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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

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)
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CASE NO. PAC-E-11-12

DIRECT TESTIMONY OF RANDY LOBB
IN SUPPORT OF THE STIPULATION
AND SETTLEMENT

IDAHO PUBLIC UTILITIES COMMISSION

NOVEMBER 2, 2011

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1 Q. Please state your name and business address for the
2 record.

3 A. My name is Randy Lobb and my business address is
4 472 West Washington Street, Boise, Idaho.

5 Q. By who are you employed?

6 A. I am employed by the Idaho Public Utilities
7 Commission as Utilities Division Administrator.

8 Q. What is your educational and professional
9 background?

10 A. I received a Bachelor of Science Degree in
11 Agricultural Engineering from the University of Idaho in 1980
12 and worked for the Idaho Department of Water Resources from
13 June of 1980 to November of 1987. I received my Idaho
14 license as a registered professional Civil Engineer in 1985
15 and began work at the Idaho Public Utilities Commission in
16 December of 1987. I have conducted analysis of utility rate
17 applications, rate design, tariff analysis and customer
18 petitions. I have testified in numerous proceedings before
19 the Commission including cases dealing with rate structure,
20 cost of service, power supply, line extensions, regulatory
21 policy and facility acquisitions. My duties at the
22 Commission currently include case management and oversight of
23 all technical Staff assigned to Commission filings.

24 Q. What is the purpose of your testimony in this case?

25 A. The purpose of my testimony is to describe the

1 comprehensive settlement reach by most of the parties to the
2 case and explain Staff's support.

3 Q. Please summarize your testimony.

4 A. Staff supports the Stipulated Settlement proposing
5 a two-year rate plan that recovers a limited level of capital
6 expenditures and an increasing level of power supply costs
7 through a combination of base rate increases and Energy Cost
8 Adjustment Mechanism (ECAM) surcharges. Staff believes that
9 the comprehensive multi-year approach to resolving revenue
10 requirement represents a significantly better deal for
11 customers than could be achieved through either a one year
12 settlement, litigation of the current rate case, or
13 resolution of additional rate filings in 2012.

14 Staff further supports provisions of the
15 Stipulation that spread the revenue increase to customer
16 classes based in part on cost of service, generally increases
17 rate components on a uniform basis, addresses Populous to
18 Terminal transmission costs and provides resolution of
19 Monsanto interruptible credit valuation over the next two
20 years.

21 Q. How is your testimony organized?

22 A. My testimony is subdivided under the following
23 headings:

24 Stipulation Overview Page 3
25 The Settlement Process Page 6

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4	ECAM Issues	Page 18
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5 **Stipulation Overview**

6 Q. Would you please describe the terms of the
7 Stipulation?

8 A. Yes. The Stipulation specifies a two-year rate
9 plan increasing base rates by \$17 million (7.8%) in year one
10 and \$17 million (7.2%) in year two. The base rate increase
11 proposed to take effect on January 1, 2012 and January 1,
12 2013 consists of an \$11 million increase in Net Power Supply
13 Expenses (NPSE) and a \$6 million increase in non-NPSE each
14 year. This compares with the Company's original proposal of
15 increasing base rates by \$32.7 million (15%) in one year.

16 While the Stipulation represents a comprehensive
17 settlement, it does not provide agreement or acceptance of
18 specific revenue requirement adjustments or cost of service
19 methodology. However, it does incorporate all Commission
20 ordered adjustments from Case PAC-E-10-07, Order No. 32196.

21 The Stipulation specifically identifies base NPSE
22 in 2012 and 2013 for use in the ECAM including annual
23 Renewable Energy Credit (REC) revenue and establishes a load
24 change adjustment rate (LCAR) for the rate period. The
25 Stipulation also specifies how Monsanto and Agrium's share of

1 ECAM deferral balances will be amortized and collected
2 through 2014.

3 The Stipulation further specifies spreading the
4 revenue increase to customer classes based, in part, on the
5 Company's proposed Cost of Service (COS) Study. The parties
6 agreed to a 25% move toward COS each year of the rate plan as
7 part of the proposed settlement in this case without
8 accepting the Company's COS methodology for revenue
9 allocation in the future. The parties also agreed that rate
10 component changes within individual customer classes will be
11 prorated based on the original proposal filed by the Company.
12 However, customer charges for Residential Schedules 1 and 36
13 would remain unchanged.

14 Other terms in the Stipulation include: 1)
15 escalation in the current Monsanto curtailment product value
16 by █████ million each year of the two-year plan; 2) agreement
17 on the used and useful nature of the Populous to Terminal
18 Transmission line (including dismissal of the pending Idaho
19 Supreme Court appeal and excluding that portion of the line's
20 cost deemed plant held for future use (PHFU) from rate base
21 until January 1, 2014); 3) continued deferral of depreciation
22 expense associated with the Populus to Terminal transmission
23 line, pursuant to Order No. 32224; and 4) tracking Idaho's
24 share of the customer load control service credit through the
25 ECAM at the base amount of \$1,045,423 pending cost allocation

1 treatment of the dispatchable irrigation load control
2 program.

3 Finally, the Stipulation specifies a series of
4 collaborative meetings to address: 1) terms, conditions and
5 valuation of Monsanto's curtailment products; 2) cost of
6 service methodologies as applied to Monsanto and the
7 irrigation class and how said methodologies will be utilized
8 in the next general rate case; 3) terms of the irrigation
9 load control program for the 2013 season and beyond; 4)
10 hedging limits consistent with workgroup processes
11 established in Utah and Oregon.

12 The Stipulation specifies that Rocky Mountain Power
13 will not file another general rate case before May 31, 2013,
14 with new rates not effective prior to January 1, 2014. The
15 Stipulation does not prohibit the Company from revising rates
16 as part of its annual ECAM filing. The Stipulation is
17 attached as Staff Exhibit No. 101.

18 Q. How does the annual base revenue requirement
19 increase proposed in the Stipulation compare to the increase
20 originally proposed by Rocky Mountain Power?

21 A. As noted above, the Company proposed to increase
22 annual base electric revenue in 2012 by \$32.7 million or 15%
23 overall. The Stipulation increases annual base electric
24 revenue by \$17 million in 2012 or approximately 52% of the
25 Company's original request. The Company did not propose a

1 base rate increase in 2013 as part of its filing in this
2 case.

3 **The Settlement Process**

4 Q. Would you please describe the process leading to
5 the Stipulated Settlement?

6 A. Yes. The Company filed its rate application on May
7 27, 2011 and the Commission set a June 21, 2011 intervention
8 deadline. Parties ultimately approved for intervention
9 included the Monsanto Company, the Idaho Irrigation Pumpers
10 Association (IIPA), PacifiCorp Idaho Industrial Customers
11 (PIIC), the Community Action Partnership Association of Idaho
12 (CAPAI) and the Idaho Conservation League (ICL).

13 Once the parties to the case were determined, they
14 met to establish a schedule for production
15 requests/responses, pre-filed direct testimony, pre-filed
16 rebuttal testimony and the dates for the technical hearing.
17 The parties also established August 23, 2011 and September
18 22, 2011 as Settlement conference dates.

19 During the period prior to the first Settlement
20 conference, Staff thoroughly reviewed the Company's rate
21 filing and conducted onsite audit of Company expenses and
22 investments. In addition, Staff met informally with the
23 Company and other parties to discuss a variety of issues in
24 preparation for settlement negotiations. Issues discussed
25 included potential expense adjustments, increasing NPSE and

1 associated ECAM rate impacts, cost of service, revenue spread
2 and the valuation of curtailment products.

3 The first Settlement conference held in August was
4 attended by all the parties in the case and focused primarily
5 on revenue requirement. Return on Equity, power supply
6 expenses, wages and benefits, risk management and wheeling
7 revenues were just a few of the revenue requirement issues
8 presented and discussed. The parties discussed revenue
9 requirement adjustments and stated their positions on issues
10 ranging from jurisdictional and class cost of service cost
11 allocation, to rate design and low income weatherization
12 programs. There was no discussion of a multi-year rate plan
13 and Settlement was not achieved at the first conference.

14 Q. Did additional informal discussions take place
15 among the parties prior to the second Settlement conference?

16 A. Yes. As a result of discussions during the initial
17 Settlement conference, it became apparent to the parties that
18 NPSE decisions in this case had multi-year impact through the
19 ECAM. The parties began to analyze the combined base and
20 ECAM rate impact on the various customer classes through the
21 year 2014. Prior to the September Settlement conference, the
22 parties circulated numerous multi-year revenue proposals so
23 all participants could evaluate and agree on how rates would
24 likely change over the period under difference scenarios.

25 On September 22, a proposed two-year rate plan

1 consisting of a combination of NPSE and non-NPSE base revenue
2 increases was presented. Negotiations ensued on the level of
3 increase each year, the split between NPSE and non-NPSE
4 revenue, how revenue spread to customer classes would occur
5 and how ECAM impacts could be mitigated. No Settlement was
6 reached during the second Settlement conference.

7 Q. How did the parties ultimately agree on the terms
8 in the Stipulation?

9 A. Informal discussions among the conference
10 participants continued after the second conference which
11 ultimately led to agreement in principal regarding the two
12 year revenue requirement, revenue spread to customer classes
13 and ECAM rate mitigation. Significant negotiation also
14 occurred over language in the Stipulation regarding treatment
15 of the Populous to Terminal transmission line and the scope
16 of additional discussions that must occur between the Company
17 and interested parties before the next general rate case. As
18 a result of much discussion, negotiation and compromise, all
19 parties to the case except CAPAI signed the Stipulation. ICL
20 officially withdrew as an Intervenor in the case on October
21 14, 2011.

22 **Staff Evaluation**

23 Q. How did Commission Staff evaluate the Stipulation
24 to determine that it was reasonable?

25 A. There were several steps taken by Staff in this

1 case to fully evaluate the Stipulation and conclude that it
2 was reasonable. The focus of the evaluation was to assure
3 the best deal for customers. The first step was to identify
4 revenue requirement adjustments based on a thorough review of
5 the Company's filing and an extensive audit of Company
6 financial records. The identified adjustments reducing the
7 requested increase must be supported by evidence on the
8 record and have a reasonable chance of being accepted by the
9 Commission.

10 The second step was to determine if the identified
11 adjustments removed costs from rate recovery or simply
12 removed costs from base rate recovery. For example, NPSE
13 adjustments might remove costs from base rate recovery only
14 to have them tracked for later recovery through the ECAM
15 mechanism.

16 Q. What adjustments did Staff identify and how were
17 they categorized?

18 A. Staff identified a broad range of adjustments
19 starting with adjustments previously approved by the
20 Commission in the Company's last rate case, Case No.
21 PAC-E-10-07. These adjustments included a lower ROE than
22 that proposed by the Company in this case, continued removal
23 of Populus to Terminal transmission costs until the next rate
24 case, removal of salary increases and reduction in coal
25 stockpile costs. Other identified adjustments included

1 Klamath Falls expenses, coal settlement costs, property
2 taxes, abandoned project costs, a variety of power supply
3 expenses and a number of other miscellaneous costs. Staff's
4 proposed adjustments, if fully accepted by the Commission,
5 would have reduced the Company's revenue increase request by
6 approximately \$14.3 million, \$5 million of which were power
7 supply costs subject to recovery through the ECAM.

8 Q. Did other parties to the case propose revenue
9 requirement adjustments?

10 A. Yes. Other parties suggested adjusting power
11 supply costs, ROE, wheeling revenues, hedging expenses and
12 REC revenues. However, most of these suggestions were
13 already incorporated in Staff adjustments, previously decided
14 by the Commission, or in Staff's view, were without
15 sufficient support. Consequently, Staff evaluated the
16 revenue requirement settlement at this point primarily based
17 on Staff adjustments alone.

18 Q. Did Staff consider proceeding to hearing rather
19 than settling the case?

20 A. Yes. Staff considered proceeding to hearing with
21 the identified adjustments. In this case, Staff was not
22 confident that it could successfully defend all of the
23 identified adjustments on the record in the face of rebuttal
24 testimony provided by the Company.

25 While the Commission makes the final decision on

1 Company revenue requirement based on the record at hearing,
2 it is the parties to the case that make revenue requirement
3 adjustment recommendations for the Commission to consider.
4 The outcome at hearing in terms of revenue requirement must
5 therefore be evaluated based on both the adjustments to the
6 Company's revenue request that are presented on the record
7 and how the Commission might decide each adjustment.

8 In Staff's opinion, the best case scenario at
9 hearing would have been an increase in the range of \$18.5
10 million (8.5%) achieved in part by pushing \$5 million in NPSE
11 to the ECAM for later recovery.

12 Q. Why did Staff pursue settlement on a multi-year
13 basis?

14 A. Staff determined that approximately \$17 million of
15 the Company's requested \$32.7 million increase in this case
16 was for increased NPSE that is already accumulating in the
17 ECAM deferral balance for recovery starting in April of next
18 year. Failure to recover legitimate NPSE in base rates as
19 part of this case pushes recovery of the expenses to the ECAM
20 in 2013. Clearly, cost recovery decisions in this case have
21 a multi-year impact on customer rates.

22 Q. What are the reasons for the NPSE increase?

23 A. The primary reason for the NPSE increase in this
24 case is the declining revenue from surplus electricity sales
25 used to offset system power supply expenses and to a lesser

1 extent, expiration of low-cost power purchase agreements and
2 increasing coal costs. Surplus sales revenue has declined
3 due to reduced market value of electricity caused by
4 declining natural gas prices and increasing surplus wind
5 generation. While surplus sales volume has increased and the
6 cost to fuel natural gas generating plants has decreased, it
7 has not been enough to offset the decline in surplus sales
8 revenue.

9 NPSE has been characterized as the utility's power
10 bill that is passed on to customers. Historically, it has
11 been very difficult to remove expenses in this category from
12 both base rate and ECAM recovery.

13 Q. How has NPSE changed over the last few years and
14 what is the forecast for next year?

15 A. In Case No. PAC-E-10-07, the Company proposed an
16 increase in Idaho NPSE from \$66.1 million to \$69.2 million.
17 The Commission approved Idaho NPSE of approximately \$66.2
18 million in that case. In this case, the Company requested
19 Idaho NPSE of approximately \$82.8 million or approximately
20 \$17.7 million more than currently in base rates. In its most
21 recent rate filing in the State of Utah, the Company
22 forecasted NPSE through year end 2012 to be approximately
23 \$1.521 billion on a system basis or approximately \$98.4
24 million in Idaho. This amount is approximately \$15.6 million
25 more in NPSE than the Company requested in this case. The

1 Company indicates that NPSE should level off somewhat after
2 2012. In the meantime, the difference between NPSE recovered
3 in base rates and NPSE actually incurred will be recovered
4 through the ECAM.

5 Q. How does the multi-year settlement address the NPSE
6 issue?

7 A. The multi-year settlement spreads recovery of
8 increasing NPSE over three years by combining the proposed
9 \$22 million in NPSE base rate increases with the existing \$10
10 million of NPSE currently recovered through the ECAM. By the
11 end of the rate plan in 2013, annual NPSE recovery in Idaho
12 will total approximately \$98.2 million with the potential for
13 ECAM rate reduction. This will allow customers to better
14 manage the impact of increasing power supply costs over time.

15 Q. How did Staff evaluate the non-NPSE increases
16 specified in the Stipulation?

17 A. Unlike NPSE costs, non-NPSE costs can only be
18 recovered through base rates. Therefore, Staff focused on
19 achieving a lower level of recovery for this category of
20 costs and a better deal for customers through settlement than
21 could be achieved through the hearing process.

22 The Company requested an increase of approximately
23 \$16 million in non-NPSE in this case. Based on Staff's
24 identified adjustments for this category of costs, the best
25 outcome that could be expected at hearing was an increase of

1 approximately \$6.7 million. The Stipulation proposes an
2 increase of \$6 million or less than 38% of the amount
3 originally requested by the Company. This stipulated amount
4 is equivalent to the Commission accepting every adjustment
5 proposed by the Staff plus an additional \$700,000.

6 Q. How did Staff determine that the rate increase
7 proposed in the second year of the Stipulation was
8 reasonable?

9 A. Staff evaluated the rate increase proposed for the
10 second year based on the rate request made by the Company
11 last year, the overall rate request made this year and the
12 likelihood that the Company would make a similar rate
13 increase request next year. Last year the Company requested
14 an increase of \$27.7 million (13.7%) of which \$24.6 million
15 was for non-NPSE. The Commission approved an increase of
16 \$14.35 million (7.07%) all of which was non-NPSE. In this
17 case, the Company requested an increase of \$32.7 million
18 (15%) of which \$16 million was non-NPSE.

19 Using a 2012 forecasted test year, the Company
20 filed in the State of Utah to increase NPSE (over Company
21 proposed 2011 levels) by approximately \$15.6 million on an
22 equivalent Idaho jurisdictional basis. The proposed rate
23 base increase in the Utah filing was approximately \$153
24 million on an Idaho equivalent basis. The non-NPSE increase
25 associated with just the return on the increased rate base is

1 approximately \$12 million in Idaho. Absent approval of the
2 Settlement, the Company could and likely would file for a
3 rate increase in 2012 exceeding \$30 million, with more than
4 \$12 million of the requested increase for non-NPSE. The
5 Stipulation proposes a non-NPSE increase that is less than
6 50% of that level.

7 Q. Could you please summarize Staff's support of the
8 Stipulation with regard to the revenue requirement increase
9 over the two-year period?

10 A. Yes. Because actual power supply expenses are
11 tracked for recovery through the ECAM, customers can pay them
12 now through base rates or pay them later through the ECAM.
13 The \$22 million NPSE base rate increase specified in the
14 Stipulation, when combined with expenses currently collected
15 through the ECAM, will reasonably spread recovery of expected
16 power supply costs through 2014.

17 Staff believes the \$12 million non-NPSE increase
18 specified in the Stipulation represents a fraction of the
19 non-NPSE that the Company has requested in this case and
20 would request in a filing next year. Staff maintains that
21 the \$6 million non-NPSE increase this year is only 38% of the
22 Company's request and a better deal for customers than could
23 be achieved at hearing. Staff further maintains that the \$6
24 million increase in non-NPSE in 2013 is less than 50% of what
25 the Company would otherwise request in a filing next year.

1 The Stipulation prohibits the Company from any further base
2 rate increases until January 1, 2014.

3 **Cost of Service**

4 Q. Could you please describe the Stipulation with
5 respect to customer class cost of service (COS) and revenue
6 spread?

7 A. Yes. While the parties to the Stipulation agreed
8 to a revenue spread in this case based on the Company's
9 proposed class COS study, they did not agree to accept the
10 methodology in future rate cases. The Stipulation specifies
11 that the revenue spread to customer classes in each year of
12 the rate plan will include a 25% move toward the Company's
13 proposed COS in this case.

14 The resulting revenue spread to the various
15 customer classes in year one of the rate plan range from an
16 increase of 5.88% for Schedule 1 residential customers to
17 8.91% for Irrigators, Agrium and the Monsanto Company. Year
18 two increases range from 5.43% for residential customers to
19 8.25% for Irrigators, Agrium and the Monsanto Company. The
20 revenue spread and associated increases for each class, in
21 each year of the rate plan, is shown on Attachment 1 to the
22 Stipulation.

23 Staff believes that the 50% move toward COS over
24 two years is a reasonable compromise that balances the need
25 for each customer class to pay its fair share while

1 mitigating an even greater rate impact that would otherwise
2 occur with a full COS move. The compromise also allows
3 parties to accept some COS responsibility without accepting a
4 COS methodology.

5 **Rate Design**

6 Q. How are individual rate components proposed to
7 change under the Stipulation?

8 A. The Parties agreed to accept, for the purposes of
9 this case, the Company's proposals to adjust rate components
10 within each rate schedule with the exception of customer
11 charges in Residential Schedules 1 and 36. Customer charges
12 for these schedules will remain unchanged at \$5 and \$14 per
13 month, respectively.

14 Demand charges for Schedules 6, 6A, 9 and 10 will
15 increase each year based in part on cost of service and
16 prorated to reflect the revenue increase assigned to each
17 customer class. Other rate components will increase
18 uniformly reflecting the overall increase in class revenue
19 requirement. Staff believes that the stipulated rate changes
20 are reasonable in allowing customer charges to remain stable,
21 demand charges to generally reflect cost of service and for
22 other charges including energy to reflect the class revenue
23 requirement increase.

24 Schedule 1 residential customers using the annual
25 monthly average of 837 kWh per month will see a monthly base

1 rate increase of \$5.47 and \$4.20 in summer and winter,
2 respectively, in the first year. Customers will see an
3 additional increase of \$5.36 and \$4.10 per month in summer
4 and winter, respectively, in the second year. A monthly
5 billing comparison for Residential Schedule 1 at various
6 monthly consumption levels is shown in Staff Exhibit No. 102.

7 **ECAM Issues**

8 Q. What ECAM issues are addressed in the Stipulation?

9 A. Besides specifying the ECAM level of system NPSE in
10 base rates for 2012 and 2013 at \$1.205 billion and \$1.385
11 billion, respectively, the Stipulation specifies the ECAM
12 level of system Renewable Energy Credits (RECs) included in
13 rates at \$78.8 million and establishes the ECAM LCAR at \$5.47
14 per Mwh through 2013. The Stipulation also establishes the
15 level of Idaho allocated Irrigation Load Control program
16 credits at \$1.05 million to be tracked through the ECAM
17 pending resolution of system allocation issues.

18 Q. Could you please explain Staff's support for these
19 ECAM terms specified in the Stipulation?

20 A. Yes. Staff supports the system NPSE levels
21 specified in the Stipulation for 2012 and 2013 because they
22 are consistent with stipulated NPSE revenue requirement
23 increases for those years. These levels must be specified in
24 order for the ECAM to work properly. The ECAM REC revenue
25 levels are as filed by the Company and within a reasonable

1 range of expected revenue on an annual basis. Actual annual
2 revenue above or below this level will be tracked through the
3 ECAM and trued up each year.

4 The specified LGAR of \$5.47 per Mwh was approved by
5 the Commission as part of Case No. PAC-E-10-7 and is
6 currently used in the ECAM. Staff supports continued use of
7 the previously approved LGAR level through 2013.

8 The Irrigation Load Control program credit level of
9 \$1.05 million specified in the Stipulation is consistent with
10 Irrigation program costs currently allocated to Idaho. Staff
11 agrees that the ability to track irrigation program costs
12 assigned to Idaho through the ECAM during the period of the
13 rate plan is consistent with the Stipulation approved by the
14 Commission in Case No. PAC-E-11-06. The Multi-State Process
15 (MSP) on jurisdictional allocations will determine during the
16 rate plan period if Idaho Irrigation Load control costs will
17 be accepted by other state jurisdictions as a system
18 resource.

19 Q. Are there any other ECAM issues specified in the
20 Stipulation?

21 A. Yes. The Stipulation provides for multi-year
22 amortization of ECAM costs assigned to Agrium and the
23 Monsanto Company. Monsanto and Agrium are not currently
24 subject to ECAM rates. However, these customers will be
25 subject to the ECAM starting in 2012. Consequently, they

1 will experience a base rate increase on January 1, 2012 and a
2 significant ECAM rate increase on April 1, 2012 as they
3 become subject to the tracking mechanism. This will occur
4 again in 2013. To mitigate the rate impact of both the base
5 rate increase and the ECAM increase, the Stipulation provides
6 for amortization of ECAM balances subject to recovery from
7 the two customers. 2012 (2011 deferrals) ECAM balances will
8 be amortized through 2014, 2013 (2012 deferrals) ECAM
9 balances will be amortized through 2015 and 2014 (2013
10 deferrals) ECAM balances will be amortized over two years
11 through 2016.

12 Staff fully supports amortization of the ECAM
13 deferral balance for these customers to mitigate the much
14 larger rate impact that would otherwise occur. Staff notes
15 that agreement to amortize ECAM expense recovery for these
16 customers has no impact on other Rocky Mountain Power
17 customers in Idaho.

18 **Other Items**

19 Q. Would you please describe the terms in the
20 Stipulation with regard to the Populous to Terminal
21 transmission line.

22 A. Yes. The parties agreed as part of the Stipulation
23 in this case that the Populous to Terminal transmission line
24 is currently, fully used and useful. However, the parties
25 also agree that the portion of the transmission line deemed

1 plant held for future use in Case No. PAC-E-10-07 shall not
2 be included in rates until on or after January 1, 2014. The
3 parties further agree that the Staff and the Company will
4 file a motion to suspend the Appeal now pending in the Idaho
5 Supreme Court, docketed as Case No. 38930-2011. The parties
6 also agree that the Company will file a stipulation for
7 dismissal of the appeal with each party to bear its own costs
8 upon receipt of a final order from the Commission approving
9 this Stipulation. Consistent with the terms of the
10 Stipulation, the Company and Staff filed the motion to
11 suspend the appeal on October 25, 2011.

12 The Stipulation also directs the Company to
13 continue deferring depreciation expense associated with the
14 Populus to Terminal transmission line, pursuant to Order No.
15 32224, until it is included in rates on or after January 1,
16 2014 and that the accumulated deferral balance will be
17 amortized over three years from the date the costs are
18 included in rates.

19 Q. Why did Staff agree to these terms?

20 A. Staff agreed to the terms in the Stipulation as a
21 compromise in order to achieve a comprehensive settlement in
22 this case on revenue requirement. Staff believed that it
23 could agree to the position that the Populous to Terminal
24 transmission line was now fully used and useful as long as
25 that portion of the transmission line deemed plant held for

