I. INTRODUCTION

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Q. PLEASE STATE YOUR NAME, POSITION AND YOUR BUSINESS ADDRESS.

A. My name is Daniel E. Gimble. I am a special projects manager with the Office of Consumer Services (Office). My business address is 160 E. 300 S., Salt Lake City, Utah.

Q. PLEASE DISCUSS YOUR EDUCATION AND QUALIFICATIONS.

A. I have a B.A. degree with honors in economics and history from Western Michigan University. I also have an M.A degree in economics from the same university. I completed course work towards a Ph.D. in economics at the University of Utah. In 1987, I joined the Utah Public Service Commission (Commission) Staff and in 1990 was hired by the Office. In my time with the Office, I have worked in various capacities and have been a manager since 2003.

Q. HAVE YOU APPEARED AS A WITNESS BEFORE THIS COMMISSION IN PRIOR CASES INVOLVING ROCKY MOUNTAIN POWER OR OTHER UTILITIES?

A. Yes. Since 1991 I have testified numerous times in major cases involving Rocky Mountain Power (Company) and other utilities providing service in Utah. These cases include general rate cases, merger and acquisition dockets, excess net power costs, avoided cost rates, gas pass-through proceedings, and the sale of Qwest's Dex (Yellow Pages) asset. I most recently appeared before the Commission in Docket 09-035-23, testifying in support of the Office's positions on cost-of-service, rate spread and rate design.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN PHASE I OF THIS DOCKET?

A. No, this is my first time filing testimony in this proceeding.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN PHASE II OF THIS PROCEEDING?

A. My testimony addresses the issue of market reliance[1] as it relates to the design and implementation of an Energy Balancing Account Mechanism (ECAM) for Utah. In connection with the issue of market reliance, my testimony discusses:

- An overview of the market reliance issue;
- The Company's current market reliance strategy, particularly in the 2012-2014 bridging period;[2]
- The supporting evidence and independent verification of the assumptions underlying the Company's market reliance strategy;
- Guidance and concerns expressed by the Commission regarding market reliance; and
- Recommendations of the Office with respect to the Company's market reliance strategy separately and in relationship to its ECAM proposal.

Q. IS THE OFFICE SUBMITTING DIRECT TESTIMONY OF OTHER WITNESSES IN PHASE II OF THIS PROCEEDING?

A. Yes. Mr. Paul Wielgus and Dr. Lori Schell are filing testimony on behalf of the Office addressing hedging concepts and the Company's revised gas hedging framework. In my testimony I present the recommendations contained in the testimony of all Office witnesses relating to the areas of hedging practices and market reliance.

[1] Market Reliance refers to the Company's use of short-term market products ranging between one to three years, such as wholesale market purchases or power exchanges, to meet load requirements, especially in the third quarter peak period. The Company interchangeably refers to these types of market products as short-term resources or front office transactions in its 2008 IRP Update. I will use this term, market reliance, as a convenient reference for this concept throughout this testimony.

[2] Action Item 2 in the 2008 IRP Update refers to a "bridging strategy" to support the deferral of intermediate and baseload resources until summer 2015 in the eastern control area. Throughout my testimony I refer to bridging strategy or "bridging period" in reference to this deferral of intermediate and baseload resources to 2015.

Q. PLEASE SUMMARIZE THE OFFICE'S RECOMMENDATIONS.

A. In deciding whether some form of ECAM is in the public interest, the Commission should do the following,

- Act upon the recommendations relating to the Company's hedging practices proposed by the Office's experts, Mr. Wielgus and Dr. Schell, that the Company should:

  (1) Perform a thorough analysis of all costs associated with its hedging practices (Wielgus);
  (2) Evaluate the use of options to reduce price volatility (Wielgus);
  (3) Evaluate the cost and benefit of the partial leveling of rates that results from hedging natural gas compared to acquiring more non-gas resources instead of gas resources. (Wielgus);
  (4) Compare the value of its hedging practices with other ways to address price volatility, such as the Enterprise Risk Management (ERM) approach (Wielgus);
  (5) Provide ample opportunity for affected parties to have input into the process of evaluating the Company's hedging practices (Wielgus);
  (6) Reduce its volume-based hedge targets to reflect historical system balancing levels (Schell);
  (7) Re-examine the acceptable range of TEVaR levels (Schell).

  Neither natural gas hedging costs nor natural gas fuel costs should be allowed in an ECAM design until this evaluation has been completed. If customers are going to be required to bear the risks of natural gas cost fluctuation, they should have input into establishing appropriate hedging strategies and associated costs.

- Require the Company to perform a comprehensive analysis justifying the adequacy and depth of the western market to support the projected volumes and prices associated with FOTs, as indicated in its current resource plan. This justification should include independent validation of the Company's market assessment. This analysis should be required before the costs associated with market purchases are allowed in any ECAM design and also required on an ongoing basis in all future IRPs.

- Consider developing and applying limits on the volume of FOTs for purposes of inclusion in an ECAM.

II. OVERVIEW OF THE MARKET RELIANCE ISSUE

Q. PLEASE DESCRIBE THE BACKGROUND OF THE MARKET RELIANCE ISSUE.

A. Michele Beck, on behalf of the Office in Phase I of this case, raised the issue of how the implementation of an ECAM would shift the risks associated with a planning strategy that relied too heavily on market purchases from the Company to consumers. In its Report and Order in Phase I issued February 9, 2010, the Commission specifically directed parties to address this issue in Phase II by stating "we would like to see the two issues raised by the Office of Consumer Services addressed: namely, is the company's use of natural gas hedging and the level of and reliance on market energy affected by the use of an ECAM?"

Q. HAS THE OFFICE PREVIOUSLY RAISED THESE TYPES OF ISSUES IN OTHER FORUMS?

A. Yes. The Office (and other parties) has raised concerns about the level of the Company's reliance on market purchases in the Company's IRP filings for many years.

Q. HOW DOES THE OFFICE PROPOSE ADDRESSING THE ISSUE IN THIS PHASE OF THE CASE?

A. The Office recommends, and puts forth in this testimony, an approach as follows:

- First, examine the Company's current market reliance strategy.
- Second, evaluate whether the strategy has been well supported with evidence and whether the underlying assumptions can be independently verified.
- Third, examine whether the strategy is consistent with Commission guidance.
- Fourth, determine how much of these costs are appropriate to be passed through to customers in establishing a potential ECAM design.

III. COMPANY'S CURRENT LEVEL OF MARKET RELIANCE

Q. WHAT SOURCE DID THE OFFICE USE IN EVALUATING THE COMPANY'S CURRENT LEVEL OF MARKET RELIANCE?

A. The Office reviewed the Company's 2008 IRP Update, which was filed with the Commission on March 31, 2010. This is the most current source of resource planning assumptions and information.

Q. PLEASE SUMMARIZE THE SALIENT CHANGES IN THE IRP UPDATE AS COMPARED TO THE EARLIER 2008 IRP.

A. Five significant changes are identified in 2008 IRP Update – changes that result in a revised action plan.[3] These changes are as follows:

- Peak and energy load forecasts have been adjusted downward for Oregon and Utah in the near-term and over the entire 10-year planning horizon for Wyoming. This results in PacifiCorp's system remaining slightly resource surplus through 2011, and reduces the

[3] 2008 IRP Update, Table 6.1. Table 6.1 compares the updated action plan to the 2008 IRP action plan filed about one year ago.

2012 system resource deficit from approximately 1,900 MWs to 1,264 MWs.[4]

- The need for a large, eastside combined cycle plant is deferred from 2014 to 2015 and the gas peaker anticipated to be needed in 2016 is supplanted by a large, eastside combined cycle plant to be in-service in 2018.
- New wind resources are eliminated for the 2012-2016 period. In addition, the total amount of new wind resources over the 2009-2019 period is reduced by 161 MWs in the IRP Update.[5]
- The 200 MW expansion of the Utah Cool Keeper Demand-Side Program is reduced to a modest increase of 30 MW over the ten-year planning period.
- New wholesale sales contracts appear in the Company's load and resource balance table in the years 2012 and 2013. These appear to be separate one-year sales contracts at 250 MW (2012) and 300 MW (2013).

Q. WHAT ARE THE IMPLICATIONS OF THE REVISED ACTION PLAN IN THE 2008 IRP UPDATE FOR THE ACQUISITION OF SHORT-TERM VERSUS LONG-TERM RESOURCES?

A. According to Table ES.1, which is labeled as the Company's "2010 Business Plan Portfolio" in the IRP Update, the Company is planning to heavily rely on annual short-term market purchases to meet load growth throughout the ten-year planning period. Only two major resources – combined cycle "proxy" plants at the Lakeside and Currant Creek sites – are added over the planning period.[6] Based on the resource numbers

[4] Table 3.9 – Capacity Load and Resource Balance (12% PRM). According to Table 3.9, the System Position is "Resource Deficit" by 1,264 in 2012. This resource deficit is projected to rapidly increase to 2,189 MWs by 2014.

[5] 447 MWs of eastside wind resources are acquired or built in the 2011-2012 period and the next wind resource (eastside at 160 MWs) is delayed to 2017. A comparison of Table 9.1 of the 2008 IRP with Table ES.1 in the 2008 IRP update shows a total reduction in wind resources from 1,048 MWs to 887 MWs over the 2009- 2019 period.

[6] Lakeside 2 and Currant Creek 2 proxies are scheduled for 2015 and 2018, respectively.

indicated in Table ES.1 of the IRP Update, my Table 1 (below) compares annual long-term resource additions with short-term resource additions. Table 1 shows that in the 2012-2019 period, the Company plans to rely on annual short-term resources to meet between 47% and 91% of its annual resource needs and that this reliance on the short-term market is most pronounced in the 2012-2014 period.

Table 1

Year	2012	2013	2014	2015	2016	2017	2018	2019
LTR[7]	344	149	125	708	136	251	721	292
STR[8]	604	932	1,223	794	923	958	636	794
Total	948	1,081	1,348	1,503	1,059	1,208	1,357	1,087

Q. THE LAST YEAR OF THE BRIDGING PERIOD IS 2014. WHAT IS THE COMPANY'S SYSTEM LOAD AND RESOURCE POSITION IN 2014?

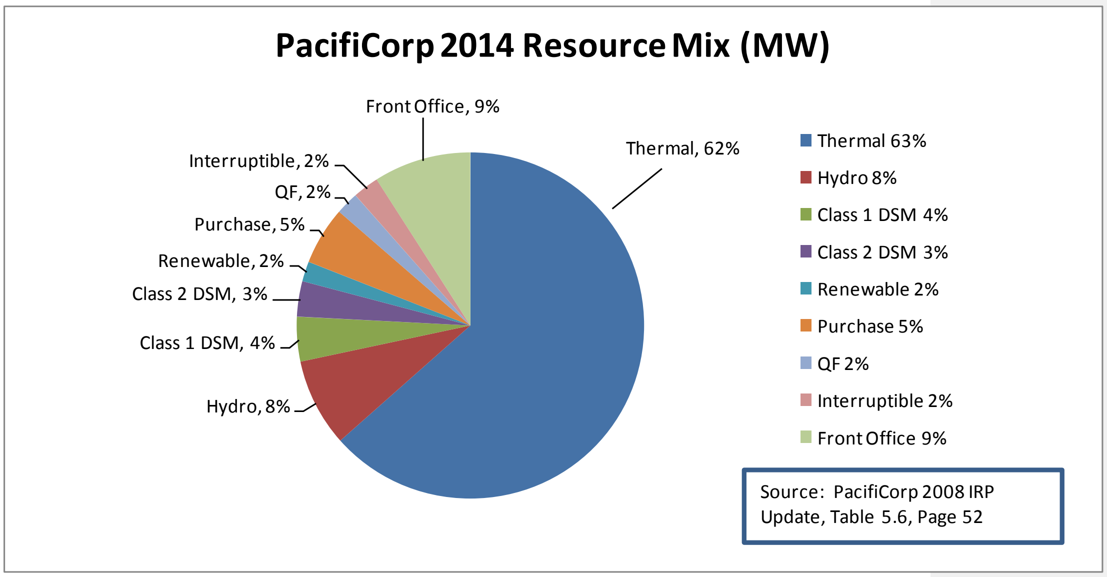
A. In Table 3.9 of the 2008 IRP Update (pg. 33), the Company reports a system resource deficit position of 2,198 MW in 2014. This represents an increase in the system deficit position from 1,264 MW in 2012 to 2,198 MW in 2014. However, I believe it is very important for the Commission to understand that the eastside of the system is more severely resource deficit than the westside throughout the 2012-2014 bridging period. In 2014, the eastside resource deficit position has increased to 1,680 MW out of the 2,198 MW system deficit.[9]

[7] Long-Term Resources.
[8] Short-Term Resources. Short-term resources represent front office transactions that the Company typically enters into for a period of 1-3 years.
[9] Table 5.6 of the IRP Update shows that approximately half of the eastside resource shortfall is resolved via the transfer of 830 MW of power from the westside to the eastside of the system. This is presumably the transfer of power from Bridger and other resources made available through existing and possibly incremental transmission capacity (See 2008 IRP Update, Action Item 2, last bullet addressing incremental transmission). A substantial portion of the remaining eastside resource deficit position is met with 519 MW of front office transactions.

Q. IN 2014, WHAT PERCENTAGE OF THE TOTAL RESOURCE MIX DO SHORT-TERM RESOURCES REPRESENT IN COMPARING THE 2008 IRP UPDATE TO THE 2008 IRP?

A. From a capacity standpoint, short-term resources in the 2008 IRP Update are approximately 9.0% of the Company's overall resource mix in 2014.[10] The 9.0% level represents an increase over the 6.8% reported in the 2008 IRP.[11] While short-term resources are not a significant component of the Company's total resource mix relative to coal or gas combined-cycle resources, they are proportionately higher in 2014 because of the deferral of the Lakeside 2 proxy from 2014 to 2015 and changes in assumptions relating to wind and demand-side management resources. PacifiCorp's updated resource mix for 2014 is illustrated in Table 2 below.

Table 2



[10] Table 5.6 of the 2008 IRP Update indicates 1,223 MW of front office transactions are needed in 2014 and that total resources are 13,500 MW in 2014. 1,233 MW/13,500 MW = 9.05%.

[11] 2008 IRP, pg. 249.

Q. IF THE 2008 IRP UPDATE ACTION PLAN STILL TARGETED A 2014 IN-SERVICE DATE FOR THE LAKESIDE 2 PROXY RESOURCE, HOW WOULD THAT IMPACT THE AMOUNT OF SHORT-TERM RESOURCES NEEDED IN 2014?

A. Maintaining a 2014 in-service date for the 607 MW Lakeside 2 proxy would effectively cut the reported 1,233 MW need for short-term resources in half. Thus, the percentage of short-term resources would fall from approximately 9.0% to 4.5% in 2014.

Q. WHAT IS THE IMPETUS DRIVING THE SIGNIFICANT CHANGES IN THE 2008 IRP UPDATE THAT YOU DESCRIBE ABOVE?

A. The 2008 IRP Update is closely linked with management's 2010 business planning process wherein management re-evaluated resource needs given lower near-term load forecasts and recessionary economic conditions. On Page 15 of the 2008 IRP Update the Company states,

> "A main finding of the 2010 business planning process was that given the current load forecast and the economic turndown, the operating and capital budgets supporting the 2009 business plan would not maintain a capital structure that is optimal for both customers and the Company, and would increase rate pressure on customers. For example, assessment of the initial projected capital budget with resource acquisitions and resultant cash flows indicated difficulty in maintaining current debt ratings. As a consequence, PacifiCorp reexamined the need and timing for capital investments and, where appropriate and feasible, the business plan eliminates or defers investments. The revised capital budget included expenditure reductions on the order of $3.5 billion in the early years of the plan, relative to the budget established for the 2009 business plan."

Q. WHAT CONCERNS DOES THE OFFICE HAVE WITH THE 2010 BUSINESS PLAN PORTFOLIO AS IT RELATES TO THE COMPANY'S REQUEST FOR IMPLEMENTATION OF AN ECAM IN UTAH?

A. The Office is concerned that if an ECAM is approved and implemented, then resource deferrals included in the 2010 Business Plan Portfolio expose Utah customers to the risk associated with market price volatility, poor hydro conditions, and a quicker recovery of loads from the economic recession than forecasted by the Company. A confluence of rising market prices, prolonged drought conditions and demand recovery above forecasted levels would likely create significant upward pressure on net power costs, especially in the 2012-2014 bridging period when PacifiCorp's 2010 Business Plan calls for a heavy reliance on short-term market purchases to meet load requirements. Thus, the Company's proposal to design (2010) and implement (2011) an ECAM arrives just in advance of the time PacifiCorp's system is expected to be resource deficit and could result in shifting more market reliance risk from Company management to Utah customers. Thus, it is critically important that the Company supports and verifies the assumptions underlying its market reliance strategy.

IV. <u>SUPPORTING EVIDENCE AND INDEPENDENT VERIFICATION</u>

Q. DID THE COMPANY PRESENT INFORMATION IN ITS 2008 IRP UPDATE THAT SUPPORTS THE ASSUMPTIONS UNDERLYING ITS MARKET RELIANCE STRATEGY?

A. In the IRP Update the Company presents updated gas and power market price forecasts based on its September 2009 natural gas price curve and its September 30, 2009 official forward price curves. The September 2009 natural gas price forecast is similar to the October 2008 forecast used in preparing the 2008 IRP, for the 2012-2014 period.[12] After 2014 the

[12] 2008 IRP Update, Figure 4.1, pg. 37

September 2009 forecast is much lower than the October 2008 forecast through the year 2030. Similarly, the Company's September 2009 power market price forecasts for Palo Verde (Annual Flat and Annual Heavy Load Hour Prices) and Mid-Columbia (Annual Flat Prices) are close to the prices forecasted in October 2008 for the 2012-2014 period. After 2014 the September 2009 market price forecasts are much lower than the October 2008 forecasts for the Palo Verde and Mid-Columbia markets. Thus, the projected gas and market prices in the near-term are similar in both forecasts.

Q. DID THE OFFICE REQUEST THAT THE COMPANY PROVIDE ITS MOST RECENT GAS AND MARKET PRICE FORECASTS?

A. Yes. In response to OCS DRs 8.1 – 8.3, the Company provided its March 2010 gas and market price forecasts. These March 2010 forecasts show that the Company anticipates both gas and market prices to be significantly lower in the 2012-2016 period compared to the September 2009 forecasts. After 2016, the March 2010 gas and market price forecasts more closely track the September 2009 forecasts through the year 2021. Therefore, the March 2010 price forecasts represent the Company's most current forward view; an outlook which suggests softer prices in the near-term gas and electric markets.

Q. WHAT IS THE COMPANY'S CURRENT VIEW OF PRICES AT THE PALO VERDE AND MID-COLUMBIA MARKET HUBS?

A. According to the Company's response to OCS 8.1, the Company's price projections for Palo Verde and Mid-Columbia market hubs are lower in the March 2010 forecast compared to the September 2009 forecast. Table 3 below provides a comparison between the March 2010 and September 2009 price forecasts for these two market hubs. In Table 3, I show the annual high load hour (HLH) price forecast at Palo Verde and the annual flat price forecast at Mid-Columbia.

Table 3

	Palo Verde Average Annual HLH Prices		Mid-Columbia Average Annual Flat Prices	
	Sep-09	Mar-10	Sep-09	Mar-10
2010	$54.60	$42.40	$46.91	$38.50
2011	$59.97	$47.75	$50.81	$40.43
2012	**$60.94**	**$52.00**	**$51.46**	**$44.33**
2013	**$62.48**	**$54.50**	**$51.89**	**$46.53**
2014	**$63.95**	**$57.25**	**$52.79**	**$48.97**
2015	$65.50	$60.25	$53.99	$51.43
2016	$67.87	$65.84	$58.99	$57.02
2017	$69.62	$71.74	$63.53	$63.11
2018	$69.85	$75.00	$63.73	$65.61
2019	$74.08	$74.91	$67.27	$66.15

Since the Company's reliance on short-term resources is particularly acute in the 2012-2014 bridging period, prices in those three years are highlighted in Table 2 for comparison purposes. Focusing on the Palo Verde market, the Company's March 2010 price forecast is approximately 15% lower for 2012, 13% lower for 2013 and 11% lower for 2014. The same general forecast pattern holds for the Mid-Columbia market. Thus, the Company's March 2010 near-term market price forecasts appear to better substantiate the Company's deferral of gas and wind resources in its revised 2008 IRP action plan than its prior market price forecasts. However, there remains the issue of validating the reasonableness of the Company's March 2010 electric market price forecasts.

Q. DID YOU ATTEMPT TO ACCESS OTHER FORECASTS RECENTLY PUBLISHED TO CONFIRM THE REASONABLENESS OF THE COMPANY'S MARCH 2010 ELECTRIC PRICE FORECASTS?

A. Yes. In February 2010, the Northwest Power Planning Council (NWPPC) published its 6th Power Plan (Plan). Appendix D of the Plan includes the NWPPC's current forecasts for the Mid-Columbia market hub. Table 4 below compares PacifiCorp's March 2010 with the NWPPC's February 2010 forecast for the Mid-Columbia market hub.[13]

Table 4
Mid-Columbia
Average Annual Flat Prices

	PC - Mar-10	NWPPC Feb-10
2010	$38.50	$32.64
2011	$40.43	$37.43
2012	**$44.33**	**$44.54**
2013	**$46.53**	**$50.94**
2014	**$48.97**	**$57.77**
2015	$51.43	$63.12
2016	$57.02	$67.95
2017	$63.11	$72.08
2018	$65.61	$74.92
2019	$66.15	$78.23

Q. WHAT DOES THIS PRICE COMPARISON ON TABLE 4 INDICATE?

A. Starting in 2014 the NWPPC's price outlook for the Mid-Columbia market hub is significantly higher. For instance, in 2014 the NWPPC forecasts a price that is approximately 15% higher than PacifiCorp's price projection.

[13] In forecasting market electricity prices PacifiCorp and the NWPPC use different forecasting tools - PacifiCorp relies on the Midas model and the NWPPC uses the Aurora model. Additionally, the Company forecasted numbers are in nominal terms and the NWPPC numbers are reported in (2006) constant dollar terms. To facilitate an accurate comparison of forecasted market prices the Office requested that NWPPC provide its nominal price forecasts by market zone. This information was provided via e-mail on June 15, 2010 and the "PNW Eastside – All Hours" price forecast is used in Table 4 for comparison purposes. The Office can provide NWPPC's market zone price forecasts to interested parties upon request.

Thus, PacifiCorp's market price forecast for Mid-Columbia appears to be optimistic compared to the NWPPC's price outlook.

Q. WHAT IS THE OFFICE'S REACTION TO THE FACT THE TWO PRICE FORECASTS FOR MID-COLUMBIA SHARPLY DIFFER BEGINNING IN 2014?

A. Given that Mid-Columbia is a primary market hub in the Pacific Northwest, the Office expected to find better agreement between the two price outlooks. There is a concern that PacifiCorp market view is more optimistic at a point in time (2014) when the Company's system resource deficit position grows to 2,198 MW. The Office plans to request PacifiCorp's June 2010 forward price curves to see if any upward adjustments are made to the Company's market price outlook.[14]

Q. WHAT ADDITIONAL INFORMATION DID THE COMPANY PRESENT IN THE 2008 IRP UPDATE TO SUPPORT ITS MARKET RELIANCE STRATEGY?

A. On pages 41-42 of the 2008 IRP Update, the Company discusses changes to annual Front Office Transaction (FOT) acquisition limits. The two most significant changes presented in Table 4.2 of the IRP Update are:

- Elimination of the Nevada-Utah Border (NUB) market hub, which was prompted by the acquisition of firm Nevada Power transmission service from Mead to Utah beginning in 2012. This transmission service allows PacifiCorp to acquire up to 300 MW of 3rd Quarter 6 x 16 FOT Product from Mead in the 2012-2014 period.[15]

[14] PacifiCorp's June 2010 forward price curves will be the most current forecasts available prior to the scheduled August 17, 2010 hearing.
[15] The 300 MW increase in transmission service from Mead to Utah is temporary; it subsequently declines to only 100 MW for the 2015-2016 period.

- Increasing the maximum availability of the 3rd Quarter 6 x 16 FOT Product at Mona from 200 MW to 300 MW beginning in 2013 and continuing thereafter. This is an incremental increase of 100 MW compared to the assumption for Mona in the 2008 IRP.

These two changes increase the FOT acquisition limits by 300 MW in 2012 and by 400 MW for the years 2013 and 2014. Therefore, the Company asserts it can move 400 MW of additional FOTs into its eastern control area by 2013 to serve loads.

Q. CAN YOU DETERMINE FROM THE IRP UPDATE WHETHER THIS 400 MW TOTAL INCREASE IN ACQUISITION LIMITS WILL BE USED TO SERVE GROWING RETAIL LOADS OR ARE THERE NEW WHOLESALE SALES CONTRACTS IN THE BRIDGING PERIOD?

A. According to "East Changes - Market Sales" presented on pg. 35 of the IRP Update, the Company recently entered into new wholesale sales contracts for 2012 and 2013. These wholesale transactions involve a 250 MW sales contract in 2012 and a 300 MW sales contract in 2013.[16] Consequently, it appears that a substantial portion of the increase in FOT purchases made available by the 400 MW increase in acquisition limits will be used to meet new wholesale sales obligations in the Company's eastern control area and will not be used to serve retail load.

Q. IN THE 2008 IRP UPDATE DID THE COMPANY SPECIFICALLY DEFINE AND DESCRIBE THE DIFFERENT TYPES OF STANDARD MARKET PRODUCTS THAT IT REFERS TO AS FOT?

A. No. Whereas the Company furnishes a more detailed description of FOT in its 2008 IRP (see pgs. 130-133), it simply states in the IRP Update that,

[16] Table 3.10 on page 34 of the IRP Update illustrates the differences by category between the 2010 Business Plan Portfolio that serves as the basis for the revised action plan for the 2008 IRP Update and the action plan associated with the 2008 IRP. On the eastside, two new wholesale sales of 250 and 300 MW are indicated in 2012 and 2013, respectively.

> "Front office transactions represent contracts for standard market products acquired on a forwards basis typically for a one-to-three year term." (IRP Update, pg. 27-28)

Q. WOULD IT BE USEFUL FOR THE COMMISSION AND OTHER PARTIES TO UNDERSTAND THE VARIOUS TYPES OF STANDARD MARKET PRODUCTS THAT ARE PRESENTLY AVAILABLE TO THE COMPANY AND HOW THEY MIGHT DIFFER BY MARKET HUB?

A. Yes. Since the Company's 2010 Business Plan Portfolio depends heavily on front office transactions to meet load requirements, a complete description of standard market products that are currently available, and possible variations on those products, by market hub would be useful.

Q. IN THE 2008 IRP UPDATE DID THE COMPANY IDENTIFY AND DESCRIBE FRONT OFFICE TRANSACTIONS THAT HAVE ALREADY BEEN ACQUIRED FOR THE BRIDGING PERIOD?

A. Yes. In Table 3.6 of the 2008 IRP Update (pg. 25), the Company identifies six FOTs for the 2010 -2013 period that are considered as <u>existing resources</u> in calculating the Company's system load and resource position.[17] These FOTs are categorically separated into (a) two firm market purchase contracts and (b) four exchange contracts. The firm purchases total 150 MW, the market hub is Mona and the contract terms range between 2010 - 2012. The exchanges total 300 MW, the market hubs are Mona and Four Corners and the contract terms range between 2012 - 2013. Copies of these contracts were provided to the Office as Confidential Attachment 8.5 in response to OCS DR 8.5.

[17] The Company's response to OCS DR 8.6 confirmed that these FOT transactions are treated as existing resources and do not serve to reduce the amount of incremental short-term resources indicated in Table ES-1 of the 2008 IRP Update.

Q. DO THESE SIX SPECIFIC FOT TRANSACTIONS PROVIDE SOME ASSURANCE TO THE COMMISSION THAT THE COMPANY WILL BE ABLE TO RELIABLY AND ECONOMICALLY CONTRACT FOR THE LEVELS OF FOT TRANSACTIONS INDICATED IN ITS 2008 IRP ACTION PLAN?

A. This will depend on the liquidity and depth in the western market to support PacifiCorp's FOT volumes that total 1,223 MWs by 2014. The Commission should require the Company to provide its current analysis of market liquidity and depth.

Q. IS THERE A REASONABLE STARTING POINT TO GAIN AN UNDERSTANDING OF CURRENT PROJECTIONS OF RESOURCE ADEQUACY IN WESTERN POWER MARKETS?

A. Yes. WECC regularly publishes a Power Supply Assessment (PSA) for the western power market. These PSAs include sub-regional load and resource balance forecasts under various assumptions and conditions.

Q. WHAT IS THE MOST RECENT VINTAGE OF WECC'S POWER SUPPLY ASSESSMENT (PSA) FOR THE WESTERN MARKET?

A. The latest PSA was published October 2009 and is based on data provided by WECC member utilities in Spring 2009. The October 2009 PSA includes a 2.0% increases in existing and Class 1 resources for 2010 and a 2.8% increase for these resources for 2017. Over the same time period, demand destruction due to the economic recession has reduced load forecasts by an average of 3.6%. According to WECC, certain sub-regions that were projected to be deficit in the 2008 PSA are now forecasted to be surplus in the 2009 PSA.[18]

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Q. HOW ARE THE ANALYSES AND RESULTS IN THE 2009 PSA ORGANIZED AND PRESENTED?

[18] 2009 PSA, Executive Summary, pg. 1.

A. WECC uses a supply adequacy model (SAM) to model 26 zones in the western interconnect, which are aggregated into seven subregions to perform load and resource analysis and report results. These seven zones include Canada, Northwest, Basin, Rockies, Desert Southwest, No. Cal, So. Cal/MX. PacifiCorp's service territories are primarily in the Northwest, Basin and Rockies sub-regions. Since PacifiCorp is a major seller and buyer of power in the western market, it is also important to understand projections of resource adequacy in other sub-regions as well, especially the Desert Southwest market.[19] Lastly, the SAM model allows economy transfers of power to occur primarily between sub-regions that are in close proximity. However, the model has limitations in that it is not an economic dispatch model. According to WECC this limitation is one factor contributing to an unrealistic level of surplus in the Northwest sub-region in the 2009 PSA.[20]

Q. BASED ON WECC'S CURRENT PROJECTIONS, WHEN DO RESOURCE DEFICITS FIRST APPEAR FOR THE BASIN, ROCKIES AND NORTHWEST SUB-REGIONS?

A. WECC presents these surplus-deficit projections according to two distinct scenarios -- a stand-alone scenario that assumes no economic power transfers among sub-regions and a more realistic scenario that assumes economic power transfers occur. Under the latter scenario, resource deficits initially appear for these sub-regions as follows: [21]

- Basin: Summer 2013;
- Rockies: Summer 2018;

[19] Market hubs such as Palo Verde, Mead, Mona and Four Corners provide important market resource opportunities for PacifiCorp, as noted by the Company in various sections of its 2008 IRP Update.
[20] To address this problem, WECC will be using PROMOD (an energy dispatch model) in future IRPs to more accurately reflect power transfers within the western interconnect.
[21] Initial year projected for resource deficit, by sub-region, is provided in the 2009 PSA in Table 3, pg. 9. Reserve margin assumptions differ across sub-regions and are provided in Table 4, pg. 9.

- Northwest: Surplus for entire period (2010-2018)

However, there are a few caveats that need to be briefly mentioned related to these resource deficit projections. First, the Basin, on a stand-alone basis, is severely resource deficit over the entire planning cycle. Thus, utilities operating in the Basin rely heavily on power purchases and exchanges to meet load requirements. Second, the Rockies is essentially in load and resource balance beginning in 2014 and continuing through 2018. If planned resources are not added or loads significantly increase, then the Rockies could quickly become resource deficit as well. Third, the surplus in the Northwest is overstated because of modeling limitations and hydro availability could deteriorate under pro-longed drought conditions.[22] Fourth, the reserve margins differ by sub-region and by season (summer-winter) within a sub-region. For example, the summer reserve margins for the Basin, Rockies and Northwest are 12.0%, 12.3%, and 18.6%, respectively. The summer and winter reserve margins for the Rockies are 12.3% and 13.5%, respectively. Consequently, increasing the reserve margin to a uniform level of 15.0% would more quickly deplete surpluses in the Basin and Rockies and push these sub-regions into a resource deficit position much earlier.

Q. YOU EARLIER STATED THAT RESOURCE ADEQUACY IN OTHER SUB-REGIONS, SUCH AS THE DESERT SOUTHWEST, IS IMPORTANT BECAUSE PACIFICORP IS AN ACTIVE TRADER IN THE WESTERN MARKET. WHEN DOES A RESOURCE DEFICIT FIRST APPEAR FOR THE DESERT SOUTHWEST MARKET?

A. The Desert Southwest is projected to become resource deficit in summer 2016. However, the possibility of the resource surplus ending sooner or later than 2016 largely depends on whether resources are added in

[22] WECC also notes that the surplus in the Northwest does not consider the limitations on the hydro system's ability to sustain capacity output levels beyond one hour and that this surplus is not available to support heavy load hour contracts in summer months.

California as presently scheduled.[23] Long delays or postponement of these resources will impact the length of the resource surplus for the Desert Southwest. Therefore, future resource developments in the Desert Southwest may substantially impact PacifiCorp because of its reliance on power from Desert Southwest market hubs to meet load requirements.

Q. DOES THE OFFICE HAVE CONCERNS REGARDING THE LEVEL OF EVIDENCE PROVIDED BY THE COMPANY TO SUPPORT ITS MARKET RELIANCE STRATEGY AND THE NEED FOR INDEPENDENT VERIFCATION OF THE LIQUIDITY AND DEPTH OF THE WESTERN MARKET?

A. Yes. While the Company identifies two different market products – purchases and exchanges – that it intends to rely on in the years 2010 – 2013, it provides the Commission and parties minimal analysis of the liquidity and depth of the western market in the critical 2012-2014 bridging period. The primary information shared with regulators and interested parties are its quarterly forward market price curves -- and the most recent one produced for Mid-Columbia is lower than NWPPC's Mid-Columbia price forecast over the same time period. Given the heavy reliance placed on short-term market products by the Company in the earlier years of the planning period, the Office believes that independent verification of PacifiCorp's market assessment is a required next step, especially given that the Company has asked for a Commission decision on its ECAM proposal later this year.

V. COMMISSION GUIDANCE AND CONCERNS REGARDING MARKET RELIANCE STRATEGIES

Q. HAS THE COMMISSION RECENTLY RAISED SIMILAR CONCERNS ABOUT THE NEXUS BETWEEN THE COMPANY'S APPLICATION TO

[23] 2009 PSA, pg. 49.

IMPLEMENT AN ECAM AND THE RISKS STEMMING FROM ITS RELIANCE ON SHORT-TERM MARKET RESOURCES?

A. Yes. On pages 29-30 of its 2008 IRP Order issued April 1, 2010, the Commission states:

> "We are concerned with the Company's stated confidence in managing the risk associated with reliance on the market for a significant portion of its customers' power requirements, especially combined with its comfort with planning to a 12 percent planning reserve. These decisions appear to leave little room for forecast error related to prices and loads. Meanwhile, the Company is asking for an energy cost adjustment mechanism in a separate docket. In part, the Company there argues it cannot effectively manage the risks, even one year out, of the costs associated with unexpected fuel prices, wholesale electric prices, and loads."

Thus, the Commission, like the Office and possibly other parties, is rightfully apprehensive about whether the Company has developed a credible strategy to manage market risk in order to protect Utah customers from large fluctuations in net power costs, given its ECAM proposal. Given these concerns, the Commission in its 2008 IRP Order provided guidance to the Company in four specific areas, including how the risk of relying on short-term market resources should be allocated between shareholders and ratepayers.

Q. PLEASE LIST AND SUMMARIZE THE FOUR AREAS WHERE THE COMMISSION PROVIDED GUIDANCE TO THE COMPANY.

A. On Page, 30 of its 2008 IRP Order, the Commission directs the Company to address the following areas in preparing its next IRP:

- Hedging: Include hedging costs in IRP analysis and perform sensitivity analysis to determine hedging strategies that minimize costs and risks for customers.
- Western Market: Include an analysis of the adequacy of the western market to support the volumes of purchases in the Company's action plan. The Commission also agreed with the Office that WECC is a reasonable source for this evaluation.
- Allocation of Risk: Identify whether customers or shareholders will be expected to bear the risk of reliance on the wholesale market.
- Additional Stochastic Analysis: Discuss methods to augment the Company's stochastic analysis of risks attendant to reliance on market purchases in an IRP public meeting.

Q. DOES THE PROCESS OF DEVELOPING SOUND PUBLIC POLICY ON ECAM ISSUES REQUIRE THE COMPANY TO FULLY ADDRESS THE FOUR AREAS DELINEATED ABOVE AS PART OF THE ECAM DOCKET?

A. I would think so. Given the close and immediate relationship between the Company's 2008 IRP and ECAM proposal noted by the Commission on pages 29-30 of its recent IRP Order, the sensible course of action is for the Company to perform the required analysis and provide evidence to the Commission so that it can make an informed decision on the appropriateness of the level, allocation and management of risk associated with the Company's market reliance strategy.

Q. HAS THE COMMISSION PREVIOUSLY RULED OR PROVIDED GUIDANCE ON WHO BEARS THE RISK OF PLANNING DECISIONS?

A. Yes. In its 2007 IRP Order, the Commission stated the following: "The Company bears the risk for any unreasonable cost to ratepayers associated with its decision to change the quantity and type of resources it procures based on asserted but unexamined risks." (2007 IRP Order, pg 34)

Q. WHY IS THIS GUIDANCE IMPORTANT?

A. Because FOT are a form of resource procurement. Fewer FOT are needed when more generation resources are constructed or procured and more FOT are needed when other procurement is postponed. If an ECAM is allowed, then the Company could pass through the costs of this procurement choice (FOT) directly to the customer. Under this circumstance, the risks of this procurement decision would not end up being borne by the Company as anticipated by the Commission in its previous IRP Order.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF INFORMATION PROVIDED BY THE COMPANY IN ITS IRP UPDATE, RESPONSES TO OFFICE DATA REQUESTS AND OUTSIDE SOURCES SUCH AS WECC'S 2009 PSA?

A. The Company has committed to new wholesale sales during a period when gas and wind resources are deferred, ~~reliance on~~ short-term ~~market~~ resources are heavily relied on to meet capacity ~~is sharply increased to meet load~~ requirements and the Basin sub-region is expected to be resource deficit. Concurrent with these developments is the Company's ECAM proposal, which is being debated before the Commission – a proposal that directly stems from the Company's claim that it has uncontrollable risks associated with fuel prices, wholesale electric prices and loads.

A significant portion of the risk the Company alleges as uncontrollable may actually be manageable by timely acquiring rather than continuing to defer planned physical resources and developing a credible risk management program. By minimizing planning risk, the Company can focus on a number of important risk management issues raised in the testimony of the Office's experts, including appropriately managing enterprise and operational risks. The question remains whether Utah ratepayers can be adequately protected against potentially higher rates resulting from PacifiCorp's market reliance strategy through the combination of a credible risk management program, possible volume limits on short-term resources, and proper design of an ECAM.

Q. HOW DO YOUR CONCLUSIONS RELATE TO THE POTENTIAL DESIGN OF AN ECAM?

A. The Office evaluated these issues in the context of potential ECAM design using the four steps outlined at the beginning of my testimony. First, we assessed the overall level of market reliance. Based on this assesment, the Office believes that not all short-term purchases or FOT transactions carry the same risk. Therefore, examining the level of market reliance alone is not sufficient. Second, we evaluated the evidence and independent verification of the Company's market assessment. This evaluation raised some serious concerns for the Office as there is little or no independent verification and it appears that the Company may be using an optimistic price forecast in critical years. Third, we reviewed the Commission guidance on these issues and whether the Company's plans are consistent with this guidance. Although some of the specific guidance I've cited was not directed to be completed until the next IRP, the Office has deep concerns about the extent to which this analysis has not been presented.

The Office believes it is only appropriate to consider market purchases in ECAM design after these previous three steps have been complete. The Office's fundamental conclusion remains the same as it was in Phase I: allowing the costs associated with market purchases in the ECAM would inappropriately shift risks of market price spikes to the customer, contrary to previous Commission orders that these risks would be borne by the Company. Therefore, the Office asserts that the Commission has two alternatives:

- Do not allow these costs into an ECAM until sufficient analysis justifies their inclusion, or
- Establish limits for the total amount of market purchases that could be allowed to flow through the ECAM.

Q. WHAT KIND OF LIMITS WOULD THE OFFICE RECOMMEND?

A. The Commission would have to take into account many factors in establishing limits for the inclusion of market purchases in an ECAM. First, all economy energy purchases should be allowed. It is always in the interest of customers for the Company to purchase energy when the costs are lower than the variable production costs. Before any limits are established, the Commission would need additional explanation of the types of short term products available and being utilized. Some types of FOT and short-term purchases are firm products that don't carry a lot of risk and for which restrictions may not be appropriate. Also, since it is presumed that energy not served (ENS) and differences between forecasted demand and actual will also be served from the market, an examination of these factors must also be included when considering potential limits in an ECAM design. Therefore, the Office's conclusion is that establishing limits would require a focused proceeding to determine what limits are reasonable and to avoid imposing arbitrary restrictions.

Q. WOULDN'T THIS TYPE OF ANALYSIS BE DIFFICULT TO ACCOMPLISH?

A. The Office acknowledges that this kind of analysis would be somewhat complex. However, it would provide the additional benefits of better understanding both of markets and the Company's planning process. Further, absent this kind of analysis, the inclusion of market purchases into an ECAM cannot be accomplished without an inappropriate shift of risk to consumers.

Q. PLEASE SUMMARIZE THE OFFICE'S RECOMMENDATIONS.

A. In deciding whether some form of ECAM is in the public interest, the Commission should do the following,

- Act upon the recommendations relating to the Company's hedging practices proposed by the Office's experts, Mr. Wielgus and Dr. Schell, that the Company should:

  (1) Perform a thorough analysis of all costs associated with its hedging practices (Wielgus);
  (2) Evaluate the use of options to reduce price volatility (Wielgus);
  (3) Evaluate the cost and benefit of the partial leveling of rates that results from hedging natural gas compared to acquiring more non-gas resources instead of gas resources. (Wielgus);
  (4) Compare the value of its hedging practices with other ways to address price volatility, such as the Enterprise Risk Management (ERM) approach (Wielgus);
  (5) Provide ample opportunity for affected parties to have input into the process of evaluating the Company's hedging practices (Wielgus);
  (6) Reduce its volume-based hedge targets to reflect historical system balancing levels (Schell);
  (7) Re-examine the acceptable range of TEVaR levels (Schell).

  Neither natural gas hedging costs nor natural gas fuel costs should be allowed in an ECAM design until this evaluation has been complete. If customers are going to be required to bear the risks of natural gas cost fluctuation, they should have input into the appropriate hedging strategies and associated costs.

- Require the Company to perform a comprehensive analysis justifying the adequacy and depth of the western market to support the projected volumes and prices associated with FOTs, as indicated in its current resource plan. This justification should include independent validation of the Company's market assessment. This analysis should be done before the costs associated with market purchases are allowed in any ECAM design and also required on an ongoing basis in all future IRPs.
- Consider developing and applying limits on the volume of FOTs for purposes of inclusion in an ECAM.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY ON MARKET RELIANCE ISSUES IN THE ECAM CASE?

A. Yes it does.