in the test year provides a good estimate of sales forgone due to meeting the reserve requirements.

Q. ARE THERE OTHER PROBLEMS RELATED TO RESERVE MODELING IN GRID?

A. Yes. GRID assumes that only 20 MW of capacity from the Gadsby and West Valley CTs can be used to meet quick start requirements. This is controlled by a model input. For ready reserve purposes, the amount of capacity that can be brought on line is the full 40 MW. This is confirmed by the Company response to OPUC data request ("DR") No. 3. As a result of this erroneous input, GRID allocates too much lower cost capacity to spinning reserve and too many units to ready reserves when the CTs are not operating. The impact of correcting this data problem is shown on Exhibit ICNU/105 and Table 1.

Q. ARE THERE ANY OTHER PROBLEMS RELATED TO RESERVE MODELING?

A. Yes. The Company has the transmission capability to transfer up to 100 MW of ready reserve from PACW to PACE. The Company actually modeled this mode of operation in GRID until recently.[6/] In this case, the Company no longer assumes this transfer capability is used for reserves, because of the large amount of ready reserve capacity now available in PACE. Instead, this capacity is now modeled as being used to facilitate firm power transfers.

Q. WHAT IS THE COST IMPACT OF THIS ASSUMPTION?

A. Based on my GRID run, using the transfer capacity for reserves reduces power costs by close to $3 million. Use of the transfer capacity for ready reserve on a

---

6/ The Company agreed to recognize this mode of operation as a result of the technical conference I attended in Portland, in November, 2004.

more selective basis could provide even more savings.[7/] As a result, I believe the model is overstating power costs.

Q. IF THE COMPANY DOES NOT ACTUALLY USE THIS CAPABILITY CURRENTLY, DOES THIS MEAN THE MODEL SHOULD NOT USE IT?

A. No. The transfer capability exists. How often it is actually used depends on operating conditions. Some days it may make sense to use the capability, while on other days it may not be. If operators forego use of this capability and fail to minimize costs, then system operation is not prudent. Alternatively, they may not need to use the capability because they do not actually try to meet the overstated reserve allocations used by GRID. In effect, the apparent benefit of using the transfer capacity for reserves instead of for firm power may be an outcome of the over-allocation of reserves in the model. In neither case should the Company ignore this mode of operation in GRID. This adjustment is shown on Table 1 and Exhibit ICNU/105.

Q HOW DO YOU RECOMMEND THE COMMISSION ADDRESS THESE PROBLEMS RELATED TO RESERVES MODELING IN GRID ?

A. I have performed GRID studies and an analysis to quantify the impact of these input issues and the cost of the excessive allocation of reserve capacity in GRID. Exhibit ICNU/105 quantifies the cost of excessive reserves, the impact of changing the CT reserve capability, and the ready reserve transfer capacity assumption. Because there may be an overlap between the input assumption corrections and the overall problem of excessive reserve allocations, I deduct the NVPC changes due to input corrections from the calculated adjustment for

7/ For example, some days it might be more economical to use the capacity for transfer of power, and on other days it would be more economical for reserves. At present this cannot be modeled in GRID, though system operators would certain have this flexibility.

excessive reserve allocations. Exhibit ICNU/105. I recommend the Commission make these adjustments to GRID reducing net power costs by the amount shown in Table 1 and Exhibit ICNU/105.

<u>VISTA Hydro Modeling</u>

Q. ARE YOU FAMILIAR WITH THE VISTA HYDRO MODELING TECHNIQUES?

A. Yes. I participated in workshops related to the VISTA modeling conducted by the Company as part of its activities in Docket No. UE 170. I have also examined this issue as part of my work in UE 179 and other recent rate cases in Utah, Washington, and Wyoming.

Q. HOW DOES VISTA DIFFER FROM THE HISTORICAL 50 WATER YEAR MODELING APPROACH?

A. VISTA does not produce traditional water year modeling. Rather, VISTA produces a set of three "exceedence" levels representing dry, wet, and median hydro conditions. This data develops the hydro generation scenarios for each resource based on historical stream flow data.

Q. WHY DID PACIFICORP ADOPT THE VISTA MODEL?

A. Mr. Widmer has testified that the hydro data available from BPA was "growing stale."[8/] During the VISTA workshops, the Company also indicated that BPA was no longer sharing supporting information. Consequently, the Company indicated it could no longer document the fifty water years of data it traditionally used in its power cost modeling.

[8/] <u>Re PacifiCorp</u>, OPUC Docket No. UE 170, PPL/600, Widmer/18. The Company contends this problem has now been addressed.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE VISTA MODELING?

A. There is a serious problem with the VISTA modeling assumptions and data. In prior cases, the Company has admitted that the historical data used for its hydro resources did not all span consistent time periods.[9/] Further, the Company assumes that generation from all of its hydro resources is perfectly correlated across river systems and throughout the year. This means that all of the hydro resources are assumed to experience their median, wet, and dry conditions simultaneously. Indeed, it is assumed that generation from all hydro resources moves in lockstep. For example, the Company assumed that if the western system hydro resources were having a "dry" year, the same would be true for the Mid-Columbia and even the eastern hydro resources. Consequently, the VISTA "dry" case assumes that all three major resource systems will experience a drought. The same is true for the "median" and "wet" hydro scenarios.

Even more problematic is the manner in which the Company constructed various scenarios. In the "dry" cases, it was assumed that every generator experienced "dry" conditions every single month of the year. The same is true for "median" and "wet" cases. In the end, this process produces highly unrealistic results and overstates the likelihood of extreme conditions, because the "dry" and "wet" scenarios will not happen for all river systems at the same time, and certainly will not all occur each month of the year.

[9/] Id. at 20-21.

Q. IS THERE EVIDENCE TO DEMONSTRATE THAT THE CORRELATION BETWEEN THE RIVER SYSTEMS IS NOT 100% AS ASSUMED BY VISTA?

A. Yes. I have analyzed the PacifiCorp Western system hydro and Mid-Columbia, based on the most recent 50-year BPA study and the 40 water years used by the Company in its most recent Washington rate case.[10/] The correlation coefficient for the BPA data was 0.2, and the result was 0.67 for the Washington case data. Neither case demonstrates perfect correlation as assumed by VISTA. Therefore, VISTA does not accurately simulate how these river systems have historically operated or how they are expected to operate.

Q. COULD YOU PROVIDE A MATHEMATICAL EXAMPLE TO ILLUSTRATE THIS PROBLEM?

A. Yes. Consider a simple game involving six throws of a pair of fair dice. One can easily compute the expected value outcome of a throw, by assuming each side of a single die would have chance of one in six of occurring. One would compute an exceedence level of 16.66% for a score of one on a single die; 33.33% for a score of two; 50% for 3; 66.66% for four; 83.33% for five; and 100% for six.

In the VISTA method, for a roll of a pair of dice, the Company assumes that the two dice (like two river systems) are perfectly correlated. This would mean an exceedence level of 16.66% to roll a pair of ones; 33.33% for a pair of twos; 50% for a pair of threes and so on. It should be fairly obvious that exceedence levels computed under the VISTA assumption are completely unrealistic. Indeed, simple probability theory shows that the chances of rolling a

10/ In the most recent Washington case the Company presented a more traditional 40 water year study instead of the wet-median-dry scenarios it relies upon in this case. I analyzed the Washington data as part of my work in this proceeding.

pair of any number is (1/6)*(1/6) or 1/36. If the river systems, like individual dice, are independent, the VISTA methodology systematically miscalculates the exceedence levels, even if we assume the underlying data is perfectly accurate.

Q. IN A HYPOTHETICAL GAME INVOLVING THE ROLL OF A PAIR OF DICE, WOULD THE VISTA ASSUMPTION PRODUCE AN ACCURATE RESULT?

A. In general, no. Certainly in some "games" it might produce an acceptable approximation, but only in specific instances. For example, in a game where the sum of the two scores is added for six rolls of the dice, the VISTA assumption would produce a result with the same expected value as a proper analysis. Based on my analysis, the VISTA assumption may produce the correct expected value of hydro generation for this reason. It does not provide an accurate modeling of the shape of the hydro distribution, which is important in modeling of power costs.

In a game where one computes the product of the outcomes for six rolls of the dice (as in the PacifiCorp methodology for computing the joint exceedence levels), the VISTA assumption will seriously overstate the expected value of the total score. Exhibit ICNU/106 shows examples illustrating this point.

Q. WHAT IS THE FUNDAMENTAL PROBLEM WITH THE VISTA MODEL?

A. The most substantial problem is that VISTA overstates the likelihood of extreme events, whether they be drought or flood conditions. Returning to the dice example, the probability of a pair of ones (or a pair of sixes) is only 1 in 36. In VISTA it is assumed the probability is 1 in 6. This means that VISTA would be overstating the probability of an extreme event (in this case, the roll of a pair of ones or sixes). However, VISTA ignores the many more likely scenarios where the two dice have different face values (e.g., a one and a six).

Q. DO YOU HAVE ANY EVIDENCE THAT DEMONSTRATES VISTA OVERSTATES THE LIKELIHOOD OF EXTREME EVENTS?

A. Yes. Exhibit ICNU/107 shows a comparison of the VISTA exceedence levels for the wet, median, and dry cases and comparable figures based on the 40 water year study used in the most recent Washington case. The Company designed the wet, median, and dry scenarios as 25%, 50%, and 75% exceedence levels. However, when compared to the recent Washington data, it is apparent they really represent 10%, 55%, and 87.5% scenarios. As a result, GRID clearly overstates the likelihood of extreme hydro conditions. In the end, this process tends to increase power costs. I have raised this issue in prior cases, and the Company has acknowledged that the original VISTA method (which used 19 rather than 3 exceedence levels) was unrealistic. Exhibit ICNU/108. However, while the Company acknowledges that reducing the number of exceedence levels increased hydro generation, it continues to rely on the same flawed approach (albeit in a simplified form) in this case. In using the 3 state (wet, median, dry) solution, the Company has simply replaced 19 bad estimates with 3 bad estimates. This does not make the final results any more valid, however.

Q. DO YOU HAVE A SOLUTION TO THIS PROBLEM?

A. At this point, it is not possible to develop a comprehensive solution to the hydro modeling problem. To address the problem for purposes of this case, I computed the mean hydro using the inputs to the VISTA model. The mean does not depend on the shape of the distribution and, therefore, may be computed accurately. In contrast, the three exceedence levels (wet, dry, and median) are all a function of the shape of the distribution, which is unrealistic and mathematically incorrect. The results of this adjustment are shown in Table 1.

Thermal Deration Factors

Q. EXPLAIN THE SIGNIFICANCE OF THERMAL DERATION FACTORS IN GRID.

A. In GRID, thermal deration factors (also called outage rates) control the amount of generation available from thermal units. The more energy available, the lower net variable power costs. If a generator has an average outage rate of 5%, GRID assumes a thermal deration factor of 95%. This means that only 95% of the unit's capacity is available to produce energy. The remaining capacity is assumed to be permanently on outage. The Company uses a compilation of outages over the most recent forty-eight month historical period (January 2003 to December 2006) to compute the deration factors for its thermal plants. The purpose of using forty-eight months is to smooth out variations that might affect a single year.

Q. ARE THERMAL DERATION FACTORS AN IMPORTANT DRIVER IN OVERALL NET POWER COSTS?

A. Yes. PacifiCorp's thermal outage rates have increased substantially in the past ten years. Exhibit ICNU/109 shows that PacifiCorp's outage rates have increased by more than 40% compared to those used in the UE 111 test year for the same units. Also troubling is the fact that 77% of PacifiCorp's generating units have seen their outage rates increase over the past seven years.

Q. WHY DID YOU COMPARE CURRENT FIGURES TO THE 1999 OUTAGE RATES?

A. I have been analyzing PacifiCorp's outage rates since 1997, and there has been a continued upward trend to the present time. The 1999 case figures were worse than the 1997 four-year average, for example. I used 1999 figures as the base because that was prior to the Hunter outage that occurred in November 2000. The current four-year average likewise excludes the Hunter outage. Thus, this presents a fair comparison to establish meaningful trends over an extended period of time.

Q. IS THE OUTAGE RATE TREND A RESULT OF PLANT AGING?

A. No. Review of NERC figures shows that, while the national fleet of coal plants have aged substantially in recent years, outage rates have not increased. Exhibit ICNU/110.

Q. HAS THE INCREASE IN OUTAGE RATES INCREASED POWER COSTS?

A. Yes. To estimate this cost I used GRID to compute the change in net variable power costs resulting from a 10 MW change in coal capacity. I then applied this result to develop an annual average cost of the increased amount of capacity on outage. As shown in Exhibit ICNU/109, the result is about $52 million per year on a total Company basis. This results in an increase in cost to Oregon of nearly $14 million per year. An additional problem is that the increase in outage rates has also led to the need for additional thermal capacity, further increasing system costs. The increase in capacity on outage (192 MW) is equivalent to the capacity of the West Valley plant.[11/]

Q. COMPARISON OF HISTORICAL AVERAGE FIGURES DOES NOT DIRECTLY ADDRESS WHY OUTAGE RATES HAVE INCREASED. IS THERE EVIDENCE THAT THE INCREASE IN OUTAGE RATES IS DUE TO POOR OPERATION AND MANAGEMENT OF PACIFICORP'S RESOURCES?

A. Yes. To investigate the causes of these outages, I examined numerous "Root Cause Analysis" ("RCA") reports for outages that occurred at PacifiCorp's coal-fired generators during the 48-month period ending December 31, 2006. I analyzed these RCA reports and determined whether the cause of the outages was due to poor management, personnel or maintenance errors, or other avoidable causes. [redacted] PacifiCorp should be responsible for the costs of these outages, especially because they appear to be contributing to the Company's increasing outage costs. Confidential Exhibit ICNU/111 provides copies of the RCA reports referenced in this portion of my testimony.[12/]

11/ The West Valley annual revenue requirement built into rates was $16.6 million in UE 179.

12/ Permission for use of these documents was obtained in PacifiCorp's Response to ICNU DR No. 1.46.

Q. CAN YOU PROVIDE SOME EXAMPLES?

A. Yes. I focused most of my efforts on 2006 outages, as a result of my recent work in the Wyoming power cost adjustment mechanism case. In that case, I found many outages that were either poor management or personnel decisions or otherwise avoidable. I will discuss these events below.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

---

[13] ICNU/111, Falkenberg/9.

[redacted] While the outage was reported as a [redacted], in reality, it appears the problem was due to compounding maintenance errors.[14/]

[redacted]

In this case, it seems that [redacted] The Company should not be allowed to charge ratepayers for the unfavorable results of that type of decision process.

On the same day, another failure occurred at [redacted]

[redacted]

[14/] Id. at Falkenberg/16-21.
[15/] Id. at Falkenberg/22-24.
[16/] Id. at Falkenberg/28-30.
[17/] Id. at Falkenberg/31-33.

[redacted]

[redacted]

[redacted] This again appears to be an example where the Company was attempting to [redacted]

[redacted]

18/ Id. at Falkenberg/34-36.
19/ Id. at Falkenberg/37-45.

[redacted]

[redacted]

[redacted] This event was analyzed in a detailed RCA report that contained [redacted]

> [redacted]

> [redacted]

---

[20] Id. at Falkenberg/46-48.
[21] Id. at Falkenberg/49-60.
[22] Id. at Falkenberg/61-69.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Q. ALL OF THESE EVENTS OCCURRED IN 2006. WERE THERE SIMILAR CIRCUMSTANCES THAT OCCURRED PRIOR TO 2006?

A. Yes. [redacted]

[redacted]

[redacted] It might be argued that this problem was not PacifiCorp's fault. However, in UE 88, the Commission determined that the utility is in a better position than ratepayers to prevent a failure due to defective products and

---

23/ Id. at Falkenberg/67-68.
24/ Id. at Falkenberg/5-7.
25/ Id. at Falkenberg/1-3.
26/ Id. at Falkenberg/4.

should not be permitted to pass on costs related to a potential manufacturer defect.[27/]

Q. YOU INDICATED THAT THE ABOVE CASES WERE NOT REPORTED TO NERC AS DUE TO EMPLOYEE OR CONTRACTOR ERRORS. DID THE COMPANY HAVE ANY OUTAGES THAT IT DID CLASSIFY IN THAT MANNER?

A. Yes. During the period from January 1, 2003, through December 31, 2006, the Company identified [redacted] due to causes that it did report to NERC as being due to operator or personnel errors. These events resulted in [redacted] of lost energy over the 48-month period and resulted in additional costs of [redacted] million in the 2007 GRID study.

Q. IS A MISTAKE OR ERROR NECESSARILY IMPRUDENT?

A. Not always. In either case, the Company should absorb the outage cost or else it will not have the incentive to improve and operate as efficiently as possible. Owing to the declining trend in plant availabilities over the past decade, it is clear that the Company needs some motivation to improve.

Q. IS THERE PRECEDENT IN OTHER JURISDICTIONS SUPPORTING THIS TREATMENT?

A. Yes. In a recent Entergy Arkansas ("EAI") fuel case (Docket No. 05-116-U), the Arkansas Public Service Commission made a disallowance related to employee/contractor errors for outages at two EAI power plants. Also, in Docket

---

27/ The Commission stated: "We adopt TBA's finding that PGE behaved prudently with respect to the steam generator degradation. However, we disallow the steam generator costs incurred since 1991 and exclude the cost of replacing the steam generators from the imputed costs of running Trojan in the net benefits analysis. Although PGE's behavior was not faulty, PGE and the ratepayers are the only two parties to whom we can assign or impute steam-generator costs. As between those two parties, PGE is better situated to recover its costs from the manufacturer of the steam generators. Moreover, it is fair that shareholders bear some of the consequences of management investment decisions." Re PGE, OPUC Docket No. UE 88, Order No. 95-322 at 3 (Nov. 29, 1995).

No. 19142, the Georgia Commission made a similar disallowance for outages caused by employee errors.

Q. HOW DO YOU RECOMMEND THE COMMISSION ADDRESS THIS PROBLEM?

A. The Commission should remove these outage costs from the GRID study that were caused by management or personnel errors, avoidable mistakes and/or manufacturer design flaws. This results in a reduction to net variable power costs in the amount shown on Table 1.

Call Option Contracts and Extrinsic Value

Q. WHAT IS A CALL OPTION CONTRACT?

A. These are contracts that allow the Company the right to obtain additional energy on a daily basis when the market price exceeds the contract strike price. There are two basic types of call option contracts used by the Company in this case: Fixed Strike Options and Power/Gas Spread Options.

Q. CAN YOU PROVIDE AN EXAMPLE THAT ILLUSTRATES HOW SUCH CONTRACTS OPERATE?

A. Yes. In this example, I am using hypothetical numbers. For a Fixed Strike Option, pricing for energy is based on a specified strike price and a demand charge. Assume, for example, a strike price of $50/MWh and a monthly demand charge of $1.00/kW.

In this example, the demand charge is irrelevant to the decision to dispatch (i.e., obtain energy from) the contract. The "strike price" in this example would be the only variable controlling the decision to request generation from the counterparty as the demand charge must be paid whether the contract is dispatched or not. Consequently, if power prices are $50/MWh or more, it makes sense to exercise the option because it would provide energy at a cost less than or equal to the market. However, for such a contract to be an economical resource, it must provide substantially enough energy margins to offset the demand charge. For a 50 MW contract with a $1.00/kW demand charge, the total monthly demand charges amount to $50,000. Thus, the option must provide enough generation to provide energy margins of that amount or more. If not, then a conventional market purchase would be a more economical resource choice.

Q. CAN YOU PROVIDE ANOTHER EXAMPLE ILLUSTRATING A GAS/POWER SPREAD OPTION?

A. Yes, and again I am using hypothetical numbers. In such a contract, pricing for energy is based on a gas index, a heat rate, an exercise price, and a demand charge. Assume, for example, a heat rate of 10.0 MBTU/kWh and exercise price of $1/MWh, the gas price index at $5.00, and a monthly demand charge of $1.00/kW. Again, the demand charge is irrelevant to the decision to dispatch the contract. The "strike price" in this example would be computed as follows:

(Gas Price Index) times (Heat Rate) plus Exercise Price; or

5.00*10+1 = $51/MWh.

Consequently, if power prices equal or exceed $51/MWh, it makes sense to exercise the option. However, this does not mean than every time market prices equal or exceed $51/MWh, the contract would be "in the money." If gas prices where higher than $5.00, the market price would then have to exceed $51/MWh for the contract to be "in the money." As in the case of the Fixed

Strike Option Contract, the contract must be in the money enough to offset the demand charges or else a conventional purchase would be more economical.

Q. DOES PACIFICORP INCLUDE ANY SUCH CALL OPTIONS IN GRID?

A. Yes. The Company has five call option contracts included in its GRID study: [redacted] The demand charges [redacted] million in 2008) of these contracts are reflected in GRID; however, the contracts are seldom "in the money" by any substantial margin based on PacifiCorp's 2008 gas and power price assumptions. As a result, once the demand charges are included, these contracts add a "dead weight" cost to the GRID study. In fact, overall these contracts *increase* NVPC in GRID even without considering the demand charges. This suggests a logic error or some other problem in the program as this implies negative energy margin results from these options, a highly counterintuitive result. I will discuss this problem shortly. First, however, I will address the issue of the extrinsic value associated with these contracts.

Q. DESCRIBE CONFIDENTIAL EXHIBIT ICNU/112.

A. This exhibit presents the cost benefit analysis the Company performed for four of the call option contracts: [redacted]

[redacted]

Q. PLEASE EXPLAIN THIS PROBLEM USING AN EXAMPLE.

A. To illustrate the problem, I will return to the example of the call option discussed above. This option would allow PacifiCorp to purchase 50 MW per hour at a price of $50/MWh and has a demand charge of $1.00/kW. If we assume PacifiCorp's forward curve for July shows a forward price of $50/MWh, the contract could be dispatched every hour (or not), but (in either case) produce no energy margin. Considering the contract demand charges of $50,000, the "intrinsic value" or the expected value of the revenue less costs of this option is a negative $50,000. A conventional purchase contract would cost $50,000 less per month. In this example, the "intrinsic value" of the contract was a negative $50,000.

Q. WHY WOULD THE COMPANY ENTER INTO SUCH A CONTRACT?

A. To protect against price uncertainty. PacifiCorp has to be concerned that its forward curve might be wrong. Power prices are both uncertain and potentially volatile. As a result, the Company attempts to limit its exposure to the risk of higher than expected prices by purchasing the option. The value of the option exists only because of price uncertainty and volatility.

Assume, for example, that PacifiCorp has a high, medium, and low price forecast, all assumed equally likely to be correct. Assume the high forecast is \$56/MWh, the medium is \$50/MWh, and the low is \$44/MWh. Under these assumptions, the option has a 33% chance of producing an hourly energy margin of \$6/MWh,[28/] but a 67% chance of providing no energy margin at all. This produces an "expected value" hourly energy margin of 1/3 of \$6 plus 2/3 of zero, or \$2/MWh. Over a month, energy margins would be \$74,400.[29/] This is a handsome return for an option that would cost the Company only \$50,000. Consequently, the Company agrees to the contract because its "option value" (or "extrinsic value" of \$74,400) exceeds the demand charges (\$50,000). In this case, the extrinsic value of the option provides the entire justification for entering into the contract.

Q. DOES THIS MEAN THE CONTRACT IN YOUR EXAMPLE WILL ACTUALLY RETURN AN ENERGY MARGIN OF \$2/MWH?

A. No, the amount returned will be either \$6 or \$0. This is really the same thing as the fact that a roll of a fair dice will return a digit from one to six, while the expected value of the roll of a die is 3.5.[30/] The expected value of an outcome may not even be one of the possible outcomes. The expected value can only be expected to occur "on average" if there are a very large number of similar circumstances over time.

28/ \$56-\$50/MWh.
29/ \$2/MWh times 50 MW times 744 hours = \$74,400.
30/ 3.5 = 1/6(1+2+3+4+5+6).

[redacted]

Q. IS THE ABOVE DESCRIBED EVALUATION OF THIS OPTION UNREASONABLE?

A. For purposes of this example, no. The problem, however, is that in the NVPC/TAM mechanism, the Company sets power costs using a much different kind of model. GRID deals only with a single mid-point forecast of prices. In the example above, GRID would use the $50/MWh forward price, not the low, medium, and high range of price forecasts. Therefore, in GRID, this transaction would never show any benefit, even though PacifiCorp's resource selection model shows the transaction to be an economic resource. Even worse, ratepayers would be charged $50,000 for a contract from which they cannot receive a benefit.

The problem is that PacifiCorp sets rates using GRID, which treats price as a <u>deterministic</u> variable. However, it bases certain resource selection decisions on its options modeling which treats price as a <u>stochastic</u> variable. The lack of stochastic price modeling in GRID means that customers can never see all of the benefits of the call options considered in the decision to acquire these resources. In the above example, GRID would show a cost of $50,000, but would <u>not</u> show the expected value benefit of $74,400. Instead, in GRID the option value is nothing more than a deadweight cost. In this example, PacifiCorp would charge customers a cost of $50,000 and have an expected shareholders benefit of $74,400. This is a very one-sided way of modeling such a contract.

Q. ICNU HAS RAISED THIS TYPE OF ISSUE IN PRIOR CASES. HAS THE COMMISSION ADDRESSED THIS ISSUE PREVIOUSLY?

A. Yes. In UE 180, the Commission agreed that adjustments were warranted for two quite comparable PGE gas/power spread option contracts:

> We agree that the costs of the contracts should be included in PGE's test year power costs. The contracts assure supply for peak loads and emergency events, and therefore provide service to customers. For this reason, we include both contracts in rates. However, even though we reject an overall extrinsic value adjustment for PGE's resources, *we believe the extrinsic value of these two contracts should be recognized in test year power costs.* The Super Peak and Cold Snap contracts can be distinguished from the Company's other resources because they do not dispatch at all in the MONET run used to estimate test year power costs. Without an extrinsic value adjustment, customer rates would include all of the costs, and none of the benefits of the contracts. The record contains evidence on the extrinsic value of the Super Peak contract, but not the Cold Snap contract. Therefore, we accept ICNU's alternative proposal to include the extrinsic value of the Super Peak contract in rates, and adjust PGE's proposed test year power costs by $1.4 million.[31/]

Q. IN THE PGE CASE, THE CONTRACTS IN QUESTION WERE NEVER "IN THE MONEY" IN MONET OR IN ACTUAL OPERATION. IS THIS THE CASE FOR THE PACIFICORP CONTRACTS AS WELL?

A. No. However, this is not a meaningful distinction. In the simple example discussed above, the contract was dispatched every hour of the month because the strike price ($50/MWh) was equal to the expected market price. However, the contract still produced no energy margin. In the end, the number of hours the contract is dispatched is basically irrelevant. The only real issue is whether the

---

[31/] Re PGE, OPUC Docket No. UE 180/UE 181/UE 84, Order No. Order 07-015 at 13 (Jan. 12, 2007) (emphasis added).

contract is "in the money enough" with energy margins high enough to offset the contract demand charges. [redacted] This suggests GRID is dispatching these contracts in an uneconomic manner.

Q. PLEASE EXPLAIN.

A. Confidential Exhibit ICNU/113 shows results of GRID runs and other information produced by the Company in its response to ICNU DR No. 4.2. [redacted]

In the UE 180 order, the Commission was concerned that ratepayers paid 100% of the costs of the PGE contracts, but received none of the benefits. [redacted]

[redacted]

Q. IS THIS SORT OF OUTCOME LIKELY IN ACTUAL OPERATION?

A. It certainly is possible if the strike price and market price forecasts are close. In that case, the contracts could be dispatched in error if actual prices differ from the forecast. However, in GRID this should not occur because price inputs are deterministic. As a result, I am concerned that the logic used to dispatch these contracts has a mistake in it.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission impute the extrinsic value for [redacted], as it did in UE 180 for PGE. This will prevent an inequitable situation where the ratepayers pay for the costs of these contracts and receive no benefits, while the Company stands to profit if actual prices exceed the forecast. If the Company plans to use extrinsic value in its resource selection process, then the Commission must find a way to reflect extrinsic value in customer rates. The Commission did so in UE 180, and should do so again in this case.

<u>Dave Johnson and Cholla</u>

Q. EXPLAIN YOUR PROPOSED MODIFICATIONS TO CHOLLA AND DAVE JOHNSON UNIT 3 DATA INPUTS.

A. I recommend reversing two input changes made by the Company – a 10 MW capacity decrease in the maximum capacity for Dave Johnson Unit 3 (“DJ-3”), from 230 to 220 MW, and an increase in the minimum capacity of Cholla 4 from

150 MW to 250 MW. In both cases, these changes amount to a reversal of data changes made by the Company as compared to prior cases. Review of hourly generator logs demonstrate the Company's changes are not warranted.

Q. HOW DID YOU TEST THE REASONABLENESS OF THE DJ-3 CAPACITY?

A. I reviewed the hourly logs for DJ-3 for the four-year period ended December 31, 2006. I found that there were more than 5900 hours when the unit capacity exceeded 220 MW. In 2006 alone, there were nearly 1800 hours when the capacity exceeded 220 MW. Consequently, I see no basis for this 10 MW reduction in capacity now being proposed by the Company.

Q. EXPLAIN THE CHANGE TO THE CHOLLA 4 MINIMUM CAPACITY.

A. In this case, the Company changed the minimum capacity of Cholla 4 from 150 to 250 MW due to a sodium depletion problem that can cause the minimum loading for Cholla 4 increasing from 95 MW[32/] to 250 MW in a period of sixty days following an outage. The sodium depletion problem clears up during outages and the minimum can be reset back to its lower level.

The problem with the PacifiCorp input assumption is that it assumes the "worst case scenario" occurs 100% of the time and ignores the frequency of outages at the unit. In reality, Cholla has frequent enough outages that the minimum gets reset quite often. This implies 150 MW is a much more typical minimum loading level. Further, my review of the generator logs reveals that in actual practice, the unit seldom operates in the 250 MW range. In fact, the unit

---

[32/] Though the physical minimum is 95 MW, transmission considerations require it to operate at 150 MW or more.

logs show no basis for assuming any change to the minimum capacity for the unit. Again, this data change is not well supported and should be rejected.

<u>Station Service Modeling</u>

Q. EXPLAIN STATION SERVICE MODELING IN GRID.

A. The Company proposes to include a zero revenue transaction in GRID to reflect station service requirements during plant outages. This increases NVPC.

Q. IS THIS STANDARD INDUSTRY PRACTICE?

A. No. Based on my more than twenty-five years experience in working with various production cost models, this approach is quite novel and contrary to standard industry practice.

Q. ARE THRE ANY OTHER PROBLEMS WITH THE PROPOSED STATION SERVICE ADJUSTMENT?

A. Yes. This is another example of a "one-sided" adjustment proposed by the Company. The Company has reflected situations when unit generation is reduced due to station service, but ignores the thousands of hours when generators are operating at a higher capacity than the GRID model inputs assume. Based on my analysis of the four year period ended December 31, 2006, the Company typically obtains more than 50,000 MWh per year from operation in excess of the plant maximum capacities modeled in GRID. This amounts to more than 70% of the assumed station service requirement. This can happen frequently due to cooler operating temperatures, higher fuel quality, and various other circumstances which allow generators to briefly exceed their rated capacities. In 2006 alone, there were more than 14,000 hours when individual generators had operating capacities in excess of the GRID assumed maximum capacities. The Company clearly should not ignore situations when extra power is available from its generators, if it models the minor generation losses due to station service. Ironically, I have seen cases where utilities model emergency ratings and other short-term increases in generating capacity, but I've never seen a case where station service requirements are modeled as proposed by the Company.

Q. IS THE STATION SERVICE REQUIREMENT MODELED IN GRID A SUBSTANTIAL LOSS OF GENERATION TO THE COMPANY?

A. No. The station service requirement amounts to 0.16% of total coal-fired generation for the 2006 test year. The actual coal-generation allegedly being lost is likely less than the "measurement error" for unit capacities, outage rates, and other factors inherent in GRID. There is no reason to depart from industry standard techniques to model this trivial, one-sided loss in generation. I recommend the Commission adopt the adjustment shown on Table 1 to remove the station service transaction.

Combustion Turbine Dispatch

Q. DO YOU HAVE ANY CONCERNS REGARDING MODELING OF THE CT DISPATCH IN GRID?

A. Yes. I am concerned that the simulated operation of West Valley units in GRID is uneconomic. This is most likely due to a problem in the CT dispatch logic that has existed in GRID for some time. In Wyoming Public Service Commission Docket No. 20000-ER-03-198, Mr. Widmer acknowledged that combustion turbines were dispatched incorrectly in GRID and agreed to a $1 million disallowance to address the problem.[33/] Based on my GRID studies, I have

[33/] Re PacifiCorp, Wyoming Public Service Commission Docket No. 20000-ER-03-198, Final Order at ¶ 35 a2 (Feb. 28, 2004).

determined that on net, operation of the West Valley combustion turbines *increases* NVPC for the Company by the amount shown in Table 1. This can only occur if the units in question are being dispatched uneconomically by the model. Increasing available capacity should never increase NVPC because the model does not have to dispatch a higher cost resources. I recommend the Commission disallow this amount, to remove the impact of this uneconomic generation.

Q. ARE THERE ANY OTHER PROBLEMS IN THE GRID INPUTS?

A. Yes. In several cases (including the West Valley case), the Company has used planned outage schedules for 2008 that differ from the four-year average it computed. In these cases, the Company assumed more days of planned outage for certain units than actually occurred over the four-year period. Typically, in such cases, the units in question averaged only a day to two on planned maintenance in the historical period while the Company assumed a minimum of one week of planned maintenance for the 2008 test year.

I do not dispute there might be a reasonable basis for that assumption. Certainly, it may happen that for a four year period, planned outages will not reflect normal expectations. However, it is again rather one-sided of the Company to make such adjustments *only* in cases where the historical period reflected very little time lost due to planned outages. There are undoubtedly cases in the four-year period where generators experienced abnormally long planned outages. However, the Company made no attempt to either identify such situations or make to corresponding adjustments. The value of this adjustment is shown on Table 1.

Q. WHAT IS YOUR RECOMMENDATION?

A. If the Commission adopts the West Valley adjustment discussed above, it should also reverse the planned outage adjustment. If the Commission decides against the West Valley adjustment, it need not make this adjustment because it has the effect of increasing NVPC when West Valley is present. West Valley is one of the plants for which the Company arbitrarily increased planned outages. Because of the uneconomic dispatch of these units, increasing outages paradoxically *decreases* power costs. In the end, the adjustment is a "wash" if West Valley is included in the GRID run. If nothing else, this further illustrates the problem in the West Valley dispatch logic. This adjustment is quantified on Table 1.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/101

RANDALL J. FALKENBERG QUALIFICATIONS

June 27, 2007

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

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

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

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-	FL	Florida Industrial	Fla. Power Corp.	Phase-in of coal unit, fuel

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
	EI		Power Users Group		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. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling fossil 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.

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

Date	Case	Jurisdict.	Party	Utility	Subject
12/86 613	9437/	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.
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	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost

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

Date	Case	Jurisdict.	Party	Utility	Subject
			Users' Group		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.
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	Georgia Power Co.	Integrated resource planning,

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Service Commission Staff		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.
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.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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
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

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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
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

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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
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

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
6/07	UE 188	OR	ICNU	Portland General	Wind Generator Rate Surcharge
6/07	UE 192	OR	ICNU	Portland General	Power Cost Modeling

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/102

DEVELOPMENT OF TAM ADJUSTMENT

June 27, 2007

Exhibit ICNU/102
PACIFIC POWER & LIGHT COMPANY
DEVELOPMENT OF TAM ADJUSTMENT FOR JANUARY 1, 2007
FORECAST 12 MONTHS ENDED DECEMBER 31, 2007

Line No.	Description	Sch No.	kWh	Sch 200 Proposed Revenue	Proposed TAM Adjustment Revenue	Proposed TAM Adjustment Cents\kWh
	(1)	(2)	(3)	(4)	(5)	(6) (5)/(3)
	Residential					
1	Residential	4	5,423,447,855	$207,087,160	$4,122,586	0.076
2	**Total Residential**		5,423,447,855	$207,087,160	$4,122,586	
	Commercial & Industrial					
3	Gen. Svc. < 31 kW	23	1,156,146,030	$45,282,222	$901,455	0.078
4	Gen. Svc. 31 - 200 kW	28	2,076,346,691	$79,582,330	$1,584,285	0.076
5	Gen. Svc. 201 - 999 kW	30	1,332,132,861	$49,615,915	$987,728	0.074
6	Large General Service >= 1,000 kW	48	3,116,065,292	$108,661,625	$2,163,180	0.069
7	Partial Req. Svc. >= 1,000 kW	47	208,767,290	$7,170,887	$142,754	0.069
8	Agricultural Pumping Service	41	108,189,038	$4,134,809	$82,314	0.076
9	**Total Commercial & Industrial**		7,997,647,202	$294,447,788	$5,861,716	
	Lighting					
10	Outdoor Area Lighting Service	15	11,554,534	$242,992	$4,837	0.042
11	Street Lighting Service	50	11,406,000	$199,491	$3,971	0.035
12	Street Lighting Service HPS	51	15,574,917	$430,023	$8,561	0.055
13	Street Lighting Service	52	1,827,840	$38,677	$770	0.042
14	Street Lighting Service	53	8,459,069	$76,470	$1,522	0.018
15	Recreational Field Lighting	54	836,416	$13,015	$259	0.031
16	**Total Public Street Lighting**		49,658,776	$1,000,668	$19,920	
17	**Total Sales to Ultimate Consumers**		13,470,753,833	$502,535,616	$10,004,222	
18	**Employee Discount**			($212,163)	($4,222)	
19	**Total Sales with Employee Discount**		13,470,753,833	$502,323,453	$10,000,000	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/103

CALCULATION OF NVPC IN RATES

June 27, 2007

Calculation of NVPC In Rates

Line	Account	TOTAL COMPANY UE-170	FACTOR UE-170	OREGON UE-170	UE 179 Increase $10M	CY 2008
1	Sales for Resale					
2	Total Sales for Resale	1,044,905,828	27.60%	288,349,078		355,377,432
3	Purchased Power					
4	Total Purchased Power	1,224,314,720	27.43%	335,842,604		335,217,001
5	Wheeling Expense					
6	Firm	82,820,572				
7	Non Firm	3,424,966				
8	Total Wheeling Expense	86,245,538	27.57%	23,779,699		27,981,392
9	Fuel Expense					
10	Total Fuel Expense	532,656,507	26.96%	143,610,511		245,509,651
11	Subtotal	798,310,937	26.92%	214,883,736		
12	Reconciliation Adjustment	(1,810,937)	27.30%	(494,358)		
13	Net Power Cost	796,500,000	26.92%	214,389,379	224,389,379	253,330,612
				Difference from UE-179:		28,941,233
				PacifiCorp Request		35,851,059
				Adjustment		(6,909,825)

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/104

WSCC OPERATING RESERVE WHITE PAPER

June 27, 2007

WSCC Operating Reserve White Paper

Introduction

This paper seeks to clarify Operating Reserve requirements that exist in the WSCC Minimum Operating Reliability Criteria (MORC) and NERC Operating Policy Standards. It also provides an example of how Operating Reserve is to be calculated in WSCC Control Areas. It provides examples of the state of the art methods for determining Operating Reserve Requirements. Control Areas may use other methods as long as they meet the minimum requirements established by WSCC and NERC.

Both the NERC and the WSCC define Operating Reserve as capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of Spinning Reserve and Non-spinning reserve. Differences between the two definitions are the result of recent NERC policy changes, and WSCC criteria that specifies detailed requirements on how Contingency Reserve is to be calculated.

The revisions to NERC Policy Standards in December of 1996 changed the criteria for judging control area performance. The goal of the new criteria is to ensure that long term average frequency error from the desired scheduled frequency is within an acceptable limit. NERC replaced Regulation Requirement measurements A1 (ACE cross zero every 10 minutes) and A2 (average |ACE| each 10 minutes less than L_d) with control performance standards CPS1 and CPS2.

CPS1 is a 12 month average of a compliance factor that is a function of frequency bias, clock-minute average ACE, and clock-minute average frequency error. CPS2 is a count of violations of a requirement that average |ACE| be within a limit in each clock-10-minute period of an hour. CPS2 is similar to the old A2, but is different in that the CPS2 standard is based on a control area's frequency bias setting relative to the Interconnection's total frequency bias setting. A2 was a function of hourly load change.

NERC also created a Disturbance Control Standard (DCS). They replaced B1 (ACE to zero in 10 minutes following a disturbance) and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard; ACE must return either to zero or a pre-disturbance value of ACE within 10-minutes following a reportable disturbance. Control Areas are required to report all disturbances in which ACE becomes as large as 80% of the Control Area's largest contingency. This applies to generation loss or load loss. The percent recovery (within 10 minutes) for each reportable event is used to determine a penalty. If penalized, the Control Area must carry extra reserve for 3 months equal to the percentage of reserve found to be lacking in performance calculations. WSCC further refined this Standard to clarify how a penalty is allocated in a Reserve Sharing Group.

The WSCC MORC requires that system operators must know, at all times, the amount of Operating Reserve available which can be fully activated within the next 10-minutes. That means this information must be periodically calculated and displayed. How often the update should be made is not defined. Since CPS1 is based on 1-minute averaging intervals, Control Areas are well served by re-calculating reserves available and reserve requirements every 60 seconds. This also facilitates calculating 10-minute averages for WSCC RMS "Data to be Retained for Operating Reserve" purposes. NERC requires that actual performance be calculated and reported through NERC Control Performance Standard Surveys.

In defining how the Contingency Reserve requirement is calculated, the WSCC (draft MORC revisions) specifies selection of the larger of:

> A forced outage of the largest contingency, (either the largest generator, transmission path, transformer, bus section, or monopole DC), or

5% of Control Area Demand carried by hydro and 7% of the Control Area Demand carried by thermal units.

The table below provides an overview of WSCC and NERC Operating Reserve requirements.

OPERATING RESERVE						
	WSCC				**NERC**	
Component	**Measure**	**Report**		**Component**	**Measure**	**Report**
Regulating	CPS1 & CPS2	Monthly by hour		**Regulating**	CPS1 & CPS2	Monthly by hour
		Penalty = can't supply regulation service to others				Penalty = can't supply regulation service to others
(plus) Contingency 50% spinning Greater of: Largest contingency or 5% hydro plus 7% thermal	DCS Percentage recovery within 10 minutes.	Quarterly Disturbance = lessor of: 80% of largest contingency or 300 MW. Penalty = CRA carry extra % contingency reserve for 3 months		**Contingency** 50% spinning Largest contingency	DCS Percentage recovery within 10 minutes.	Quarterly Disturbance > 80% of largest contingency Penalty = CRA carry extra % contingency reserve for 3 months
(plus) interruptible imports						
(plus) on-demand obligations						

Notice that in the WSCC portion of the table above there are additional reserve requirements for interruptible imports and on-demand obligations.

The additional reserve requirement to cover interruptible import is almost always needed; however, it is not correct to use this term at <u>all</u> times without careful modification. If the amount of reserves being carried is based upon a largest single contingency that is an intertie over which interruptible imports are being received, it would be incorrect to count the interruptible imports scheduled on that tie as a separate term in the reserve requirement. This is because the interruptible imports would be counted in the intertie schedule of the contingency. At all other times, it would be necessary to carry additional operating reserves to cover the interruptible import.

On demand obligations relate to firm contractual sales of reserve obligation(s) for which the receiver has the right to call upon with notice of ten (10) minutes or less during the hour of delivery.

NERC Operating Reserve Measurements

The new NERC Operating Policy 1 of December 3, 1996 does not require that ACE cross zero every 10 minutes. It does require that following a disturbance, Control Areas must, within 10 minutes, drive ACE back to zero or to the ACE value occurring immediately before the disturbance. Since there is still a 10-minute requirement for ACE following disturbances, the definition of Operating Reserve for contingencies hasn't changed. The requirement that ACE cross zero every 10 minutes during normal operation has been replaced with criteria based on the fact that if long term average ACE is small, then average frequency error will also be small. New measurement terms have been created that have resulted in new reporting methods. Detailed definition and examples may be found in the NERC Performance Standard Training Document in sections A, B, and C. This paper will not attempt to provide the extensive detail that exists in the NERC training document. Instead, this document will suggest a monitoring method for Control Areas to use to give the system operators a feel for how their system is performing and give them confidence that NERC requirements will be met.

The new NERC measurements are:

Control Performance Standard 1 (CPS1) measures the variability of ACE related to frequency error. A Compliance Factor (CF) is derived as a calculation of clock minute average ACE divided by -10 times the Control Area's frequency bias setting times the clock-minute average frequency error.

$$CF = [\ (ACE/-10B) * \Delta F\ ]$$

(For variable bias, the calculation is more involved. Refer to the NERC training document.) The sampling periodicity of ACE and frequency error to use in the average calculation isn't defined but it is logical that it should be done at the periodicity of the ACE calculation cycle. For CPS1 to be statistically valid, ACE should be calculated at least fifteen (15) times per minute. These sub-minute calculations are averaged on each clock-minute and compared against a specified value ε_1. The value ε_1 is a constant target one minute RMS average frequency error over a year and is established by NERC.

The sign on ACE and frequency error in the calculation of CPS1 result in a credit when a Control Area ACE is assisting frequency and a debit when it is hurting frequency. If ε_1 were-zero, a positive CF would be unacceptable control performance. Since it is non-zero, a small positive CF allows for short term relaxed control strategies. The long-term calculations determine which Control Areas hurt the interconnection. The CPS1 averages are converted to a compliance factor reported monthly to NERC through the WSCC RMS reporting procedure. The compliance factors are saved in hourly accumulations so that the monthly report will identify the hours in a day in which performance is poor.

The monthly calculated compliance factors are averaged with the 11 prior months to calculate a 12 month Control Performance Standard 1 (CPS1). A Control Area must meet the CPS1 requirement 100% of the time. It is important to provide the system operator a measurement of the Control Area performance each day of the month and allow observation of what the 12 month CPS1 might be at the end of the current month. To accomplish this it is suggested that a daily CPS1 be calculated and a CPS1 value for the current month (through the last completed day) be calculated. The partial month value could also be averaged with the last 11 months on a daily basis. These mid month calculations will forewarn the operator of possible end of the month violations.

Control Performance Standard 2 (CPS2) places a limit on the 10-minute average of |ACE|. The 10-minute average must be less than a value L_{10}. The magnitude of L_{10} is a limit derived from ε_{10} target frequency error, to insure that there is a 90% probability that long term ACE deviation will be within a target based on a ratio of the Control Area's frequency bias setting to the total interconnection frequency bias setting.

Each hour, the numbers of violations are counted. The hourly violations are stored in the respective accumulation for the month for the wall clock hour completed. At the end of the month a report is sent to NERC, through the WSCC RMS reporting procedure, that will demonstrate which hours in the month contain the most violations.

A 10-minute period may be discarded from the violation calculation if less than 5 contiguous minutes of good telemetry existed. Disturbance periods are not discarded, however.

To be in compliance a Control Area must have a compliance percentage of at least 90%.

To aid the system operator it is suggested that hourly, daily and through the current day of the month CPS2 percentage compliance calculations be made and displayed to the system operator.

Disturbance Control Standard (DCS). The standard requires that within ten minutes following a disturbance a Control Area's ACE must return to either zero or to the ACE value that existed immediately prior to the disturbance. The measurement of compliance is a percentage of recovery, Ri. For RMS purposes, the DCS is reported monthly to WSCC through your NERC Regional Performance Subcommittee representative. Quarterly, your NERC Regional Performance Subcommittee representative will report to NERC. If the average percent recovery of all reportable disturbances in the quarter is less than 100%, the Control Area must carry extra Contingency Reserve for the next quarter equal to the average percentage not recovered. The calculation only counts reportable disturbances.

A disturbance must be reported if the magnitude of ACE from the disturbance reaches 80% of the Control Area's or Reserve Sharing Group's largest single contingency. Each Regional Reliability Council can make the reporting requirement more restrictive if they desire. The definition of a reportable disturbance must be defined by each Regional Reliability Council and reported to NERC.

To aid the system dispatcher it is suggested that each time there is a reportable disturbance it should be added to a calculation of DCS that includes all reportable disturbances of the current quarter. The result should be presented to the system operator as a partial quarter result.

WSCC Modifications to the NERC Disturbance Control Standard

Reportable Disturbance Reporting Threshold -- Each control area shall include events that cause it's Area Control Error (ACE) to Change by the lessor of 300 MW or 80% of it's Most Severe Single Contingency. (Ref. NERC Control Performance Standard Training Document Section D.4.1)

Average Percent Recovery -- For each Reportable Disturbance, the control area(s) with a MW loss or participating in the response, such as through operating reserve obligations or through a Reserve Sharing Group, shall calculate an Average Percent Recovery. A copy of the control area's calculations ACE Chart, and Net Tie Deviation from Schedule chart shall be submitted to the NERC Regional Performance Subcommittee representative not later that 10 calendar days after the Reportable Disturbance. (Ref. NERC Policy 1 Section A.3.2.2.2 and NERC Control Performance Standard Training Document Section D.4.2.2)

Contingency Reserve Adjustment Factor -- The WSCC Performance Work Group (PFWG) shall determine the Contingency Reserve Adjustment Factor for each control area no later than April 20, July 20, September 20, January 20, for the previous quarter. The local PFWG representatives shall allocate the factor among control areas, according to the allocation methods. (Ref. NERC Policy 1 Section A.3.2.6)

Operating Reserve for Control areas and Reserve Sharing Groups -- Minimum Operating Reserve shall be increased by the Contingency Reserve Adjustment Factor. The WSCC Performance Work Group shall monitor the compliance of each control area and Reserve Sharing Group for carrying the minimum required Operating Reserve.

WSCC OPERATING RESERVE

The WSCC Minimum Operating Reliability Criteria (MORC), section 1.A defines the minimum operating reserve criteria to ensure reliable operation of the interconnected bulk power system.

The WSCC MORC requirement states:

The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to:

- *Supply requirements for load variations.*
- *Replace generating capacity and energy lost due to forced outages of generation or transmission equipment.*
- *Meet on-demand obligations.*
- *Replace energy lost due to curtailment of interruptible imports.*

The Control Area is the responsible entity to ensure compliance with MORC Operating Reserve requirements. The intent of the criteria is for the Control Area Operator to both continuously monitor those dynamic parameters that determine the Control Area's reserve requirements, and its actual performance in meeting these minimum requirements. MORC in section 1.A.3 requires that Control Areas calculate operating reserve available in the next 10 minutes and make the calculation known at all times.

Terminology

In establishing a standard method for calculating operating reserve it may be beneficial to define some terms not found in the WSCC Reliability Criteria Part IV:

- Control Area Demand - The control area demand is determined as the firm load inside the control area plus firm exports minus firm imports. This term was formerly called, "Load Responsibility".
- On demand rights or obligations to other entities - An agreement or contract which allows an entity to request and receive firm energy and capacity, and requires an entity to deliver firm capacity and energy within ten (10) minutes.
- Thermal generation - all non-hydro resources
- Available on-AGC generation - All generation that can be responsive to AGC within ten (10) minutes. The ramp rate, unit commitment lag time, upper and lower operating limits shall all be considered in determining the amount of available generation actually responsive within ten (10) minutes.

- Available off line generation - Generation that can be synchronized and loaded within ten (10) minutes. The ramp rate, unit commitment lag time, upper and lower operating limits shall all be considered in determining the amount of available generation actually loaded within ten (10) minutes.

- Interruptible Imports, Exports and Load - Those imports, exports and load which, by contract, can be interrupted at the discretion of the system operator. For the purpose of calculating operating reserve requirements they must be responsive (ability to interrupted) within ten (10) minutes.

- Ten (10) minute area load variation - The anticipated load variation (increase or decrease) the control area expects in the next 10 minutes. Allowance shall be made for uncertainty in forecasting the load variation. A confidence factor should be used such that the uncertainly can be limited to no more than 5% error. Another way to arrive at this confidence factor is to track the performance of the load forecast error variance. Two times the standard deviation results in a 95% expected area load variation about the mean load forecast. Errors in excess of the 5% uncertainty could be considered as a legitimate reason to use the contingency reserve portion of operating reserve. Development of NERC Policy 10 will shed more light on this subject in 1999.

- Non-AGC generator - Generation which is on-line with the ability to both increase and decrease generation level, via voice communication or governor response, and can be responsive within ten (10) minutes of the disturbance.

- Ten (10) minute schedule variations - The anticipated schedule variation (increase or decrease) in the control area's interchange within the next 10 minutes. This shall include the maximum potential variation, taking into account ramp rate limits, in dynamic schedules, both import and export.

MORC, section 1.A (NERC Policy 1.A criteria)

Operating Reserve as defined by MORC is Regulating Reserve, plus Contingency Reserve, plus additional reserve for interruptible imports, plus additional reserve for on-demand obligations. MORC defines each of these reserve components in section 1.A.1 as:

REGULATING RESERVE - Sufficient spinning reserve, immediately responsive to automatic generation control (AGC). The minimum amount required is the Regulating Reserve Requirement necessary to meet NERC's Control Performance Standard.

Each Control Area should calculate regulating reserve as the sum of the 10 minute ramping ability of the generators either on AGC control and units capable of being synchronized (and placed on AGC) and loaded to a stated capability within 10 minutes. Then subtract the algebraic sum of the expected 10 minute forecasted load change, the expected 10 minute schedule variation, and current ACE requirement to meet CPS1. CPS1 regulating requirements vary with each control area depending on the control strategy implemented. Each control area approaches adequacy of load forecasts differently. A simple method and a rigorous method are presented in the example.

EXAMPLE 1 (regulating reserve)

First calculate the magnitude and direction of the regulation requirement in the next 10 minutes. Assume the values not calculated are "given" values. For example, 10 minute forecasted load variation might be based on a percentage of daily peak method. The example provided is for an increase requirement. Refer to Fig. 4.

METHOD A: (percentage of load forecast)

Lv = ±xx% of the hourly load forecast to account for expected variations about the forecast itself,

Plus

±yy% of the hourly load forecast to account for expected error in the forecast itself.

Based on a control area's experience, xx might be ≈1% of the daily peak load forecast. For control area's that perform daily load forecasts, yy is typically 3%. For control areas that use adaptive load forecasts executed every hour, yy could average slightly less than 2% with hourly ranges of <1% to ≈5%. For this method, the expected changes during the hour are applied for all 10-minute intervals.

METHOD B: (load following method)

Lv = ±MW largest difference between the trend fit of:

last hour's actual load, this hour's and next hour's expected load

And

this hour's expected load over the next 10 minutes.

Plus

±MW band width to account for short term historical load forecast errors that will not be corrected until the next official load forecast is executed.

<u>Regulating Reserve Requirement</u> (Rm)

Lv = 10 minute forecast change in load @ 95% confidence (increase +, decrease -) …. 100 MW

Sv = 10 minute schedule variation in ramps & dynamic schedules

(Increase export +, increase import -)…......................…................................ -30 MW

f(ACE) = A function of ACE requirement to meet CPS....…..……………......…......... 10 MW

Rm = 10 minute forecasted regulation requirement (increase +, decrease -)

Rm = (Lv + Sv - f(ACE)) = (100 - 30 -10) = ………...……………............... 60 MW

Next calculate the capability of available generators on-AGC control to increase generation in the next 10 minutes.

Available Regulating Reserve (Ac)

Given:

Hc = Hydro generators on AGC control are capable of a combined ramp of 20 MW per minute.
Tc = Thermal generators on AGC control are capable of a combined ramp of 5 MW per minute.
Ss = Any acquired supplemental regulation capable of a combined ramp of 5 MW per minute.
In this example, hydro generation will be bounded by an upper capability limit of 100 MW. For the ramp rates used, the capability ceases in 5 minutes.

Ac = 10 minute AGC capability (Make this always positive, even for a "down" requirement)

Ac = (Hc MW/min +Tc MW/min + Ss MW/min)* 10 min = 100 + 50 + 50 =…. 200 MW

Now calculate the excess or deficiency in Regulating Reserve Requirement by subtracting the forecasted reserve requirement from the generator capability. If the requirement Rm is "down" change the sign on the requirement to a plus before using it in the equation below.

Regulating Reserve Compliance (Rc)

Rc = Ac - Rm = 200 MW - 60 MW = 140 MW (positive result indicates an excess)

MORC, section 1.A.1 (b)

plus **CONTINGENCY RESERVE** An amount of Spinning and Non-spinning reserve, sufficient to reduce area control error (ACE) to the NERC DCS performance requirements within ten minutes, equal to the greater of:

(1) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the Most Severe Single Contingency (at least half of which must be spinning reserve); or

(2) The sum of five percent of the Control Area Demand served by hydro generation and seven percent of the Control Area Demand served by thermal generation (at least half of which must be spinning reserve). The combined unit ramp rate of each Control Area's on-line, unloaded generating capacity must be capable of responding to the Spinning Reserve requirement of that Control Area within ten minutes.

To determine if there is sufficient reserve (Spinning and Non-spinning) capability, add the ten minute Spinning and Non-spinning reserve capability in excess of the Regulating Reserve Requirement. Then subtract either, the Most Severe Single Contingency (N-1) reserve requirement, or the sum of five percent of the hydro generation plus seven percent of thermal generation serving Control Area Demand. Never use negative Regulating Reserve Requirement to reduce the Contingency Reserve Requirement. Spinning reserve is equal to the sum of the ramping MW capability of AGC and Non-AGC on line thermal and hydro units in excess of the Regulating Reserve Requirement (MORC section 1.A.1.a). Non-spinning reserve is equal to the 10 minute available interruptible load plus the 10 minute recoverable interruptible energy exports plus the 10 minute on demand rights from other systems, plus generation off line and available in ten minutes taking into account it's ramping capability.

EXAMPLE 2 (contingency reserve) Refer to Figure 1 & 2.

GIVEN:
The on line hydro units have the capability to ramp at a weighted combined rate of 20 MW per minute but will reach their upper limit in 5 minutes.
The on line thermal units have the capability to ramp at a weighted combined rate of 10 MW per minute.
Spinning reserve includes that portion available from on-AGC generation.
The most severe single contingency is the loss of a 400 MW unit. Sc…………………………..400
Hydro generation serving firm commitments is 1000 MW.
Thermal generation serving firm commitments is 2500 MW.
Interruptible exports are 150 MW.
On demand rights are 50 MW.
Cad = Current control area Control Area Demand is 3500 MW

Spinning Reserve (Sr)
Ti = 10 minute AGC thermal unit increase capability 100
Hi = 10 minute AGC hydro unit increase capability (upper limit bounded)............................. 100
Mi = 10 minute non-AGC generator increase capability 100
Sr = (Ti + Hi + Mi) 100 + 100 + 100 = 300 spinning reserve

Non-Spinning Reserve (Nr)
Og = 10 minute off line generating resources (synchronized and loaded in ten minutes).......... 150
Re = 10 minute recoverable non-firm export 150
Dr = 10 minute on demand rights from other systems 50
Nr = (Og + Re + Dr) 150 + 150 + 50 = 350 non-spinning reserve

Total Contingency Reserve Available (Tr)
Sr = Spinning Reserve…..300
Nr = Non-Spinning Reserve…...350
Tr = Sr + Nr 300 + 350 = 650 contingency reserve

Total Operating Reserve Requirement (Rr)
Rm = 10 minute forecasted Regulating Reserve Requirement (inc. +, dec. -) …...……………..60
Plus the greater of:
Sc = most severe single contingency... 400
Pg = 5% hydro plus 7% thermal generation used to meet load requirements............... 225
Rr = Rm + the greater of Sc or Pg 60 + 400 = 460 total reserve required

Contingency Reserve Compliance for disturbance (Rd)

Rd = total reserve minus the reserves required (excess reserves +, reserve deficiency-)
Rd = Tr – Rr 650 – 460 = 190 (excess reserves)

Minimum Spinning Required (Ms)

Ms = 10 minute Regulating Reserve Requirement plus ½ the greater of the most severe single contingency on the system or 5% hydro generation plus 7% thermal generation used to meet load requirements
Ms = Rm + ½ the greater of Sc or Pg 60 + 200 = 260 minimum spinning required

Minimum Spinning Compliance (Mc)
Mc = Sr – Ms 300 – 260 = 40 (excess spinning reserves)

MORC, section 1.A.1.c

plus **ADDITIONAL RESERVE FOR INTERRUPTIBLE IMPORTS** An amount of reserve, which can be made effective within ten minutes, equal to interruptible imports.

To determine if there is sufficient reserve (spinning and non-spinning) capability to meet MORC section 1.A.1.c: subtract interruptible energy imports from excess or deficient reserves in section 1.A.1(a) and (b) requirements as calculated above.

EXAMPLE 3 (additional reserve for interruptible imports)

GIVEN:
The imports that can be interrupted by another system are 100 MW total

Interruptible Import Reserve Compliance (Ic)
Ic = reserve compliance minus interruptible energy imports.

Ii = interruptible energy imports (excess reserves +, reserve deficiency -)
Ic = Rd – Ii 190 – 100 = 90 (excess reserves)

MORC, section 1.A.1.d requirements

plus **ADDITIONAL RESERVE FOR ON_DEMAND OBLIGATIONS** An amount of reserve, which can be made effective within ten minutes, equal to on-demand obligations to other entities or Control Areas.

To determine if there is sufficient reserve (spinning and non-spinning) capability to meet MORC section 1.A.1.d: subtract on demand obligations from excess or deficient reserves in section 3.1 (a) and (b) and (c) requirements as calculated above.

EXAMPLE 4 (additional reserve for on-demand obligations)

GIVEN:
The on demand obligations that can be requested by another system are 50 MW total

<u>On Demand Obligation Reserve Compliance</u> (Dc)
Dc = Interruptible import compliance reserves minus On demand Obligations.

Oo = On demand obligation (excess reserves +, reserve deficiency -)
Dc = Ic – Oo 90 – 50 = 40 (excess reserves)

MORC, Section 1.A.3 and WSCC Reliability Management System, Section II. F.

<u>Knowledge of Operating Reserve & Data Retention Requirements</u>

Each control area shall record the available reserves and reserve requirements integrated in 10-minute increments. Data shall be retained for one year. Data to retain is:

Available Regulating Reserve (Ac),
Regulating Reserve Requirement (Rm),
Spinning Reserve (Sr),
Non-Spinning Reserve (Nr),
Total Operating Reserve Requirement (Rr),
Most Severe Single Contingency (Sc),
Control Area Demand (Cad),
Net output of control area generation.

In addition, hourly data shall be retained for:

Interruptible import (Ii),
On-demand obligations (Oo),
The minimum excess reserves (Ic & Dc), available.

MORC Section 1.A.4

<u>Restoration of Operating Reserve</u>

When a control area or reserve sharing group experiences a loss of resource(s) requiring the use of contingency reserve, the amount of contingency reserve available, Tr, may cause the total contingency reserve requirement, Sc or Pg, to become deficient. The amount of the loss due to the contingency should be deducted from the contingency reserve available and from the contingency reserve requirement. Efforts to restore adequate reserves should begin immediately. The purpose of deducting the loss from the contingency reserve requirement is two-fold. To recognize that there is less reserve available for other parties in a sharing group. And to properly deduct operating reserve requirement before computing RMS compliance.

EXAMPLE 5 (adjusting Contingency Reserve Requirement during a disturbance)

In EXAMPLE 2, Sc > Pg. Our starting point is, Rr = Rm + max(Sc or Pg) …………. 460 MW

A 400 MW thermal unit trips, it was carrying 50 MW of spinning reserves. Cg = 350 MW. The next most severe single contingency is Sc = 300 MW. The revised requirements, availabilities and compliances are shown below.

Pg = 5% of Hi (which has responded to 1100) [1000 + 100]………….… 55 MW
Plus
7% of Ti (which has responded to 2200) [2500 – 350 + 50].…….. 154 MW
Pg = 209 MW

Rr = Rm + max(Sc or Pg) ………………………………………………… 60 + 300 = 360 MW

Both regulating reserve and spinning reserve have been drawn upon. But, starting off line units and changing schedules are still occurring during the ensuing 10 minutes. This control area still needs 200 MW to meet its Control Area Demand. It will call on the interruptible export and on demand rights.

<u>Check Regulating Reserve Compliance</u> (Rc)

Ac = (Hc + Tc + Sc)*10 min = (0 + 0 + 50)*10 = 50 MW
Rc = Ac - Rm = 50 – 60 = -10 MW (regulating reserve not compliant)

<u>Check Spinning Reserve Compliance</u> (Mc)

Sr = (Ti + Hi + Mi) = (50 + 0 + 100) = 150 MW spinning reserve available

Mc = Sr – Ms = Sr – (Rm + max(Sc or Pg)) = (150 - 60 – 300) = -210 MW (spinning reserve not compliant)

<u>Check Total Operating Reserve Compliance</u> (Rd)

Nr = (Og + Re + Dr) = (150 + 0 + 0) = 150 MW non-spinning reserve available
Tr = (Sr + Nr) = (150 + 150) = 300 MW contingency reserve available

Rd = Tr – Rr = (300 – 360) = -60 MW (total operating reserve not compliant)

Does this mean there is a violation of the RMS for operating reserve? No. During the 10-minute recovery period and 60-minute reserve replenishment period, there should be the recognition that the contingency of 350 MW is going to consume the available reserves. The calculation for Total Operating Reserve Requirement (Rr) should include a deduction for the contingency.

Rr = Rm + max(Sc or Pg) – Cg = 60 + 400 – 350 = 100 MW (note that the original Sc is used)

The use of Cg is limited to no more than 60 minutes while the control area makes their obligations whole. During this time, obligations to members within a reserve-sharing group may very well be reduced. Administrative procedures to reflect this should be included as an extension of this white paper.

Summary:

This white paper clarifies the WSCC requirements for WSCC Operating Reserve, both Contingency and Regulating Reserves. It includes methods for calculating the amount available and the minimum requirements. It shows how to apply excess positive Regulating Reserves to Contingency Reserve obligations. It shows how to account for limitations in generator ramp rates and uncertainty in load forecasts. It provides methods for determining obligations up to ten minutes ahead. It includes requirements for archiving information required for DCS reporting. Pictorial representations of Operating Reserve and Operating Reserve Requirements are attached after the Glossary. An example operator's display is included to show the minimum amount of information an operator needs in order to properly manage the Control Area's resources.

It does not show how to archive information for CPS reporting. It does not show how to allocate reserves among reserve sharing groups. NERC Interconnected Operations Services Implementation Task Force (IOSITF) has identified potential Regulating Reserve requirements associated with: frequency bias obligation, inadvertent paybacks, and manual time corrections.

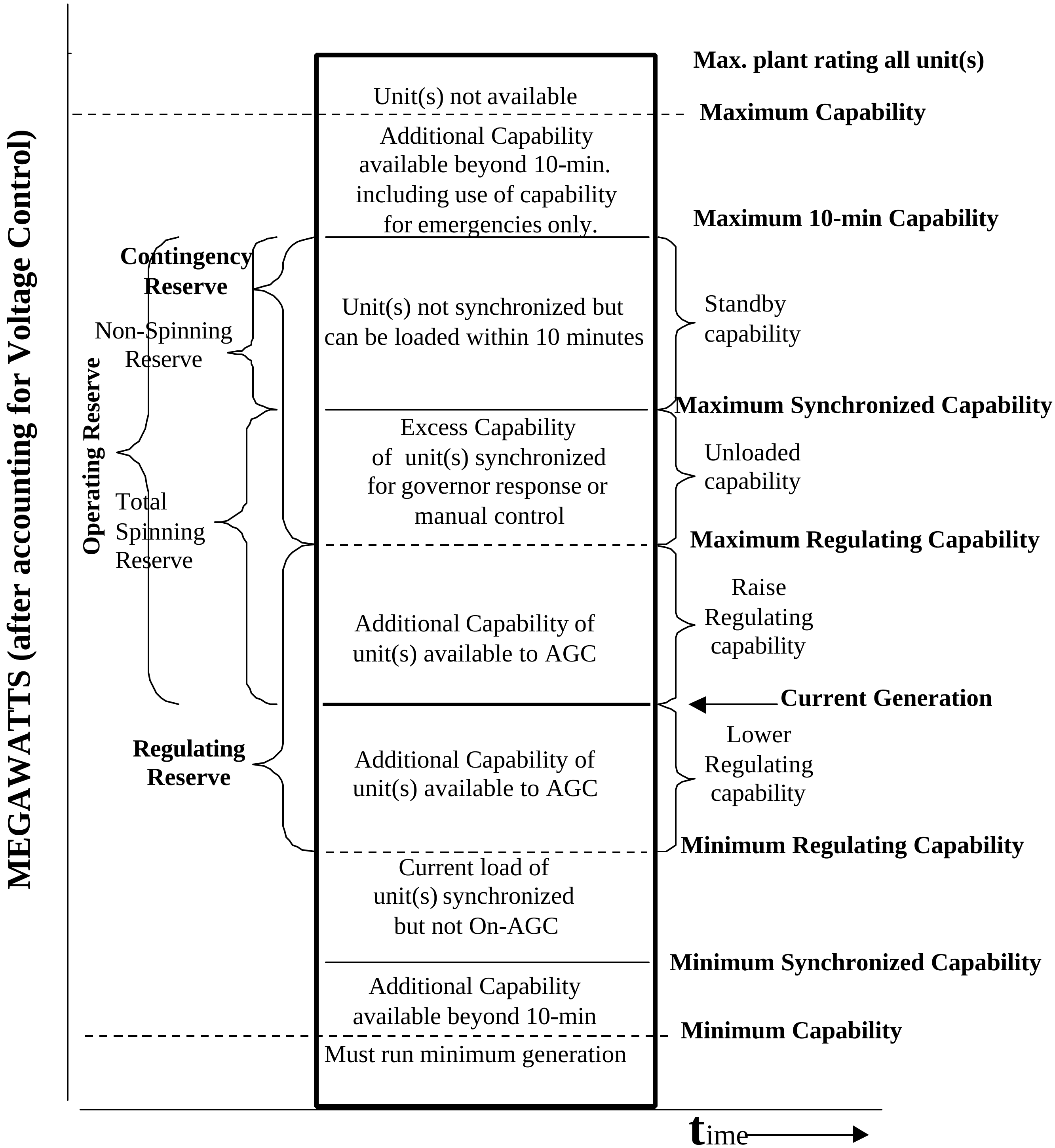
Glossary

Ac	Available Regulating Reserve
ACE	Instantaneous raw ACE
CAd	Control Area Demand
Cg	Amount of contingency currently in progress
Dc	On demand obligation reserve compliance
Dr	10 minute on demand rights from other systems
f(ACE)	Used to determine requirements for CPS
Hc	Regulating reserve from hydro generation
Hi	10 minute hydro unit AGC capacity available
Ic	Interruptible import reserve compliance
Ii	Interruptible energy imports (excess reserve +, reserve deficiency -)
Lv	Anticipated changes in area load forecast in the next 10 minutes. (increase +, decrease -)
Mc	Minimum spinning reserve compliance
Mi	10-minute non-AGC generator spinning capacity available
Ms	Minimum spinning reserve required
Nr	Non-Spinning Reserve
Og	10-minute off line generating resources

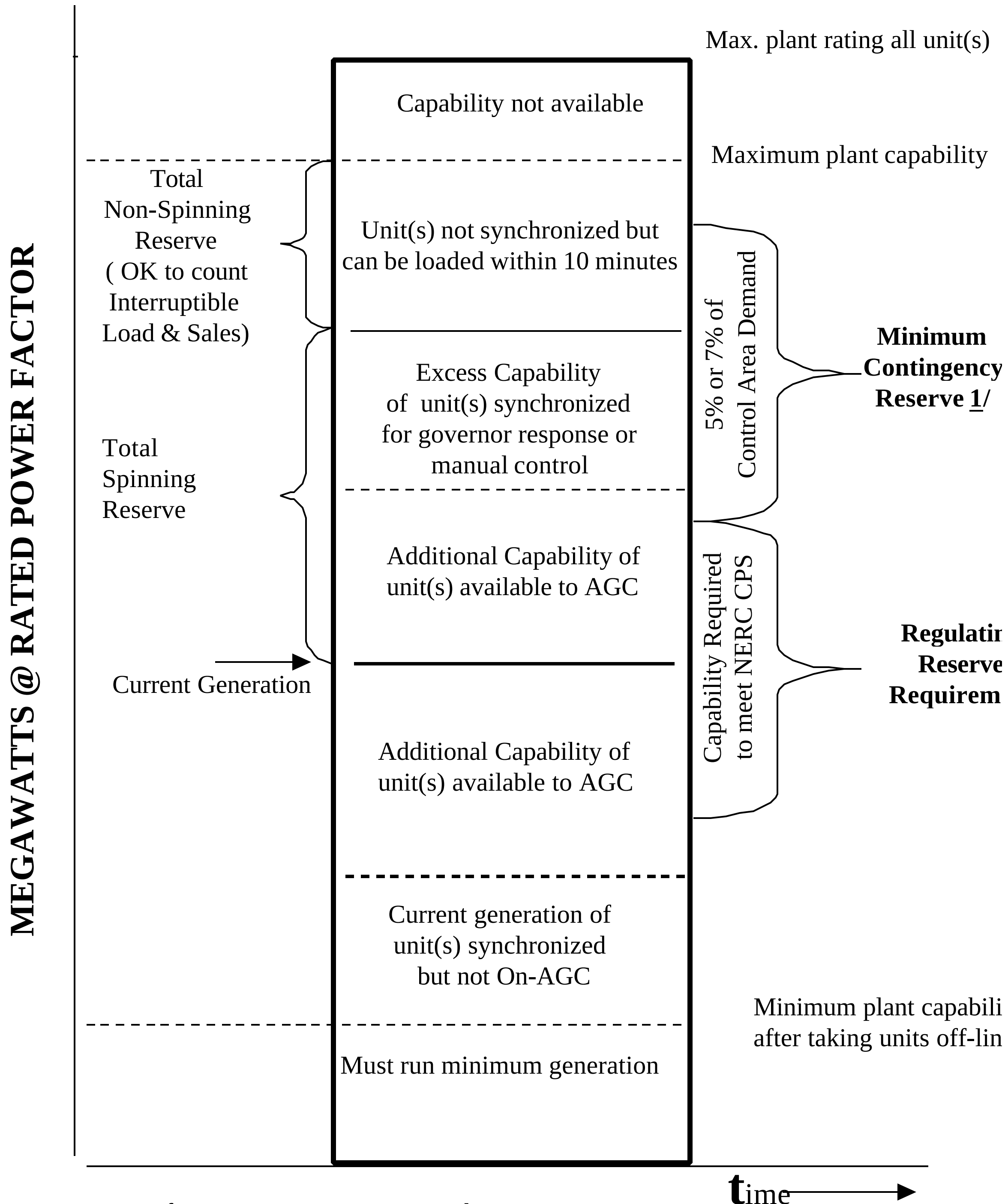
Oo	On demand obligation (excess reserve +, reserve deficiency -)
Pg	5% hydro plus 7% thermal generation used to meet Control Area Demand
Rd	Reserve Compliance for disturbance
Rc	Regulating reserve compliance (excess +, deficiency -)
Re	10-minute recoverable interruptible export
Ri	NERC defined term for DCS percent recovery for each reportable disturbance
Rm	Regulating Reserve Requirement. Regulating Reserve Obligation. Minimum Regulating Reserve
Rr	Total operating reserve requirement
Sc	Most severe single contingency
Sr	Spinning Reserve
Ss	Regulating reserve from supplemental regulating services
Sv	Anticipated changes in control area interchange schedule ramps and dynamic schedules. (More export +, more import -)
Tc	regulating reserve from thermal generation
Ti	10-minute thermal unit AGC capacity available
Tr	Total Contingency Reserve Available

Wsccreserve97.doc by Jim Dyer
Revised August 2, 1997 by WLMcReynolds
Revised September 30, 1997 by WLMcReynolds
Revised November 24, 1997 by WLMcReynolds
Revised March 12, 1998 by WLMcReynolds
Revised May 10, 1998 by WLMcReynolds
Revised July 16, 1998 by WLMcReynolds

PLANT MW CAPABILITY DIAGRAM
DEFINITION OF TERMS



WSCC OPERATING RESERVE OBLIGATION
PLANT MW CAPABILITY DIAGRAM
DEFINITION OF TERMS
(NOMINAL 10 MINUTE RESPONSE TIME)



Note 1: 50% of Contingency Reserve must be spinning.
Regulating Reserve exceeding Regulating Reserve Requirement applies toward Contingency Reserve

SYSTEM OPERATOR'S OPERATING RESERVE OBLIGATIONS & COMPLIANCE

REGULATING RESERVE REQUIREMENT (10- MIN FORECAST)			
FORECASTED LOAD CHANGE	100 MW		
DYNAMIC SCHEDULES & RAMPS	-30 MW		
ACE REQUIREMENT FOR CPS	10 MW		
REGULATING RESERVE REQUIREMENT		60 MW	
AVAILABLE REGULATING RESERVE			
HYDRO GENERATION ON AGC	10 MW/MIN		
THERMAL GENERATION ON AGC	5 MW/MIN		
SUPPLEMENTAL AGC SERVICES	5 MW/MIN		
TOTAL REGULATING RESERVE * 10 MIN		200 MW	
REGULATING RESERVE COMPLIANCE		140 MW	EXCESS
MOST SEVERE SINGLE CONTINGENCY		400 MW	
HYDRO GENERATION LOADED AT	1000 MW		
THERMAL GENERATION LOADED AT	2500 MW		
INTERRUPTIBLE LOADS	0 MW		
INTERRUPTIBLE SALES	0 MW		
CONTROL AREA DEMAND	3500 MW		
RESERVE FOR CONTROL AREA DEMAND (5% H + 7% T)		225 MW	
TOTAL CONTINGENCY RESERVE REQUIREMENT		400 MW	
HYDRO SPINNING RESERVE	100 MW		
THERMAL SPINNING RESERVE	100 MW		
NON-AGC SPINNING RESERVE	100 MW		
TOTAL SPINNING RESERVE AVAILABLE		300 MW	
OFF LINE GENERATING RESOURCES	150 MW		
INTERRUPTIBLE EXPORTS	150 MW		
ON DEMAND RIGHTS	50 MW		
TOTAL NON SPINNING RESERVE AVAILABLE		350 MW	
TOTAL CONTINGENCY RESERVE COMPLIANCE		190 MW	EXCESS
SPINNING RESERVE REQUIRED	260 MW		
TOTAL SPINNING RESERVE COMPLIANCE		40 MW	EXCESS
TOTAL INTERRUPTIBLE IMPORTS	100 MW		
INTERRUPTIBLE IMPORT RESERVE COMPLIANCE		90 MW	EXCESS
TOTAL ON DEMAND OBLIGATIONS	50 MW		
ON DEMAND OBLIGATION COMPLIANCE		40 MW	EXCESS

Unit details on other displays

Alarm if TOO LOW

Details on separate display

Details on separate display

Alarm if TOO LOW

Figure 3

TYPICAL SYSTEM LOAD re. RESERVES ANALYSIS (HOURLY SHAPING)

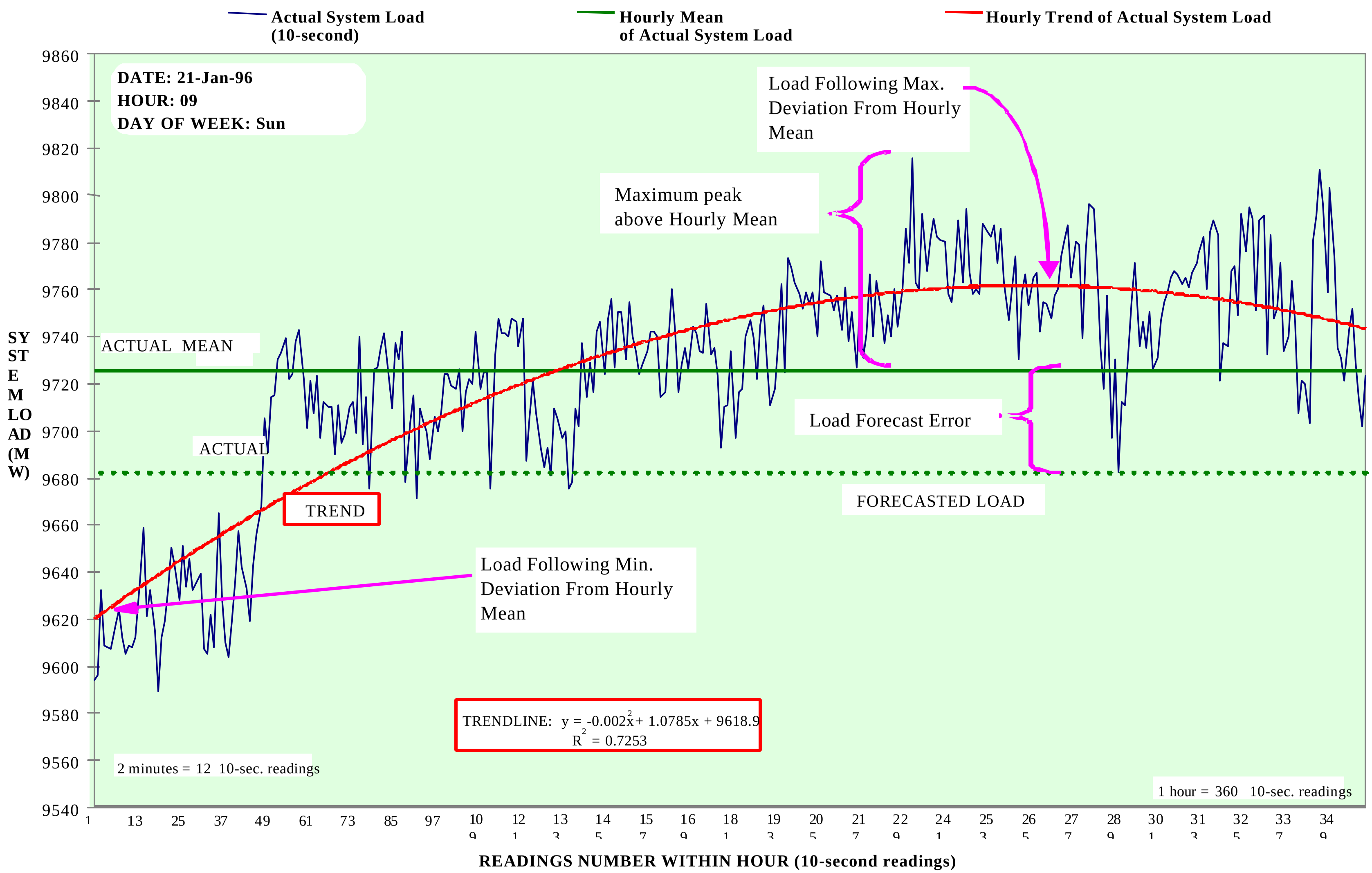


Figure 4

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/105

COMPARISON OF GRID REQUIRED AND ALLOCATED RESERVES

June 27, 2007

Exhibit ICNU/105
Comparison of GRID Required and Allocated Reserves

Computed in GRID	===========Required Reserves===========			
Control Area	**Ready**	**C. Spinning**	**Regulating**	**Total**
East	210,698	2,052,035	1,086,760	3,349,492
West	615,546	824,562	1,099,801	2,539,910
Total	826,244	2,876,597	2,186,561	5,889,403
	Contingency (Ready+Spin)		3,702,842	
	Total (Contingency+ Reg.)		5,889,403	

Dispatched by GRID	**Ready**	**Spinning**
Allocated Reserves	440,074	6,387,203
	Subtotal	6,827,278
Contractual Reserves		2,352,508
	Total	9,179,785
	Excess	3,290,383
	Excess - Ready	2,464,138
	%	56%

GRID Scenarios	**Required NPC**	**Delta**
Base Case (Median Hydro)	1,001,822,770	0
No Reserves Requirements	951,107,911	50,714,859
Total Allocated Reserves		9,179,785
Cost per mWh Allocated Reserve		5.52

Excess Allocated Reserves		**$/mWh**	**Cost**
Total mWh	3,290,383	5.52	18,178,127
Less CT 40 mW Resrve Capacity Adjustment			279,620
Less W-E Ready Reserve Transfer Adjustment			2,994,481
Net Adjustment - Excess Reserve Allocation			14,904,026

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/106

COMPARISON OF VISTA ASSUMPTIONS TO EXACT SOLUTION:

6 ROLL DICE GAMES

June 27, 2007

Exhibit ICNU/106
Comparison of VISTA Assumptions to Exact Solution: 6 Roll Dice Games

Game 1 - Sum of Six Rolls of a Pair of Dice
Exact Solution

D1->	1	2	3	4	5	6	
D2							
1	**2**	3	4	5	6	7	
2	3	**4**	5	6	7	8	
3	4	5	**6**	7	8	9	
4	5	6	7	**8**	9	10	
5	6	7	8	9	**10**	11	
6	7	8	9	10	11	**12**	
Odds	= 1/6	0.167					**Sum**
Exp. Value	4.5	5.5	6.5	7.5	8.5	9.5	**42**

Vista Approximation

Excedence	**D1**	**D2**	**Sum**	Exp. Value
16.67%	1	1	2	0.33
33.33%	2	2	4	0.67
50.00%	3	3	6	1.00
66.67%	4	4	8	1.33
83.33%	5	5	10	1.67
100.00%	6	6	12	2.00
	Expected Value 1 roll			7.00
	Expected Value 6 rolls			**42**

Game 2 - Product of Six Rolls of a Pair of Dice (Sum of Products for Six Rolls)

D1->	1	2	3	4	5	6	
D2							
1	**1**	2	3	4	5	6	
2	2	**4**	6	8	10	12	
3	3	6	**9**	12	15	18	
4	4	8	12	**16**	20	24	
5	5	10	15	20	**25**	30	
6	6	12	18	24	30	**36**	
Odds	= 1/6	0.167					Sum of Six
Exp. Value	3.5	7	10.5	14	17.5	21	**73.5**

Vista Approximation

Excedence	**D1**	**D2**	**Product**	Exp. Value
16.67%	1	1	1	0.17
33.33%	2	2	4	0.67
50.00%	3	3	9	1.50
66.67%	4	4	16	2.67
83.33%	5	5	25	4.17
100.00%	6	6	36	6.00
	Expected Value 1 roll			15.17
	Expected Value 6 rolls			**91**

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/107

HYDRO SCENARIOS

June 27, 2007

Exhibit ICNU/107
GRID WET-MED-DRY VS.
WASHINGTON CASE 25-50-75
Hydro Scenarios

Excedence Level	Mid C	Hydro	Total	WA to OR Mean Adj.	GRID Wet-Med-Dry	WA Data Wet-Med-Dry
2.50%	2,205,283	5,342,477	7,547,760	7,461,367		
5.00%	2,208,287	5,078,951	7,287,238	7,203,827		
7.50%	2,141,637	5,022,955	7,164,593	7,082,586		
10.00%	2,172,782	4,958,343	7,131,125	7,049,502	**7,045,598**	
12.50%	2,149,269	4,835,266	6,984,534	6,904,589		
15.00%	2,012,554	4,915,998	6,928,552	6,849,247		
17.50%	2,056,611	4,866,299	6,922,910	6,843,669		
20.00%	2,148,601	4,712,774	6,861,375	6,782,839		
22.50%	2,031,605	4,802,424	6,834,029	6,755,806		
25.00%	2,234,362	4,568,776	6,803,138	6,725,269		**6,725,269**
27.50%	2,088,229	4,658,671	6,746,899	6,669,674		
30.00%	1,888,255	4,804,526	6,692,780	6,616,174		
32.50%	2,093,063	4,476,115	6,569,178	6,493,986		
35.00%	2,097,847	4,439,283	6,537,130	6,462,305		
37.50%	2,043,947	4,379,851	6,423,798	6,350,271		
40.00%	1,928,633	4,422,879	6,351,512	6,278,812		
42.50%	1,992,867	4,311,871	6,304,738	6,232,574		
45.00%	1,885,457	4,387,421	6,272,879	6,201,079		
47.50%	1,969,734	4,212,212	6,181,946	6,111,187		
50.00%	1,896,003	4,272,765	6,168,768	6,098,160		**6,098,160**
52.50%	1,752,722	4,406,083	6,158,805	6,088,311		
55.00%	1,728,667	4,287,894	6,016,561	5,947,695	**5,968,921**	
57.50%	2,152,470	3,761,061	5,913,531	5,845,844		
60.00%	1,970,875	3,937,429	5,908,305	5,840,677		
62.50%	1,697,769	3,968,631	5,666,399	5,601,541		
65.00%	1,981,491	3,677,308	5,658,799	5,594,028		
67.50%	1,705,099	3,891,237	5,596,336	5,532,280		
70.00%	1,995,870	3,595,499	5,591,368	5,527,369		
72.50%	1,768,166	3,778,906	5,547,072	5,483,580		
75.00%	1,846,434	3,579,950	5,426,384	5,364,273		**5,364,273**
77.50%	1,638,538	3,641,155	5,279,694	5,219,262		
80.00%	2,046,661	3,222,771	5,269,432	5,209,118		
82.50%	1,798,346	3,432,246	5,230,593	5,170,723		
85.00%	1,648,317	3,501,816	5,150,133	5,091,184		
87.50%	1,879,002	3,157,290	5,036,291	4,978,645	**4,977,746**	
90.00%	1,739,026	3,257,133	4,996,160	4,938,973		
92.50%	1,668,717	3,305,202	4,973,920	4,916,988		
95.00%	1,700,355	3,226,921	4,927,277	4,870,879		
97.50%	1,693,607	3,176,831	4,870,438	4,814,690		
100.00%	1,847,985	2,894,185	4,742,170	4,687,891		
Mean	**1,937,629**	**4,129,235**	**6,066,864**	**5,997,422**		

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/108

DOCKET NO. UE 179:

PACIFICORP RESPONSE TO ICNU DATA REQUEST NO. 1.19

June 27, 2007

UE-179/PacifiCorp
March 24, 2006
ICNU 1st Set Data Request 1.19

ICNU Data Request 1.19

Please explain the Company's choice of hydro levels (i.e., 25-50-75, median, 5% to 95%) used in this case. To the extent that this differs from hydro levels assumed in Docket No. UE 170, please explain how and why.

1st Replacement Response to ICNU Data Request 1.19

The Company used exceedence levels wet (25), median (50) and dry (75) in this filing.

There are several reasons for using three exceedence levels versus the nineteen exceedence levels used in prior filings.

- The Company agrees with intervenors' position in this and other jurisdictions' prior rate cases, that nineteen exceedence levels placed too much emphasis on the tails which resulted in a slightly higher level of net power cost.
- Internally the Company uses three exceedence levels (wet, median, dry) in its planning activities. Due to the issue with the 19 exceedence levels, the Company adopted the approach used for planning activities.
- There is a significant reduction in model run time using three exceedence levels versus nineteen exceedence levels.

It should be noted that the use of 3 exceedence levels versus 19 resulted in a small decrease in hydro generation.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/109

COMPARISON OF OUTAGE RATES UE 111 AND UE 179

June 27, 2007

Exhibit ICNU/109
Comparison of Outage Rates UE 111 and UE 179

	=========== UE 191 =========				1999 Case	=Avg Capacity on Outage=	
	Unit ID	Current Rated Capacity	Outage Rate	PacifiCorp Share	Outage Rate	2007 Case	1999 Case
1	CHO-4	380	8.38%	100.0%	6.67%	31.8	25.3
2	COL-3	740	9.99%	10.0%	7.17%	7.4	5.3
3	COL-4	740	8.45%	10.0%	9.57%	6.3	7.1
4	CRB-1	70	10.55%	100.0%	7.51%	7.3	5.2
5	CRB-2	105	6.01%	100.0%	6.33%	6.3	6.6
6	CRG-1	428	7.42%	19.3%	2.40%	6.1	2.0
7	CRG-2	428	4.16%	19.3%	4.23%	3.4	3.5
8	DJ-1	106	6.01%	100.0%	4.93%	6.4	5.2
9	DJ-2	106	5.37%	100.0%	4.31%	5.7	4.6
10	DJ-3	223	10.16%	100.0%	13.62%	22.7	30.4
11	DJ-4	330	12.23%	100.0%	9.66%	40.3	31.9
12	HDN-1	184	6.63%	24.5%	6.43%	3.0	2.9
13	HDN-2	262	3.46%	12.6%	6.98%	1.1	2.3
14	HTG-1	440	11.42%	100.0%	10.22%	50.2	45.0
15	HTG-2	455	10.75%	100.0%	9.47%	48.9	43.1
16	HTR-1	427	9.82%	93.8%	8.97%	39.3	35.9
17	HTR-2	430	11.21%	60.3%	6.23%	29.1	16.2
18	HTR-3	460	11.64%	100.0%	6.35%	53.5	29.2
19	JB-1	530	13.38%	66.7%	7.35%	47.3	26.0
20	JB-2	530	13.51%	66.7%	6.57%	47.7	23.2
21	JB-3	530	15.65%	66.7%	8.93%	55.3	31.6
22	JB-4	526	15.64%	66.7%	8.06%	54.8	28.2
23	NTN-1	160	9.53%	100.0%	1.79%	15.2	2.9
24	NTN-2	210	9.21%	100.0%	3.90%	19.3	8.2
25	NTN-3	330	10.85%	100.0%	10.96%	35.8	36.2
26	WYO-1	335	6.90%	80.0%	5.05%	18.5	13.5

Average	9.55%	7.06%	663.0	471.5
Change	35.2%			
mW Wtd.	10.86%	7.72%		
Change	40.63%		41%	
Units with Increasing outage rates		20		
Total Number of Units		26		
Percent		77%		

Increase in Outage Capacity - mW	191.6
Savings per mW of added coal generation	270,708
Test Year Cost	$51,859,472
Oregon Allocation	25.721%
Oregon Cost	$13,338,775

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/110

NERC GENERATING AVAILABILITY DATA

June 27, 2007

Date-06/03/02

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary All Sizes 1996-2000 Data

1996-2000
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART	-
1996	30.32	63.75	78.37	81.34	86.76	84.15	4.62	7.00	6.57	9.16	3.80	97.86	349.28	-
1997	31.25	65.78	80.28	81.94	87.25	84.62	4.68	7.02	6.66	8.67	3.94	97.16	419.35	-
1998	32.21	67.78	81.54	83.12	87.22	84.37	4.70	7.23	6.91	8.65	4.02	98.15	447.56	-
1999	33.19	67.63	80.89	83.61	86.01	83.32	4.85	7.03	6.75	9.69	4.12	97.22	431.53	-
2000	33.80	72.38	84.26	85.90	87.25	84.67	4.35	6.17	6.02	8.85	3.83	98.08	499.42	-
1996-00		67.43	81.02	83.23	86.89	84.22	4.64	6.90	6.58	9.01	3.94	97.67	423.66	-

		1996	1997	1998	1999	2000	1996-00
Unit-Years	:	868	871	864	857	800	4,259
Maximum Capacity (MW)	GROSS:	332	332	340	341	346	338
	NET:	315	316	317	317	326	318
Dependable Capacity (MW)	GROSS:	330	331	339	339	344	337
	NET:	314	315	316	316	324	317
Actual Generation (MWh)	GROSS:	1,875,399	1,934,983	2,027,378	2,023,088	2,217,314	2,012,348
	NET:	1,764,001	1,820,990	1,882,089	1,877,980	2,072,580	1,880,500
Attempted Unit Starts	:	20.14	17.26	16.26	16.89	15.11	17.17
Actual Unit Starts	:	19.71	16.77	15.96	16.42	14.82	16.77
Service Hours	:	6,884.31	7,032.58	7,143.04	7,085.65	7,401.39	7,104.74
Reserve Shutdown Hours	:	736.15	610.10	497.23	442.42	262.17	513.79
Number of Occurrences	:	10.49	7.24	6.24	6.21	4.50	6.97
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.39	0.00	0.00	5.74	0.00	1.23
TOTAL AVAILABLE HOURS	:	7,620.92	7,642.77	7,640.32	7,533.88	7,663.67	7,619.84
Forced Outage Hours	:	333.76	345.26	352.29	361.17	336.36	345.87
Number of Occurrences	:	9.51	9.05	9.38	9.44	8.91	9.26
Planned Outages:							
Planned Outage Hours	:	595.13	571.73	572.76	627.00	597.48	592.67
Number of Occurrences	:	1.15	1.15	1.25	1.26	1.31	1.22
Planned Outage Ext. Hours	:	11.63	12.48	9.88	7.86	7.61	9.93
Number of Occurrences	:	0.05	0.05	0.06	0.06	0.06	0.05
Maintenance Outages:							
Maintenance Outage Hours	:	196.40	174.58	171.91	212.15	171.02	185.38

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary All MW Sizes 2000-2004 Data

2000-2004
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART	
2000	33.93	72.34	84.24	84.39	87.45	84.80	4.32	6.11	5.95	8.75	3.80	98.16	494.95	
2001	35.17	69.94	81.66	83.35	87.32	84.68	4.59	6.35	6.09	8.75	3.93	98.15	482.05	
2002	35.98	71.36	82.76	83.80	87.23	84.38	4.97	6.97	6.71	8.45	4.33	97.39	380.56	
2003	37.02	73.04	84.16	85.17	87.66	84.91	4.60	6.54	6.37	8.29	4.06	97.01	567.09	
2004	37.89	72.98	83.34	85.27	88.34	85.71	4.33	6.16	5.94	7.89	3.77	96.18	558.34	
2000-04		71.95	83.24	84.41	87.60	84.90	4.56	6.43	6.21	8.43	3.98	97.40	486.31	-

		2000	2001	2002	2003	2004	2000-04
Unit-Years	:	831.83	799.92	834.33	797.92	828.33	4,092.33
Maximum Capacity (MW)	GROSS:	340	330	335	336	339	336
	NET:	320	313	317	318	321	318
Dependable Capacity (MW)	GROSS:	338	329	333	335	337	335
	NET:	319	311	316	317	319	317
Actual Generation (MWh)	GROSS:	2,177,943	2,044,462	2,110,414	2,169,751	2,188,441	2,138,612
	NET:	2,035,887	1,915,703	1,983,482	2,037,557	2,055,148	2,005,935
Attempted Unit Starts	:	15.23	15.12	19.56	13.40	13.63	15.41
Actual Unit Starts	:	14.95	14.84	19.05	13.00	13.11	15.01
Service Hours	:	7,399.56	7,153.62	7,249.61	7,372.15	7,319.84	7,299.44
Reserve Shutdown Hours	:	271.89	474.74	380.01	278.84	422.36	365.40
Number of Occurrences	:	4.62	4.63	5.28	3.76	4.35	4.54
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	7,681.56	7,649.30	7,641.14	7,678.69	7,758.60	7,682.05
Forced Outage Hours	:	334.15	344.14	378.88	355.31	331.20	348.75
Number of Occurrences	:	8.74	8.72	9.37	9.28	8.82	8.98
Planned Outages:							
Planned Outage Hours	:	590.36	603.48	556.12	570.08	541.48	572.09
Number of Occurrences	:	3.41	7.27	2.48	6.03	4.12	4.63
Planned Outage Ext. Hours	:	5.92	14.55	11.52	8.76	5.47	9.21
Number of Occurrences	:	0.66	0.06	0.07	0.39	0.05	0.25
Maintenance Outages:							
Maintenance Outage Hours	:	171.33	146.75	170.96	146.62	144.84	156.27

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/111

PACIFICORP ROOT CAUSE ANALYSIS REPORTS

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

June 27, 2007

CONFIDENTIAL

INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/112

COST BENEFIT ANALYSES OF CONTRACTS

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

June 27, 2007

CONFIDENTIAL

INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2008 Transition Adjustment Mechanism	)
	)

ICNU/113

PACIFICORP CALL OPTION CONTRACTS CALCULATIONS

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

June 27, 2007

CONFIDENTIAL

INFORMATION

OMITTED