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IDAHO PUBLIC
UTILITIES COMMISSION

September 27, 2007

Via Hand Delivery

Jean Jewell
Idaho Public Utilities Commission
472 W. Washington
P.O. Box 83720
Boise, ID 83720-0074

Re:	In the Matter of the Application of Pacificorp DBA Rocky Mountain Power for Approval of Changes to its Electric Service Schedules – Case No.: PAC-E-07-05
Our File:	6170-3

Dear Jean:

Enclosed for filing please find an original and eight (8) copies of Dennis Peseau's Testimony in the above entitled matter. One copy has been designated as the reporter's copy, and a disk containing the testimony in ASCII format is also enclosed.

Thank you for your assistance in this matter.

Sincerely,

Conley Ward

Conley Ward

CEW/tma
cc: Service List (w/enclosures)
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES	Case No. PAC-E-07-05

DIRECT TESTIMONY

OF

DENNIS E. PESEAU

ON BEHALF OF

AGRIUM, INC.

September 28, 2007

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dennis E. Peseau. My business address is Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of Utility Resources, Inc. ("URI"). URI has consulted on a number of economic, financial and engineering matters for various private and public entities for more than twenty five years.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My resume is attached as Exhibit No. 401.

Q. WERE EXHIBIT NUMBERS 401-409 PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION?

A. Yes, on many occasions over nearly three decades.

Q. FOR WHOM ARE YOU APPEARING IN THIS CASE?

A. I am appearing on behalf of Agrium, Inc ("Agrium").

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony addresses two broad areas: (1) Rocky Mountain Power's requested revenue requirement, and (2) its proposed cost-of-service/rate design to collect the revenue requirement.

Specifically, I show that Rocky Mountain's requested 10.3% net increase in revenues is significantly inflated due to a mismatch of revenues and expenses.

With respect to Rocky Mountain's proposed cost of service/rate design I show that its cost study and resulting customer class rates are contradictory to the ratemaking principles this Commission has consistently endorsed and utilized at least since the early 1980s when I began participating in Idaho PUC cases. Rocky Mountain's proposed cost allocations are both inequitable, because they require some customer classes to pay costs they did not cause, and economically inefficient, because they are likely to exacerbate the very spikes in summer peak demands of which Rocky Mountain complains.

Q. LET'S DEAL WITH THE REVENUE REQUIREMENT MATTER FIRST. WHAT IS THE ISSUE WITH RESPECT TO THE COMPANY'S 2007 ESTIMATES OF COSTS AND REVENUES?

A. As discussed in the testimony of company witness Mr. McDougal, Page 4, Lines 11-14, Rocky Mountain is requesting approval of a year end December 31, 2006 test year, but adjusted for "known and measurable" events through December 31, 2007.

The Company classifies its adjustments in three distinct ways, as summarized by Mr. McDougal, Page 9, Lines 18-23:

> "... Rocky Mountain Power summarizes adjustments into three different types. Type 1 adjustments represent base period accounting or Commission-ordered adjustments (i.e. reversing one-time write-offs). Type II adjustments typically annualize events that occurred during the base year (i.e. contract change or wage increases). Type III adjustments reflect known and measurable events occurring in the twelve months following the base period."

Q. WHICH OF THESE CLASSES OF ADJUSTMENTS BOTHERS YOU?

A. I am concerned about the Type III adjustments to both costs and revenues. Although the Company repeatedly refers to these adjustments as "known and measurable," they are neither. Many of the adjustments are for events still in the future, and even the costs and revenues estimated from January 1, 2007 until now are not officially recorded or audited. These adjustments could more properly be labeled "anticipated and estimated" rather than "known and measurable."

Q. WHAT PROBLEMS DO YOU SEE WITH ROCKY MOUNTAIN'S PROPOSAL TO EXTEND ITS TEST YEAR TO DECEMBER 31, 2007?

A. The purpose of constructing a test year is to form a systematic and balanced record of the Company's costs and revenues in order to set rates that are fair to customers and provide a fair and reasonable rate of return to the utility. The problem with forecasting or estimating anticipated, rather than known and recorded, costs and revenues is that the temptation is great to overestimate costs and underestimate revenues. The temptation is all the greater because future costs and revenues are not subject to formal auditing, as they are not known. There is a huge difference between auditing recorded results of operations and reviewing a forecast of future results of operations. The first is a matter of verifiable facts, the latter is matter of predictions and opinions.

Q. HAS THE COMMISSION DEALT WITH SIMILAR ISSUES IN PRIOR CASES?

A. Yes. In Idaho Power's last litigated general rate case (IPUC Case No. IPC-E-03-13) Idaho Power requested similar out-of-test year adjustments. In response, I expressed deep concerns about the ability of other parties to thoroughly test the Company's forecasted upward adjustments. I have the same concerns in this case. Rather than repeating the comments I provided in the Idaho Power case, I attach as Exhibit No. 402

my testimony from that case discussing the problems inherent in mismatching test year costs and revenues under proposals such as Rocky Mountain is submitting here. I also attach, as Exhibit No. 403, Section 6 of Commission Order No. 29505, which addressed the mismatch issue and ordered a reduction of Idaho Power's revenue requirement request as a result of criticisms from both Staff and myself.

Q. HOW DO YOU PROPOSE TO ADJUST THE COMPANY'S TYPE III ADJUSTMENTS?

A. In a perfect world, I would back out all the Type III adjustments that are not in fact "known and measurable." But this would be a huge task that is far beyond the capabilities of an intervenor like Agrium, due to the vast scope of the Company's cost and rate base adjustments. But, at the very least, I propose that, if the Company's 2007 rate base and cost projections are accepted, they should be properly matched by similar 2007 revenue adjustments.

Q. DIDN'T ROCKY MOUNTAIN MAKE AN ADJUSTMENT TO REFLECT 2007 REVENUE GROWTH?

A. No, it didn't. My Exhibit No. 404 is a copy of two summary tables contained in the Company's exhibits. Page 1 of my Exhibit No. 404 provides all the revenue adjustments that the Company makes for each customer class for the year 2007. As indicated by footnote no. 4 on Page 1, the Type III adjustments (Column 6) made by Rocky Mountain are for contract price changes only for irrigators and Monsanto. None of the other customer classes's revenues have been increased to account for the significant load growth in the residential, commercial and irrigation classes. This is inconsistent and a mismatch, because the Company certainly includes, <u>on the cost side,</u>

the increased costs of meeting the increase in 2007 loads. By inflating its 2007 costs, but ignoring its 2007 revenues from increased sales, the Company exaggerates its need for a rate increase.

Q. HOW DID YOU ADJUST ROCKY MOUNTAIN'S MWH SALES TO ACCOUNT FOR 2007 SALES?

A. My adjustments are shown on my Exhibit No. 405. In order to estimate 2007 load growth, I referred to the Company's 2007 Integrated Resource Plan and noted the Company's forecast load growth for the various customer classes. As noted on Exhibit No. 405, the projected customer class growth rates are 2.2%, 3.1% and 0.6% for the residential, commercial and irrigation classes, respectively. To reach 2007 MWH sales, I multiplied each of these growth rates times the 2006 normalized MWH loads of each respective customer class. Once I had 2007 MWHs I multiplied these 2007 year sales by the class rate (revenue per MWH) to get gross incremental sales for each class. As I assume that the Company has not already inflated its 2007 year power costs as necessary to meet these additional sales, I also computed the net power costs the Company would incur to meet the 2007 load growth.

Q. WHAT RESULTING REVENUE ADJUSTMENT DO YOU ESTIMATE?

A. As shown in the bottom, right-most column of my Exhibit No. 405, the revenue adjustment necessary to reflect 2007 load growth is $1,630,500. I propose that the Commission reduce the Company's requested $18.5 million increase by this amount.

Q. TURNING TO COST OF SERVICE/RATE DESIGN ISSUES, WHAT ARE YOUR CONCLUSIONS REGARDING ROCKY MOUNTAIN'S PROPSAL?

A. My testimony demonstrates that Rocky Mountain's cost of service proposal suffers from the following defects:

1. Rocky Mountain's cost study errs in assuming that only certain generation resources are used to meet its summer season peak loads, when in fact, baseload, intermediate and peak resources are required at periods of maximum demand;

2. Rocky Mountain's cost allocations and eventual rate design are dramatically changed if its cost study is modified to more "peak-sensitive" allocators that reflect its summer peak characteristics;

3. The Company's cost allocation methods discriminate against residential and higher load factor customers by producing rates that are in excess of the cost of service.

4. Rocky Mountain's cost allocation procedures are likely to promote on-peak demand by customers, which is driving its need for new generation resources;

5. In addition to the poor peak-period price signals stemming from Rocky Mountain's proposed cost study and rate design, basing rates on such a study will inappropriately damage the competitive position of Idaho industry, including Agrium, by charging higher rates than economically justified.

Q. THE COMMON THEME OF THESE CRITICISMS OF ROCKY MOUNTAIN'S COST OF SERVICE STUDY IS THAT IT FAILS TO PROPERLY ALLOCATE PEAK DEMAND COSTS. WHY IS THIS IMPORTANT?

A. In general, utilities incur higher costs to serve both demand (capacity) and energy during their peak load periods. This is true for Rocky Mountain as well. Consumers are best served by pricing both demand and energy at rates that reflect these higher costs during peak seasons, and correspondingly lower rates during lower cost off-peak seasons. The reason is that each consumer's welfare is served by him or her recognizing the seasonal cost differences and, to the extent possible, shifting consumption to lower cost periods. This natural usage adjustment is further beneficial in that these shifts tend to level out demand over the year, allowing more efficient utilization of generating and transmission plant (by increasing system load factor).

Q. DOES THE COST OF SERVICE STUDY OFFERED BY ROCKY MOUNTAIN ALLOCATE DEMAND-RELATED COSTS IN A NORMAL MANNER?

A. No. Rocky Mountain allocates the vast majority of its generation resource costs <u>equally to all months of the year</u>. The Company's equal twelve month allocation essentially suggests that its monthly resource availability, monthly loads and costs are equal in all months of the year. This is clearly not the case.

This cost of service proposed by Rocky Mountain is not only illogical, it is also quite different from any cost of service studies recently offered in other proceedings before this Commission, and also very different from the cost of service studies originally developed by PacifiCorp in the 1970s-1990.

Since 1990, PacifiCorp had not filed a class cost of service study of any kind until the PAC-E-02-1 case, which was settled by stipulation. The most recent PAC-E-05-01 general rate case was also settled, with all customer class rates receiving a uniform 1.7% rate increase. Thus, the Commission did not review or approve a cost of service methodology in either case.

Q. WHY DO YOU HIGHLIGHT THIS HISTORY OF A LACK OF PACIFICORP COST OF SERVICE STUDIES REVIEWED IN IDAHO?

A. The cost of service study offered by PacifiCorp in this proceeding, in my opinion, is so methodologically different from other cost of service studies and costing principles adopted by this Commission for rate design purposes that it should not be relied upon. At the very least, it should be assessed in a separate cost of service proceeding. In the interim, the Commission should either continue with principles of weighting costs as it has done in the past, or again order a uniform rate increase across classes as it did in the last general rate case PAC-E-05-01.

Q. HOW SHOULD COSTS BE PROPERLY WEIGHTED?

A. In order to reflect the actual cost of service, a cost allocation method must reflect the differences in costs among seasons, as this Commission has recognized in the past. As shown in my Exhibit No. 406, Rocky Mountain has historically been a summer-peaking system. This same exhibit shows that, according to the Company's own forecast, it expects to remain a summer-peaking utility well into the future.

Q. WHAT DOES THIS IMPLY FOR THE COST ALLOCATIONS USED IN THE COST OF SERVICE STUDY?

A. As recognized by Commission orders dating back at least a couple of decades, the cost of service allocators used to design rates should, in some fashion, weight demand and energy costs back to the peak months because these months cause higher costs.

Q. HOW IS SEASONAL COST DIFFERENTIATION TYPICALLY HANDLED IN A COST OF SERVICE STUDY?

A. Typically, monthly demands are compared and higher demand months are allocated the higher costs that the utility has to pay for serving demand in these higher load months.

Q. HOW ARE THESE HIGHER DEMAND MONTHS WEIGHTED RELATIVE TO LOWER COST OFF-PEAK SEASONS?

A. There have been a number of weighting methods developed and used in Idaho. In some Idaho rate cases, monthly marginal costs have been used to weight monthly peak loads to develop the capacity allocators used in the various cost of service studies.

More recently in Idaho, these demand-related costs have been allocated on the risk of outages ("loss of load probability") that the months of high loads place on the system. Whatever method is used, a proper cost of service study must assign or allocate relatively higher costs to the peak season months because these are the months for which capacity or generating resources are built.

Q. SPECIFICALLY, HOW SHOULD DEMAND-RELATED COSTS BE ALLOCATED IN THIS CASE?

A. Below I produce three distinct cost of service studies intended to be consistent with proper weighting of demand-related costs. Each method, although different, reflects seasonal differences in the weighting of demand costs typically used or endorsed by Idaho Power, the PUC Staff, and myself, in cases dating from the 1980s to the present.

Q. HAVE THESE WEIGHTING METHODS BECOME DATED?

A. No. The methods and principles were and continue to be well grounded in economic theory, in that they attempt to allocate more costs to higher-cost seasons.

Q. PLEASE DESCRIBE THE ALTERNATIVE COST OF SERVICE STUDIES YOU ARE PRESENTING.

The first cost of service study I present uses all of the basic input data, assumptions and functionalization and classification methods used in Rocky Mountain's study. The only modification I make is in the weighting of demand related costs on the basis of the peak demand months identified in Rocky Mountain's study. The Company's study identifies its forecast peak load months for each of the years 2007-2016 as the summer months June, July and August, and the winter month of December. These are the principal months for which its peaking resources are purchased and to which related costs should be allocated.

This alternative study therefore proposes to allocate the demand-related costs of Rocky Mountain generation to these peak months. Other utility systems in this region, for example Idaho Power and Sierra Pacific Power, normally have similar peak month allocations.

A comparison of my four month allocation cost study is shown under column E, entitled "3 Sum-1Win" in the following table.

Agrium
Alternative Rate Indexes By Rate Schedule
State of Idaho
12 Months Ending December 2006

Alternative Monthly Weights for Demand-Related Costs

A	B	C	D	E	F	G

Line No.	Schedule No.	Description	Annual Revenue	Rocky Mtn Return Index	3 Sum-1Win Return Index	1 CP Return Index	3 CP Return Index
1	01	Residential	29,653,369	1.16	1.40	1.30	1.72
2	36	Residential - TOD	21,362,235	1.25	1.67	2.12	2.10
3	06	General Service-Large	18,609,425	1.86	2.42	3.09	2.69
4	08	General Service - Med	130,255	1.78	2.50	2.53	2.74
5	09	General Service - High	5,061,143	2.31	2.74	2.56	2.84
6	10	Irrigation	39,404,679	1.05	0.27	(0.06)	(0.18)
7	07,11,12	Street & Area Lighting	326,298	(3.12)	(3.12)	(3.14)	(3.14)
8	12	Traffic Signals	15,526	2.53	2.78	3.31	2.98
9	19	Space Heating	635,620	2.14	3.26	3.52	3.78
10	23	General Service-Small	10,711,252	2.07	2.58	3.03	2.77
11	SPC	Contract 1	3,998,852	0.69	0.98	1.09	1.07
12	SPC	Contract 2	48,668,727	0.21	0.41	0.57	0.66
13	Total	State of Idaho -	178,577,381	1.00	1.00	1.00	1.00

The column immediately to the left, titled "Rocky Mtn," is the Company's proposed cost study. These columns each show the so-called "rate of return" index of each customer class under each study. These indexes average "one" or "unity." Any customer class ratio that is greater (less) than unity is, according to the particular study, paying higher (lower) that its cost of service.

For example, Rocky Mountain's study produces an index of 1.16 for Schedule No. 1, the residential class. My modified 4 months study produces an index of 1.4 for the residential class. Thus under my study, the residential class should receive a lower rate increase (3.81%) instead of the Company's proposed 7.83% rate increase. My client Agrium, which is class "Contract 1," is shown under the Company's study to have an index of only .69, from which the Company concludes that Agrium should receive a rate increase well above the overall average increase of 10.34%. Under my modified four peak month study, however, the index for Agrium is increased to nearly unity (.98) indicating an average rate increase.

Q. WHAT DO THE NEXT TWO COLUMNS OF THE TABLE SHOW?

A. The column titled "1 CP " again uses all the data and costing methods contained in Rocky Mountain's study except that the demand-related costs are allocated to the single peak month of July.

The last column, titled "3 CP" allocated demand-related costs to the three summer season peak months.

Q. HAVE YOU INCLUDED SUMMARIES OF THE COST OF SERVICE STUDIES DESCRIBED IN THE TABLE ABOVE AND IN YOUR TESTIMONY?

A. Yes. The summary cost of service studies are attached as Exhibit Nos. 407-409. The voluminous model information can be provided separately on disk upon request.

Q. IS THERE A GENERAL CONCLUSION THAT YOU REACH COMPARING THE COMPANY'S STUDY WITH ANY OR ALL OF YOUR PEAK-RESPONSIBILITY STUDIES?

A. Yes, there is a very clear conclusion. In any of the three cost studies that allocate demand-related costs to peak demand periods, the residential class, Agrium and other higher load factor classes should receive lower rate increases than proposed by Rocky Mountain.

This good news for these classes is counterbalanced by bad news for Schedule No. 10, the irrigation class. Rocky Mountain's cost study produces a rate of return index of 1.05 for the irrigators, resulting in its proposed 9.84% increase. Under each of my three demand-related allocator methods, the irrigators are shown to be well under the average rate of return. The irrigators have indexes of .27, -0.06 and -0.18 in the four month, single month peak and three summer month peak allocator studies I performed. It is clear that the only way that Rocky Mountain could have produced its result for the irrigation class is by allocating the high summer season demand-related costs to the spring and the fall low demand months through the use of an equal twelve month allocation.

Unfortunately, there is a great cost to the Company's residential and higher load factor customers from its shifting of allocated costs out of the peak season months.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY THAT STATEMENT?

A. A harsh economic fact is that over time markets and consumer preferences change in a manner that helps or hurts various industries. At times it is tempting "for the sake of the economy" to attempt to subsidize, by various means, certain sectors of the economy. This happened in the 1970s in the automotive industry, and has for decades been true for passenger rail transportation. But when the ratemaking process is used to subsidize a particular class, other classes are inevitably harmed because the ratemaking process is a zero sum game. Moreover, economic efficiency suffers, to the long run detriment of all.

Consequently, it has been my experience that the Idaho Commission has, over many years, attempted to first ascertain, as accurately as possible, the nature of cost causation of various customer classes, and then move class rates in the direction of these costs. This has not always been easy, but the Commission has repeatedly recognized that any established subsidy to rate classes causes equal economic dislocations to other rate classes.

In the present proceeding, I conclude that Rocky Mountain's proposed cost of service and rate design study does not capture and identify the essential seasonal time differentiation of the Company's system costs. And, as the study moves large amounts of dollars out of the summer season, the rate design it proposes significantly harms the Company's residential and higher load factor industrial customers. In the interest of economic neutrality, and to protect the longer-term economic viability of its other customers, the Commission should reject Rocky Mountain's cost of service study.

Q. ARE YOU SUGGESTING THERE IS A SINGLE, CLEARLY OPTIMUM AND UNCHANGING COST METHOD THAT SHOULD BE USED IN THIS CASE?

A. I wish that I could say that there is such a single costing method, but, of course, this Commission has heard many such "superiority" arguments over the years. And I too am making similar arguments. There are, however, clear principles we must follow, and allocating demand-related or capacity costs disproportionately to off peak seasons is not one of them.

Q. ARE THERE ALTERNATIVES AVAILABLE IN THESE PROCEEDINGS TO FAIRLY DESIGN CUSTOMER CLASS RATES?

A. I believe there are. When faced with the need to gradually move class rates in the right direction in relation to costs, this Commission has often ordered a uniform or equal percentage increase in rates for those classes relatively close to cost of service, while raising a particular class' rates that was well under cost of service by a higher percentage. In this case, Schedule No. 10, the irrigation class, stands out as the candidate for a larger than average rate increase.

Q. BASED ON ROCKY MOUNTAIN'S REQUESTED 10.3% REVENUE INCREASE, DO YOU HAVE A PROPOSAL IN THIS REGARD?

A. Yes. My own testimony, and doubtless the testimonies of other parties argue for a lower overall rate increase, but regardless of how that issue turns out, the Commission should use one or more of the cost of service alternatives I have suggested as the basis for its rate design.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 27th day of September, 2007, I caused to be served a true and correct copy of the foregoing by the method indicated below, and addressed to the following:

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Conley E. Ward

STATEMENT OF OCCUPATIONAL AND
EDUCATIONAL HISTORY AND QUALIFICATIONS
DENNIS E. PESEAU

Dr. Peseau has conducted economic and financial studies for regulated industries for the past thirty-five years. In 1972, he was employed by Southern California Edison Company as Associate Economic Analyst, and later as Economic Analyst. His responsibilities included review of financial testimony, incremental cost studies, rate design, econometric estimation of demand elasticities and various areas in the field of energy and economic growth. Also, he was asked by Edison Electrical Institute to study and evaluate several prominent energy models as part of the Ad Hoc Committee on Economic Growth and Energy Pricing.

From 1974 to 1978, Dr. Peseau was employed by the Public Utility Commissioner of Oregon as Senior Economist. There he conducted a number of economic and financial studies and prepared testimony pertaining to public utilities.

In 1978 Dr. Peseau established the Northwest office of Zinder Companies, Inc. He has since submitted testimony on economic and financial matters before state regulatory commissions in Alaska, California, Idaho, Maryland, Minnesota, Montana, Nevada, Washington, Wyoming, the District of Columbia, the Bonneville Power Administration and the Public Utilities Board of Alberta on over one hundred occasions. He has conducted marginal cost and rate design studies and prepared testimony on these matters in Alaska, California, Idaho, Maryland, Minnesota, Nevada, Oregon, Washington and in the District of Columbia. He has also conducted cost and rate studies regarding PURPA issues in the states of Alaska, California, Idaho, Montana, Nevada, New York, Washington, and Washington, D.C.

Dr. Peseau holds the B.A., M.A. and Ph.D. degrees in economics.

He has co-authored a book in the field of industrial organization entitled, Size, Profits and Executive Compensation in the Large Corporation, which devotes a chapter to regulated industries.

Dr. Peseau has published articles in the following professional journals: Review of Economics and Statistics, Atlantic Economic Journal, Journal of Financial Management, and Journal of Regional Science. His articles have been read before the Econometric Society, the Western Economic Association, the Financial Management Association, the Regional Science Association and universities in the United Kingdom as well as in the United States.

He has guest lectured on marginal costing methods in seminars in New Jersey and California for the Center of Professional Advancement. He has also guest lectured on cost of capital for the public utility industry before the Pacific Coast Gas and Electric Association, and for the Executive Seminar at the Colgate Darden Graduate School of Business, University of Virginia.

Dr. Peseau and his firm have participated with and been members of the American Economic Association, the American Financial Association, the Western Economic Association, the Atlantic Economic Association and the Financial

Management Association. He was formerly a member of the Staff Subcommittee on Economics of the National Association of Regulatory Utility Commissioners.

Dr. Peseau has been President of Utility Resources, Inc. since 1985.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS INTERIM AND BASE RATES AND CHARGES FOR ELECTRIC SERVCE	Case No. IPC-E-03-13

DIRECT TESTIMONY

OF

DENNIS E. PESEAU

ON BEHALF OF

MICRON TECHNOLOGY, INC.

ORIG

"trust, but verify" exercise, so it obviously increases the burden on the Staff, as well as all parties' reliance on their diligence.

The second complicating factor is that some of the adjustments proposed by the Staff and Intervenors cannot be quantified with precision because the "base case" that we are working with will presumably change when all the final numbers are in. This is apt to create some confusion during the hearings, and the Commission may want to give some thought to how to incorporate into the evidentiary record the true-up revisions to both the Company's base case and the Staff and Intervenors' adjustments.

Revenue Requirement Issues

Q. LET'S TURN NOW TO THE MERITS OF THE CASE. YOU EARLIER STATED THAT IDAHO POWER'S CASE IN CHIEF CONTAINS A MISMATCH OF REVENUES AND EXPENSES. PLEASE EXPLAIN WHAT YOU MEAN BY THE WORD "MISMATCH."

A. Idaho Power calculates its test year revenues in a straightforward manner. For the first six months of the test year, actual data is used. Projections are employed for the last six months. These projections will ultimately be replaced by actual figures before the close of the proceedings. Thus, by the end of the proceedings, test year revenues will consist of 2003 actual figures, "normalized" for weather and other standard adjustments.

On the other side of the ledger, expenses and rate base are treated in a much different manner. Again the Company uses six months of actual data and six months of projections. But it then goes on to annualize operating and maintenance expenses and rate base to year-end levels. In effect, this annualization treats these costs as if year-end levels had been in effect throughout the test year. This is a clear mismatch of revenues and expenses because revenues are "centered" on June 30, 2003, while rate base and expenses are centered on December 31, 2003.

To make this mismatch worse, Idaho Power further adds allegedly "known and measurable changes" in rate base and expenses that it forecasts for the period from January 1, 2004 through May 31, 2004. These adjustments include rate base additions of $18,165,002, operating and maintenance increases of $9,907,923, associated depreciation increases of $447.375, and an adjustment for a 2004 increase in depreciation rates totaling $5,976,270.

The net effect looks very much like a partially projected test year ending on May 31, 2004 for rate base and expenses, matched against revenues centered on June 30, 2003. The resulting mismatch overstates Idaho Power's revenue requirement and is not defensible.

Q. HOW SHOULD THIS MISMATCH BE CORRECTED?

A. There are basically two alternative remedies available. The first would be to reverse the annualizing entries and properly match test year averages on both sides of the ledger. The second alternative is to annualize revenues in the same manner as rate base and expenses.

Q. DO YOU HAVE A PREFERENCE BETWEEN THESE TWO ALTERNATIVES?

A. On the whole, I think annualizing revenues to 2003 year-end levels is the preferable course for two reasons. First, it is much simpler to annualize revenues than to back out Idaho Power's annualizing adjustments from numerous cost and rate base categories. Moreover, annualizing revenues produces a more forward-looking result than reversing the expense and rate base annualizations.

I recognize, however, that when faced with a similar mismatch problem in the last Idaho Power rate case, the Commission ordered a reversal of the improper annualization of expenses. Order No. 25880, pp. 3-4. In theory this course of action is equally acceptable, but it poses a greater risk of computational errors just because of the number of adjustments required. Consequently, I continue to recommend annualizing earnings instead.

Q. HAVE YOU CALCULATED AN APPROPRIATE ANNUALIZATION ADJUSTMENT FOR TEST YEAR REVENUES?

A. Assuming a revenue growth rate of 4.06%, annualizing revenues to year-end levels would add $9,731,765 to Idaho Power's test year revenues. This provides an accurate match between revenues and rate base and expenses.

Q. SHOULD IDAHO POWER'S PROPOSED 2004 KNOWN AND MEASURABLE CHANGES BE ADDED TO THE TEST YEAR BASE CASE?

A. Only in part. Adding known and measurable changes to a test year base case is a legitimate regulatory tool, but it must be used with extreme caution because of the high potential for abuse. Post-test year adjustments should only be accepted when they are in fact truly known and measurable. In order to qualify, a proposed adjustment must be virtually certain to occur, and its revenue requirement impact must be precisely and reliably quantifiable.

Only one of Idaho Power's proposed adjustments meets this test. The 2004 increase in depreciation rates is in fact certain to occur, and its impact on revenue requirements can be quantified down to the penny. This $5,976,220 known and measurable adjustment should be accepted. The other proposed adjustments should be rejected.

Q. WHAT IS YOUR RATIONALE FOR REJECTING THE REMAINING ADJUSTMENTS?

A. The other proposed adjustments fall into two separate categories. Of the $9,907,923 of known and measurable changes to operations and maintenance costs, $5,114,821 is for a 7% incentive pay package to be implemented in 2004. My understanding is that this incentive package is over and above normal pay increases, and is designed as a reward for cost savings to be realized as a result of extraordinary employee efforts.

The first problem, of course, is that this is not truly a <u>known</u> change because the incentive will presumably not be paid if the savings don't actually materialize. Furthermore, this type of incentive pay makes no sense unless it results in savings that exceed the incentive pay, in which case there is no need to further reward the Company for a program that will be essentially self funding. In fact, if the incentive pay program is successful, the net effect should be a reduction, rather than an increase, in Idaho Power's revenue requirement.

Thus, this adjustment fails both elements of the test. It is far from certain to occur, and its net impact on revenue requirements is impossible to quantify, and in fact could as easily be positive as negative.

Q. PLEASE EXPLAIN WHY THE REMAINING GROUP OF ADJUSTMENTS SHOULD BE DISALLOWED.

A. The remaining proposed adjustments are essentially projected or budgeted increases in rate base (with associated depreciation) and operating and maintenance expenses. These projections fail the known and measurable test on a number of grounds.

In the first place, they are not sufficiently certain to occur. If budgeted figures were deemed sufficiently reliable for ratemaking purposes, the Commission would presumable accept a fully projected test year. But to the best of my knowledge, the Idaho Commission has never accepted a fully projected test year because of the inherent untrustworthiness of projected figures.

Second, the net revenue requirement impact of these budgeted 2004 expenditures is unknown because Idaho Power has focused on only one side of the cost-benefit equation. Like other businesses, utilities generally do not make additional investments or increase their expenses unless they can generate additional revenues and profits, either by serving additional customers, or by cutting costs or increasing margins. There is no reason to assume this is not the case here. The projected expenditures Idaho Power has identified must be presumed to generate additional revenues or other benefits that would offset their costs, in whole or in part. But Idaho Power has made no attempt to identify these offsetting benefits. Instead, it has focused on only one side of the ledger. Stated another way, this is another mismatch problem, where the Company is attempting to recover for projected cost increases while ignoring the increased revenues that would occur in the corresponding time frame. This violates one of the most important tenets of ratemaking, and should be rejected.

Q. YOU EARLIER STATED THAT KNOWN AND MEASURABLE ADJUSTMENTS SHOULD BE APPROACHED WITH CAUTION BECAUSE OF THEIR HIGH POTENTIAL FOR ABUSE. WHAT DID YOU MEAN BY THAT STATEMENT?

A. One of the obvious problems with known and measurable changes to test year results is that the utility has every incentive to identify changes that will increase its revenue requirement, but no incentive to ferret out changes that would decrease that revenue requirement. I am not suggesting that Idaho Power would deliberately conceal changes that would reduce its revenue requirement, just that it has no reason to look for them.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes. Idaho Power's Exhibit No. 14 calculates the Company's embedded cost of long-term debt. As that exhibit shows, one of Idaho Power's nine first mortgage bonds, a $50,000,000 issue with an effective cost of 8.54%, is scheduled to come due in March of 2004. At today's cost of capital, Idaho Power can roll this issue over at a savings of at least 269 basis points. This is a known and measurable change that will obviously decrease Idaho Power's cost of capital and revenue requirement, but the Company failed to include it in its known and measurable adjustments.

I will quantify the amount of this adjustment in my discussion of cost of capital issues, but my point here is that Idaho Power obviously did not look very hard for known and measurable changes that would benefit ratepayers rather than shareholders, or it would have included this item in its list of changes. This naturally makes one wonder what other favorable changes could be identified if Idaho Power had an incentive to seek them out. In any event, the one sided nature of the Company's incentives is why I pointed out there is a high potential for abuse in the use of known and measurable changes.

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON REVENUE REQUIREMENT ISSUES.

A. Idaho Power's proposed test year contains a gross mismatch of revenues and expenses. I recommend remedying this defect by annualizing revenues to year-end 2003. This will reduce Idaho Power's requested increase by $9,731,765.

I further recommend that the Commission reject all of Idaho Power's post-test year adjustments except the known and measurable increase in depreciation rates. This reduces the Company's claimed Idaho jurisdictional revenue requirement by $11,786,222.

Cost of Capital Issues

Q. HAVE YOU REVIEWED DR. WILLIAM AVERA'S TESTIMONY REGARDING THE COST OF EQUITY FOR IDAHO POWER?

A. Yes, I have.

Q. WHAT IS YOUR INITIAL IMPRESSION OF THAT TESTIMONY?

A. Dr. Avera, like most cost of capital witness, discusses several alternative methods of determining Idaho Power's cost of equity. In general, most of these approaches follow modern cost of capital theories and methodologies. But his presentation suffers from stale capital market data and, with the updates I identify below, his proposed return on equity estimate must fall dramatically. I also disagree with his general characterization of the state of the electric utility industry.

Office of the Secretary
Service Date
May 25, 2004

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS INTERIM AND BASE RATES AND CHARGES FOR ELECTRIC SERVICE.	))))))	**CASE NO. IPC-E-03-13** **ORDER NO. 29505**

ISSUED MAY 25, 2004

BOISE, IDAHO

may have been cost-effective in light of the current relicensing proceedings. The Commission also notes that the inclusion of these costs in rate base serves as a reminder of the financial impact that projects related to relicensing have on customer rates. We encourage Idaho Power to evaluate current park usage fees to minimize park costs to be recovered from ratepayers in the future. Tr. at 1566.

6. Known and Measurable Physical Plant Improvements.

Idaho Power proposed an upward adjustment to rate base for plant improvements it expects to complete by May 2004. Because the costs are known and measurable, Idaho Power added $18,388,690 to the 2003 test year rate base for upgrades to the Brownlee-Oxbow transmission line and Star, Vallivue, Midrose and Goshen transmission stations. Tr. at 555. Staff witness Leckie agreed these known improvement costs should be included in rate base, but objected to the manner in which the Company added the costs, noting "it is a question of how the cost of these projects should be included in computing the 13-month average rate base." Tr. at 1555. The Company proposed to add the entire amount to each month of the test year rate base, and also increase related test year expenses for these projects by $447,375 for depreciation, $112,171 for property taxes, and $8,199 for insurance. Noting that the Company did not make any attempt "in its testimony or exhibits to quantify customer benefits that result from these additions to plant," Mr. Leckie claimed including only the costs without adjusting revenues created a mismatch in the test year that "is not fair to ratepayers." Tr. at 1556. Staff recommended the project costs be added to rate base only in one month of the test year and then averaged over the 13-month test year. In that way, the projects would be recognized in rate base with no need for an offsetting increase in revenues. Staff's recommendation would decrease the Company's adjustment to rate base by $16,974,175. Tr. at 1561.

Micron also objected to the Company's proposed known and measurable adjustments for major plant additions. Dr. Peseau testified that with the exception of depreciation, all remaining known and measurable adjustments should be denied because they are not sufficiently certain to occur and Idaho Power has made no effort to quantify offsetting revenue benefits like the embedded cost of long-term debt. Tr. at 2434-36. Micron's proposed adjustment would reduce Idaho revenue requirement by $11,768,222. Tr. at 2438.

In rebuttal testimony, the Company argued that the project costs should be included in the test year rate base. Although falling outside the test year, Company witness Obenchain insisted they "will be plant-in-service and used and useful by the time the rates determined by this proceeding go into effect." Tr. at 2792. He also maintained that "customers are receiving the benefits of these sizable plant investments now," these transmission projects increase the system reliability, and that "even though these investments may not produce revenues[,] they do produce benefits for customers." Tr. at 2795.

It is true that these projects, if completed on schedule as planned, will be operational by the time new rates go into effect, and thus produce a benefit for customers. But it also is true that these projects produce a benefit for Idaho Power that may include additional revenues, and the Company made no effort to quantify the benefits it will receive from the additional investments. The Commission generally believes that putting the known and measurable adjustments in rate base for a full year creates a mismatch between revenues and expenses in the test year if benefits are not needed too. Although the Company insists that these plant investments will not generate additional revenues, the Commission has previously noted above and in Order No. 20592 that all depreciable investments produce revenue. Idaho Power's newly built transmission stations will reduce maintenance expenses for the old Goshen station and create additional revenues from the growth served by the new Star, Vallivue and Midrose substations. Again, we know these benefits exist but are without the information necessary to precisely calculate them, and thus we must use some reasonable means of estimating them.

As we explained in the "Annualized Plant Adjustments" section (*supra* at 5), we generally expect all utilities to identify expense saving and revenue producing effects when proposing rate base adjustments outside the test year for major plant additions. In keeping with our desire to promote reasonable plant additions, we also find it reasonable to allow Idaho Power to include the $18,388,690 of known and measurable plant adjustments for the Brownlee-Oxbow transmission line and Star, Vallivue, Midrose and Goshen transmission stations in rate base and earn a return on this investment.

However, we also believe it is critical to match revenues and expenses to these plant additions. We, therefore, find it reasonable to use a proxy for the actual additional revenues or reduced expenses that have not been adequately quantified by Idaho Power and impute $1,031,733 of revenue and reduced expenses in calculating the Company's revenue requirement. This revenue and expense reduction imputation for the known and measurable adjustment is calculated in the same manner as that imputed for the annualized plant. The account categories for the known and measurable plant include Transmission Station Equipment and Transmission Lines.

The impact of this imputation is less than either the $16,974,175 Staff-proposed rate base adjustment or the Micron-proposed adjustment that attempted to address this mismatch by reducing the Company's revenue requirement. Again, this imputed revenue may be conservative but we believe the overall result is just and reasonable.

The approximately $1.9 million in cash flow associated with this plant from depreciation and the return is greater than the $1,031,733 imputed for revenues and reduced expenses. Even with this imputation, the Commission has allowed Idaho Power to recover all out of pocket expenses associated with this known and measurable plant adjustment as it did with the annualizing adjustment. Although this imputation achieves a fair result in this case, the specific calculation should not be used as precedent in other cases.

*7. **Document Management System.***

Idaho Power added $106,275 to the test year rate base for the entire cost of a Shareowners' Document Management System. Noting that Idaho Power only has one shareowner, IDACORP, Staff testified that only IDACORP has enough shareowners to require a shareowners' document management system, and thus the benefits of the system flow mostly to IDACORP. Tr. at 1569. Staff witness Leckie recommended the cost of the system be shared equally between the ratepayers and shareowners, which "is the same treatment as that used to allocate Board of Directors' fees." Tr. at 1570. Staff's recommendation would remove $53,137 from Idaho Power's proposed rate base, and reduce the Company's annual depreciation expense by $7,295. *Id.* The Company offered no response to Staff's proposed adjustment in its rebuttal testimony.

The Commission finds that including the entire cost of the Shareowners' Document Management System in rate base would be unfair to ratepayers. Because the system benefits IDACORP in its administrative responsibilities much like the fees paid to its Board of Directors, we find that it should be allocated the same as the Board of Director's fees in this case. Therefore, only one-half the cost of the system should be included in Idaho Power's rate base. Accordingly, Idaho Power's rate base adjustment will be reduced by $53,137 reflecting the cost of the system, and by $7,295 for reduced depreciation expense.

Table 1 Revenue
Rocky Mountain Power
State of Idaho
Summary of Revenue Adjustments
12 Months Ending December 2006

($000's)

	A	B	C	D	E	F	G	H
		Adj 3.3	**Adj 3.1**			**Adj 3.2**	**Adj 3.3**	
	Booked Revenue	Normalizing Adjustments[1]	Temperature Normalization	Total Type 1 Adjustments	Total Type 1 Adjusted Revenue	Total Type 2 Adjustments[3]	Total Type 3 Proforma Adjustment[4]	Total Adjusted Revenue
Residential	$32,976	$19,043	($969)	$18,074	$51,050	$0	$0	$51,050
Commercial	25,310	1,181	(810)	371	25,680	(8)	-	25,672
Industrial2	35,485	11,988	-	11,988	47,473	(0)	1,879	49,351
Public St & Hwy	252	(0)	-	(0)	251	-	-	251
Nu West	4,201	(302)	-	(302)	3,899	100	-	3,999
Monsanto-Firm	2,268	6	-	6	2,273	-	381	2,654
Monsanto-Non Firm	39,057	(117)	-	(117)	38,940	-	6,397	45,337
Monsanto Curtailed[5]	-	678	-	678	678	-	-	678
Monsanto-Subtotal	$ 41,325	$ 566	$ -	$ 566	$ 41,891	$ -	$ 6,777	$ 48,669
Total Idaho	$139,548	**$32,476**	**($1,779)**	$30,697	$170,245	**$92**	**$8,656**	$178,993
Source / Formula	305F	Table 3	Customer Info. Services	B + C	A+D	Table 3	Table 3	E+F+G

1. Includes removal of BPA credit $31,752, removal of Acq. Commitment revenues $525, and normalization of revenues $343.
2. Includes Irrigation.
3. Includes annualization of NuWest $100 and Schedule 19 billed cheaper -$8.
4. Proforma change of Monsanto contract and irrigation price change adjustment.
5. The revenue associated with curtailed load is added back, since the reduction in loads due to curtailment is considered an acquisition of resources to meet the load.

Exhibit No. 404
Agrium

Table 1 MWHs
Rocky Mountain Power
State of Idaho
Summary of MWH Adjustments
12 Months Ending December 2006

	A	B	C	D
	Booked MWh's	Total Type 1 Adjustments[1]	Type 2 Adjustments[4]	Total Adjusted MWH
Residential	677,539	(6,751)	0	670,788
Commercial	400,705	(18,810)	0	381,895
Industrial[2]	774,006	(4,361)	0	769,644
Public St & Hwy	2,321	6	0	2,326
Nu West	119,309	(9,379)	0	109,930
Monsanto Firm	78,840	0	0	78,840
Monsanto Non Firm	1,278,860	2,897	0	1,281,757
Monsanto Curtailed[3]	0	34,948	0	34,948
Monsanto-Subtotal	1,357,700	37,845	0	1,395,545
Total Idaho	3,331,579	(1,450)	0	3,330,129
Source / Formula	305F	Table 2	Table 2	A + B + C

1. Type 1 adjustment includes temperature adjustment, out of period adjustment, normalization of special contracts, and adjustment made to reconcile Blocking kWh with booked kWh.
2. Includes irrigation.
3. The curtailed load is added back, since the reduction in loads due to curtailment is considered an acquisition of resources to meet the load.
4. Type 2 adjustment includes schedule 19 billed cheaper

Revenues Direct Assigned

Agrium
Adjustment to 2007 Revenues to Account for Load Growth
Correcting Mismatch of Costs and Revenues
State of Idaho
MSP Protocol
Revenue - Normalized

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Customer Class	Residential Schedule 1	Residential Schedule 36	General Srv Large Power Schedule 6	General Srv Med Voltage Schedule 8	General Srv High Voltage Schedule 9	Irrigation Schedule 10	St. & Area Lgt Schedules 7, 11, 12	Traffic Sgnls Schedule 12	Space Heating Schedule 19	General Srv Req. Schedule 23	Contract 1	Contract 2	Total
1	Residential	29,653,369	21,362,235						-					$51,015,604
2														
3	Commercial			13,772,507		1,367,188				624,448	9,619,799			$25,383,942
4														
5	Industrial			4,836,918	130,255	3,693,955	39,404,679			11,172	1,091,453	3,998,852	$48,668,727	$101,836,011
6														
7	Lighting							326,298	15,526					$341,824
8														
9	OSPA													
10														
11	T - 42 Revenues	$29,653,369	$21,362,235	$18,609,425	$130,255	$5,061,143	$39,404,679	$326,298	$15,526	$635,620	$10,711,252	$3,998,852	$48,668,727	$178,577,381

	B	C	D	E	F	G	H	I	J	K	L	M	N
Total Mwh at Input	395,317	351,716	340,443	2,399	114,915	657,455	2,860	210	10,580	146,804	114,924	1,458,945	3,596,569
Revenue per Mwh at Input ($/Mwh)	75.01	60.74	54.66	54.29	44.04	59.94	114.07	73.98	60.08	72.96	34.80	33.36	
Net Power Cost per Mwh (Widmer)	15.35	15.35	15.35	15.35	15.35	15.35	15.35	15.35	15.35	15.35	15.35	15.35	
Net Revenue per Mwh	59.66	45.39	39.31	38.94	28.69	44.59	98.72	58.63	44.73	57.61	19.45	18.01	
Residential Load Growth at 2.2%	8,697	7,738											16,435
Commercial Load Growth at 3.1%			7,811		962				322	4,087			13,182
Irrigation Load Growth at 0.6%						3,945							3,945
Pro Forma Adjustment to Test Year Revenues for 2007 Sales Growth	$518,876	$351,195	$307,055		$27,611	$175,876			$14,412	$235,475			$1,630,500

PAC-E-07-05/Rocky Mountain Power
August 29, 2007
Agrium Data Request 6

Agrium Data Request 6

Provide the most recent forecasts of monthly coincident peak loads for the next 10 years.

Response to Agrium Data Request 6

Below is the Forecasted Coincidental Peak Load in megawatts for the next 10 years. This is based on the forecast used in the 2007 Integrated Resource Plan.

Forecasted Coincidental Peak Load in Megawatts

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Jan	7,976	8,153	8,610	9,032	9,179	9,377	9,573	9,679	9,869	10,070
Feb	8,005	8,018	8,644	8,873	9,120	9,072	9,435	9,571	9,751	9,722
Mar	7,723	7,761	8,283	8,502	8,733	8,762	8,978	9,130	9,305	9,363
Apr	7,062	7,272	7,503	7,670	7,829	8,004	8,175	8,347	8,491	8,613
May	7,293	7,426	7,877	8,217	8,581	8,772	8,872	8,979	9,152	9,436
Jun	8,476	8,885	9,097	9,541	9,800	9,816	9,906	10,519	10,699	10,902
Jul	9,243	9,440	9,752	10,261	10,488	10,836	10,989	11,157	11,296	11,619
Aug	8,995	9,220	9,459	10,003	10,270	10,484	10,741	10,837	11,071	11,371
Sep	7,939	8,281	8,607	8,988	9,230	9,254	9,527	9,735	10,005	10,202
Oct	7,426	7,667	7,728	7,899	8,240	8,480	8,630	8,741	8,819	9,070
Nov	8,154	8,442	8,877	9,149	9,306	9,371	9,533	9,705	10,018	10,098
Dec	8,451	8,641	9,083	9,261	9,434	9,790	9,881	9,996	10,161	10,254

[Reed C. Davis prepared this response and is the record holder. It has not been determined who will sponsor this response at hearing. Please contact Brian Dickman at 801-220-4975 to discuss this response.]

Summary - **3 Summer, 1 Winter CP**

Agrium
Pacificorp Cost Of Service By Rate Schedule
Agruim's Proposed 3 Summer 1 Winter Month Demand Allocator
12 Months Ending December 2006
MSP Protocol
8.07% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	01	Residential	29,653,369	8.08%	1.40	30,767,154	15,614,654	1,070,143	9,545,014	4,072,557	464,787	1,113,785	3.76%
2	36	Residential - TOD	21,362,235	9.72%	1.69	21,239,498	12,270,234	757,229	6,151,110	1,844,486	216,439	(122,737)	-0.57%
3	06	General Service - Large	18,609,425	14.03%	2.44	16,708,687	12,429,198	790,859	3,274,153	165,605	48,873	(1,900,738)	-10.21%
4	08	General Service - Medium Voltage	130,255	14.53%	2.52	116,006	87,946	5,648	21,854	292	266	(14,249)	-10.94%
5	09	General Service - High Voltage	5,061,143	15.91%	2.76	4,425,339	4,129,142	257,728	20,805	8,084	9,580	(635,804)	-12.56%
6	10	Irrigation	39,404,679	1.35%	0.23	50,904,132	33,757,077	2,609,271	13,973,191	436,972	127,622	11,499,453	29.18%
7	07,11,12	Street & Area Lighting	326,298	-17.98%	(3.12)	591,680	77,989	3,541	438,510	62,632	9,007	265,382	81.33%
8	12	Traffic Signals	15,526	16.19%	2.81	13,386	7,367	455	3,339	1,936	288	(2,140)	-13.78%
9	19	Space Heating	635,620	18.90%	3.28	514,868	359,391	21,365	117,896	13,451	2,766	(120,752)	-19.00%
10	23	General Service - Small	10,711,252	15.02%	2.61	9,360,572	5,450,579	350,524	2,758,560	701,970	98,939	(1,350,680)	-12.61%
11	SPC	Contract 1	3,998,852	5.68%	0.99	4,370,113	4,016,519	280,125	65,725	190	7,553	371,261	9.28%
12	SPC	Contract 2	48,668,727	2.45%	0.43	58,032,496	54,252,514	3,639,277	52,636	(4,496)	92,566	9,363,769	19.24%
13	Total	State of Idaho -	178,577,381	5.76%	1.00	197,043,931	142,452,609	9,786,165	36,422,792	7,303,679	1,078,686	18,466,550	10.34%

Footnotes :
Column C : Annual revenues based on 12-2006.
Column D : Calculated Return on Ratebase per 12-2006 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Idaho Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per the 12-2006 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per the 12-2006 Embedded COS Study.
Column H : Calculated Transmission Cost of Service at Jurisdictional Rate of Return per the 12-2006 Embedded COS Study.
Column I : Calculated Distribution Cost of Service at Jurisdictional Rate of Return per the 12-2006 Embedded COS Study.
Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per the 12-2006 Embedded COS Study.
Column K : Calculated Misc.Distribution Cost of Service at Jurisdictional Rate of Return per the 12-2006 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

Summary - Single CP

Agrium
Pacificorp Cost Of Service By Rate Schedule
Agrium's Illustrative Single CP Demand Allocator
12 Months Ending December 2006
MSP Protocol
8.07% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	01	Residential	29,653,369	7.51%	1.30	31,250,447	16,039,372	1,128,940	9,544,768	4,072,482	464,886	1,597,078	5.39%
2	36	Residential - TOD	21,362,235	12.18%	2.12	20,053,417	11,227,907	612,932	6,151,712	1,844,671	216,196	(1,308,818)	-6.13%
3	06	General Service - Large	18,609,425	17.78%	3.09	15,516,843	11,381,806	645,860	3,274,758	165,790	48,629	(3,092,582)	-16.62%
4	08	General Service - Medium Voltage	130,255	14.57%	2.53	115,909	87,861	5,636	21,854	292	266	(14,346)	-11.01%
5	09	General Service - High Voltage	5,061,143	14.73%	2.56	4,523,023	4,214,987	269,612	20,755	8,069	9,600	(538,120)	-10.63%
6	10	Irrigation	39,404,679	-0.32%	(0.06)	54,681,545	37,076,666	3,068,827	13,971,274	436,383	128,395	15,276,866	38.77%
7	07,11,12	Street & Area Lighting	326,298	-18.06%	(3.14)	576,460	64,613	1,689	438,518	62,635	9,004	250,162	76.67%
8	12	Traffic Signals	15,526	19.05%	3.31	12,717	6,778	374	3,340	1,936	288	(2,809)	-18.09%
9	19	Space Heating	635,620	20.29%	3.52	502,332	348,374	19,840	117,902	13,453	2,763	(133,288)	-20.97%
10	23	General Service - Small	10,711,252	17.47%	3.03	8,902,060	5,047,639	294,742	2,758,792	702,041	98,845	(1,809,192)	-16.89%
11	SPC	Contract 1	3,998,852	6.26%	1.09	4,306,179	3,960,334	272,347	65,757	200	7,540	307,327	7.69%
12	SPC	Contract 2	48,668,727	3.27%	0.57	56,602,998	52,996,273	3,465,366	53,361	(4,274)	92,273	7,934,271	16.30%
13	Total	State of Idaho -	178,577,381	5.76%	1.00	197,043,931	142,452,609	9,786,165	36,422,792	7,303,679	1,078,686	18,466,550	10.34%

Footnotes :
Column C : Annual revenues based on 12-2006.
Column D : Calculated Return on Ratebase per 12-2006 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Idaho Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per the 12-2006 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per the 12-2006 Embedded COS Study.
Column H : Calculated Transmission Cost of Service at Jurisdictional Rate of Return per the 12-2006 Embedded COS Study.
Column I : Calculated Distribution Cost of Service at Jurisdictional Rate of Return per the 12-2006 Embedded COS Study.
Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per the 12-2006 Embedded COS Study.
Column K : Calculated Misc.Distribution Cost of Service at Jurisdictional Rate of Return per the 12-2006 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

Agrium
Pacificorp Cost of Service by Rate Schedule
Agrium's Illustrative 3 Month Summer Peak Demand Allocator
12 Months Ending December 2006
MSP Protocol
8.07% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	01	Residential	29,653,369	9.89%	1.72	29,360,784	14,378,736	899,045	9,545,727	4,072,776	464,499	(292,585)	-0.99%
2	36	Residential - TOD	21,362,235	12.09%	2.10	20,095,727	11,265,088	618,079	6,151,690	1,844,664	216,205	(1,266,508)	-5.93%
3	06	General Service - Large	18,609,425	15.47%	2.69	16,217,815	11,997,820	731,140	3,274,402	165,681	48,772	(2,391,610)	-12.85%
4	08	General Service - Medium Voltage	130,255	15.80%	2.74	113,113	85,404	5,296	21,855	293	266	(17,142)	-13.16%
5	09	General Service - High Voltage	5,061,143	16.36%	2.84	4,390,647	4,098,655	253,507	20,822	8,090	9,573	(670,496)	-13.25%
6	10	Irrigation	39,404,679	-1.04%	(0.18)	56,580,224	38,745,224	3,299,818	13,970,311	436,088	128,784	17,175,545	43.59%
7	07,11,12	Street & Area Lighting	326,298	-18.06%	(3.14)	576,460	64,613	1,689	438,518	62,635	9,004	250,162	76.67%
8	12	Traffic Signals	15,526	17.14%	2.98	13,150	7,160	427	3,340	1,936	288	(2,376)	-15.30%
9	19	Space Heating	635,620	21.77%	3.78	489,881	337,432	18,325	117,908	13,455	2,761	(145,739)	-22.93%
10	23	General Service - Small	10,711,252	15.95%	2.77	9,177,897	5,290,044	328,300	2,758,652	701,998	98,902	(1,533,355)	-14.32%
11	SPC	Contract 1	3,998,852	6.16%	1.07	4,316,904	3,969,759	273,652	65,752	198	7,542	318,052	7.95%
12	SPC	Contract 2	48,668,727	3.82%	0.66	55,711,328	52,212,673	3,356,886	53,813	(4,135)	92,090	7,042,601	14.47%
13	Total	State of Idaho -	178,577,381	5.76%	1.00	197,043,931	142,452,609	9,786,165	36,422,792	7,303,679	1,078,686	18,466,550	10.34%

Footnotes :
Column C : Annual revenues based on 12-2006.
Column D : Calculated Return on Ratebase per 12-2006 Embedded Cost of Service Study
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