BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITYTO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN UTAH AND FOR APPROVALS OF ITS PROPOSED ELECTRIC SERVICE SCHEDULES AND ELECTRIC SERVICE REGULATIONS	))))))))	**DOCKET NO. 11-035-200**

REDACTED DIRECT TESTIMONY AND EXHIBITS OF

MARK T. WIDMER

ON BEHALF OF

UTAH INDUSTRIAL ENERGY CONSUMERS (UIEC)

June 11, 2012

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark T. Widmer and my business address is 27388 S.W. Ladd Hill Road, Sherwood, Oregon 97140.

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

A. I am a regulatory consultant and Principal of Northwest Energy Consulting, LLC ("NWEC"). I am appearing on behalf of the Utah Industrial Energy Consumers ("UIEC").

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. With NWEC, I provide regulatory consulting services related to electric utility operations, energy cost recovery issues, revenue requirements and avoided cost pricing for qualifying facilities. Since forming NWEC in 2008, I have testified on recovery of net power costs in general rate cases and power cost adjustment mechanism proceedings, avoided cost methodologies, resource prudence, and fuel recovery cases. Prior to forming NWEC, I was employed by PacifiCorp. While employed by PacifiCorp, I participated in and filed testimony on power cost issues in numerous dockets in Utah, Oregon, Wyoming, Idaho and California jurisdictions for 10 plus years. At the time of my departure from PacifiCorp, I was director of Net Power Costs. My full qualifications and appearances are provided as UIEC Exhibit___ (MTW-1).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses PacifiCorp's Generation and Regulation Initiatives Decision ("GRID") model and the forecast Net Power Costs ("NPC") GRID produced for the 12-month period ending May 31, 2013.

Q. PLEASE EXPLAIN NPC AND WHY IT IS IMPORTANT?

A. NPC is the sum of purchased power expenses, wheeling expenses and fuel expenses less wholesale sales revenues. Forecasting NPC is very important because it represents one of PacifiCorp's largest revenue requirement components and establishes the Energy Balancing Account (EBA) base NPC, which is Utah's recently approved mechanism for passing fuel and purchased power costs onto ratepayers.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend seven adjustments including one for Dr. Malko, which total approximately $58.6 million for PacifiCorp and approximately $25.2 million when allocated to Utah. These adjustments will produce reasonable system operation modeling of PacifiCorp's system, increase modeling accuracy, exclude non-recoverable costs, match costs and benefits, make corrections and insure that customers receive the benefits of ratepayer-funded assets. With the exception of the natural gas adjustment, the adjustments were calculated based on PacifiCorp's original filing, because the ultimate value of an adjustment will depend on which adjustments are adopted by the Commission. My adjustments do not foreclose the adjustments that may be proposed by others. For this reason, I recommend that the Commission require the Company to calculate the final adopted NPC based on the Commission adopted adjustments. My proposed adjustments are summarized below in Table 1.

Table 1
Summary of Recommended Adjustments

		Total Company	Est. Utah Jurisdiction
			SE 42.953%
			SG 43.155%
Adjustment Description			
1	Georgia-Pacific Camas	(307,671)	(132,465)
2	Hydro Forced Outage Rate Methodology	(545,866)	(235,017)
3	Cal ISO Fees	(5,952,780)	(2,562,910)
4	Major Market Caps	(12,087,235)	(5,204,038)
5	Short Term Transmission	(164,600)	(70,867)
6	Remove Reserve Shutdowns from EFOR	(1,085,807)	(467,483)
7	Natural Gas Swaps /1	(38,422,450)	(16,503,595)
	Total Proposed Adjustments	(58,566,409)	(25,176,375)

/1 Supported by Dr. Malko

Q. PLEASE SUMMARIZE THE SEVEN PROPOSED ADJUSTMENTS SHOWN ABOVE ON TABLE 1.

A. **Adjustment 1.** **<u>GEORGIA-PACIFIC CAMAS</u>**

The energy component of this purchase power contract was modeled with a different methodology than was used for other similar contracts, without providing justification for the change. This also overstates annual historical calendar year and 48-month average volume amounts. I instead modeled the contract energy using the same approach as is used in similar contracts for consistency and reasonableness.

Adjustment 2. **HYDRO FORCED OUTAGE MODELING**

Forced outages for hydroelectric projects were modeled based on an incorrect assumption that when a turbine is experiencing a forced outage, all water that would have been used for generation is bypassed downstream without producing any generation even if there are other operating turbines running at less than their maximum capability. My proposed adjustment uses a portion of the water PacifiCorp assumes is being bypassed for generation using otherwise under-utilized generation capability.

Adjustment 3. **CAL ISO TRANSACTIONS**

Cal ISO wholesale sales and purchase transactions were modeled to support inclusion of the associated wheeling expenses and service fees. However, while in actual operations the Cal ISO transactions were economic, those transactions were modeled uneconomically in PacifiCorp's proposed NPC. My adjustment removes these transactions and the associated wheeling expenses and service fees to prevent customers from paying for uneconomic transactions that do not provide a benefit and would not have been transacted if the results had actually been as modeled.

Adjustment 4. **MAJOR MARKET CAPS**

Artificial heavy load hour (HLH) and light load hour (LLH) market caps were modeled by PacifiCorp for all wholesale markets. However, these caps do not reflect how the system or markets operate and are inconsistent with how PacifiCorp developed the NPC forecast for its [redacted] and modeled the system in the Integrated Resource Plan (IRP). For these reasons, market caps should be eliminated for all wholesale markets except, the illiquid Mona market.

Adjustment 5. **SHORT-TERM TRANSMISSION**

PacifiCorp models all transmission expense in NPC no matter how small the expense for a particular contract. However, only transmission capability of one aMW or more is modeled in GRID. To correct this mismatch, I recommend that all transmission capability be modeled in GRID.

Adjustment 6. **RESERVE SHUTDOWNS**

PacifiCorp's calculated forced outage rate is not consistent with how GRID utilizes thermal plant forced outage rates. This disconnect between the rate used as an input into GRID and the GRID logic results in an overstatement of generation lost due to forced outages. PacifiCorp's forced outage rates used as a GRID input should be revised to eliminate the problem.

Adjustment 7. **NATURAL GAS SWAPS**

This quantifies the impact of Dr. Malko's proposed natural gas swaps adjustment.

Q. HAVE YOU PROPOSED THESE ADJUSTMENTS IN OTHER DOCKETS?

A. All of these adjustments with the exception of the natural gas swaps adjustment proposed by Mr. Malko have been proposed in other cases in this and other jurisdictions.

Q. WAS NPC MODELING IN THIS CASE REVISED TO ADDRESS SOME OF THE ADJUSTMENTS YOU PROPOSED IN PRIOR DOCKETS?

A. Yes. Despite having resisted some of these issues in the past, PacifiCorp's modeling in this case was revised by making adjustments to: (1) model flood control years in the Bear River hydro generation normalization, (2) match the hydro outage normalization period with the thermal generation outage period, and (3) remove Bridger Coal expense associated with fines and related expenses. Modeling changes were also made to capture Cal ISO transaction benefits, but only resulted in the inclusion of uneconomic wholesale transactions and associated wheeling expenses and service fees. Further, as discussed in my following testimony, there are still a number of problems that require adjustments to fix. It is especially important that these problems be addressed now that there is an EBA in Utah because ratepayers will be responsible for the actual costs.

Adjustment 1. **<u>GEORGIA-PACIFIC CAMAS</u>**

Q. PLEASE DESCRIBE PACIFICORP'S MODELING OF THIS POWER PURCHASE CONTRACT'S ENERGY.

A. The energy for this contract was modeled the same as the actual energy purchased during the 12-month period ended June 2011 instead of the way other contracts were modeled.

Q. DID PACIFICORP NORMALIZE THE VOLUME OF MOST OTHER CONTRACTS INCLUDED IN NPC USING A SINGLE YEAR OF DATA?

A. No. PacifiCorp's standard is to use a 48-month average to normalize energy for a large portion of the contracts included in GRID. For example, the following purchase power contracts are modeled based on a 48-month average: Deseret, Douglas PUD, DC Forest, Evergreen, Gem State, Hurricane, IPP Purchase, Simplot, Small Purchases East and West, and Sunnyside. Other GRID components such as wind generation, thermal and hydro forced outage rates, heat rates, and transmission capability are also modeled using a 48-month average. While it may be reasonable to deviate from the standard 48-month average normalization from time to time, it should only be done if there is justification to do so. Otherwise, normalization should be based on the 48-month standard.

Q. DID PACIFICORP PROVIDE JUSTIFICATION FOR USING A SINGLE YEAR TO MODEL THE ENERGY?

A. No.

Q. IS THE MODELED ENERGY COMPARABLE TO HISTORICAL ANNUAL VOLUMES?

A. No. Modeling the energy based on a single 12-month period of data overstates the annual volume when compared to calendar years 2008, 2009, 2010, 2011 and the 48-month average ended June 2011. Therefore, PacifiCorp's use of a single year of data for the period ended June 2011 produces an aberration and does not produce reasonable results.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Utah Commission adopt a 48-month average modeling approach because it is consistent with PacifiCorp's modeling for many other GRID inputs and produces results that are reasonable. This adjustment's impact is shown in Table 1.

Adjustment 2 **HYDRO FORCED OUTAGE MODELING**

Q. HAVE GRID HYDRO GENERATION INPUTS BEEN ADJUSTED TO REFLECT NORMALIZED FORCED OUTAGES?

A. Yes. PacifiCorp first calculates normalized generation using the VISTA model and then after the fact calculates the amount of generation lost due to forced outages in a spreadsheet model. Generation lost due to forced outages is only calculated for projects with an appreciable amount of storage. Projects with appreciable storage are located on three rivers: North Fork Lewis, Klamath, and North Umpqua Rivers. PacifiCorp uses an over-simplistic lost capacity method to calculate the amount of lost generation, which assumes that the amount of lost generation is equal to the total amount of energy that would have been generated by the capacity that is forced off-line. The length of the forced outages is based on the 48-month average ended June 2011 and the start time of the forced outages is mostly based on random selection.

Q. CAN YOU PROVIDE AN EXAMPLE OF PACIFICORP'S METHOD?

A. Yes. Assume there is a hydro facility with three 70 MW turbine generators, one of those three turbines has a 48-month average of a one day forced outage, the entire plant would have been operating at a 50% capacity factor if not on forced outage. Using PacifiCorp's lost capacity method, PacifiCorp would have calculated the amount of lost energy by multiplying 70 MW times 24 hours times 50%. This would produce lost generation of 840 MWh.

Q. DOES THIS METHODOLOGY TAKE INTO ACCOUNT ALL OF THE FACTORS THAT AFFECT THE AMOUNT OF GENERATION ACTUALLY LOST DURING FORCED OUTAGES?

A. No. During actual operations, there are several factors that impact the amount of generation lost due to forced outages. Those factors include available storage, storage requirements, the number of generation turbines at each hydro plant, expected inflows and downstream flow requirements. For example, if a facility has multiple turbines, ample storage, and is available to meet downstream flow requirements, the loss of one turbine does not necessarily mean that any generation is lost.

Q. IS A DIFFERENT METHODOLOGY BEING REVIEWED BY PACIFICORP THAT WOULD INCREASE THE ESTIMATED ACCURACY OF HYDRO GENERATION LOST DUE TO FORCED OUTAGES?

A. Yes. Commencing January 1, 2011, PacifiCorp began using a new method that is designed to more accurately track the amount of generation that is lost due to forced outages. The response to WIEC 18.2 from Wyoming Docket No. 20000-405-ER-11 described the new method as follows:

> At the time of occurrence of each outage, it is the amount of lost generation due to water bypassed during the outage. The amount is calculated by local operations management personnel who are the most knowledgeable about the particular circumstances of each forced outage event using the best available information and methods.[1]

The critical point here is that the new method uses the estimated amount of water that is bypassed and not used for generation rather than simply looking at the amount of capacity that is off-line. This new methodology may at some point in the future be adopted for ratemaking because it produces the most accurate estimate of generation lost due to forced outages.

Q. CAN THE COMMISSION USE THE RESULTS OF THE NEW METHOD IN THIS CASE?

A. No. Because hydro conditions and outages can vary substantially from year to year, GRID uses a 48-month average of outage data. Further, use of something less than a 48-month average would not provide consistent modeling between hydro and thermal forced

[1] *Wyoming Docket No. 20000-405-ER-11*.

outages because the new method only includes data for six months of the 48-month normalization period. Therefore, I am not recommending adoption of the new method in this case. Nonetheless, the new method provides valuable information that clearly demonstrates PacifiCorp's lost capacity method overstates generation lost due to forced outages.

Q. BASED ON THE FIRST SIX MONTHS OF DATA RECORDED USING THE NEW METHOD PLEASE EXPLAIN WHY THE OLD METHODOLOGY IS CLEARLY OVERSTATING GENERATION LOST DUE TO HYDRO FORCED OUTAGES?

A. The results for the comparable months between the lost capacity method and the new method are quite different. For example, PacifiCorp's lost capacity method assumed there are approximately 8.5 days of lost generation at Klamath projects[2] during the first six months of 2011. On the other hand, the new method shows that there were 0 days of lost generation for comparable facilities. This is most likely because the turbines that remained operational were able to make up for the lost generation from the turbine that went off-line so that the water was fully utilized in generating power. This difference demonstrates that the lost capacity method overstates the actual amount of generation lost due to forced outages.

[2] This excludes data for Eastside and Westside projects which are being taken out of service.

Q. DOES PACIFICORP'S LOST CAPACITY METHODOLOGY PRODUCE WORST CASE RESULTS FOR CUSTOMERS?

A. Yes. The lost capacity method assumes that all of the water that would have been used to generate electricity by the off-line turbine bypasses all of the other turbines at the project. But the reality is that if there are other operational turbines that are not running at full capacity, which is often the case, the under-utilized turbines can ramp up and use the water to generate electricity. That possibility is ignored by PacifiCorp. The end result of this extreme assumption is that generation lost due to forced outages is overstated.

Q. CAN THE LOST CAPACITY METHOD BE CORRECTED SO THAT IT PRODUCES REASONABLE RESULTS?

A. Yes. The methodology can and should be revised so that under-utilized turbines are better utilized in the calculation of generation lost due to forced outages. The incremental generation available from under-utilized turbines could be captured by subtracting normalized hydro generation of on-line units from the maximum generation of on-line units, to determine the amount of unused generation capability. Then the lost capacity method's assumed lost generation would be compared to the unused generation capability. If the unused generation capability is greater than the assumed lost generation calculated by PacifiCorp, there would be no lost generation. If the unused generation capability is less than the assumed lost generation calculated by PacifiCorp, lost generation would be equal to the assumed lost generation that exceeds the unused generation capability. In formula form the calculation would be made with the following formulas:

Maximum generation = Capacity of on-line units*weekly hours

Unused generation capability = maximum generation capability of units on-line – normalized generation

Lost generation = PacifiCorp assumed lost generation – unused generation capability

Furthermore, I believe my method is conservative because it does not assume additional generation could be captured through utilization of storage though this could possibly occur.

Q. PLEASE EXPLAIN HOW YOUR PROPOSED METHODOLOGY WORKS.

A. Using the same set of assumptions I used above when I explained PacifiCorp's lost capacity methodology, I will explain my proposed method. Again, assume there is a hydro facility with three 70 MW turbine generators, one of the turbines had a 48-month average of one forced outage day, and the plant was expected to operate at a 50% capacity factor at the time of the outage. As previously discussed, PacifiCorp's lost capacity method, produces 840 MWh of generation lost due to forced outages. The first step of my proposed methodology is to calculate the maximum generation capability of the two 70 MW units that remain on-line, which is 3,360 MWh. Then, calculate the unused generation capability by taking the maximum generation of 3,360 MWh minus the normalized generation (140 MW times 24 hours times 50%) or 1,680 MWh. 3,360

MWh minus 1,680 MWh equals 1,680 MWh of unused generation capability for the project's two remaining on-line units. In the last step, the 840 MWh of lost generation from the off-line turbine is compared to the unused generation capability of the remaining on-line turbines (1,680 MWh). Since this calculation produces a negative number, my methodology determines that no energy is lost despite the forced outage. So generation lost should be 0 instead of the 840 MWh PacifiCorp's methodology estimated. As previously explained and supported by PacifiCorp's new methodology, I believe that PacifiCorp can more fully utilize the two remaining on-line project generators by using the water that would otherwise have been used at the off-line generator so that there is no net loss of generation in the end.

Q. WHAT IS YOUR RECOMMENDATION?

A. The lost capacity methodology, which is used by PacifiCorp in this docket, overstates generation lost due to hydro forced outages. Until more data is collected using PacifiCorp's new methodology, the lost capacity method should be revised to capture the impact of underutilized on-line turbines, which can often take the place of the turbines that are off-line. For these reasons, I recommend that the Commission adopt my proposed revisions to PacifiCorp's lost capacity method of calculating lost generation due to forced outages. The adjustment amount is shown on Table 1.

Adjustment 3. **<u>CAL ISO WHOLESALE TRANSACTIONS</u>**

Q. DID PACIFICORP REVISE ITS CAL ISO MODELING IN RESPONSE TO YOUR PROPOSED ADJUSTMENT IN THE PRIOR GENERAL RATE CASE?

A. Yes. California ISO (Cal ISO) wholesale sales and purchase power transaction modeling was based on the actual monthly volumes for the 12-month period ended June 2011. This was done in an attempt to justify inclusion of $5.7 million of actual Cal ISO wheeling expenses and service fees in NPC, also based on actual information for the 12 month period ended June 2011.

Q. DOES THE EXPLICIT MODELING OF CAL ISO TRANSACTIONS ELIMINATE YOUR CONCERNS WITH THE INCLUSION OF CAL ISO WHEELING EXPENSES AND SERVICE FEES?

A. Not at all. The problem is that, as modeled in GRID, there are no annual benefits of the Cal ISO transactions in the test period even before taking into consideration the associated wheeling expenses and service fees. If that were the case, they would not have been entered so the modeling is obviously in error. To determine this, I first prepared a GRID study without the Cal ISO wholesale sales and purchase power transactions, but left the wheeling expense and service fees in NPC. <u>The study showed that some months NPC was higher and some months were lower as was the case for annual NPC</u>. Once the wheeling expense and service fees were removed, it showed that NPC was lower in all 12 months without Cal ISO wholesale transactions and associated costs. Therefore, the modeled Cal ISO wholesale transactions are <u>not economic</u> for customers. Based on the results of this analysis, it is easy to conclude that PacifiCorp would not have entered these transactions during actual operations if they had the same economics as modeled in GRID.

Q. NOTWITHSTANDING HOW THE TRANSACTIONS AND ASSOCIATED COSTS WERE MODELED, DOES PACIFICORP EXECUTE TRANSACTIONS WITH CAL ISO DURING ACTUAL OPERATIONS?

A. Yes. Wholesale transactions with the Cal ISO are executed during actual operations because there are times when those transactions represent the most economic transactions available to serve load and balance and optimize the system. This was explained in PacifiCorp's response to WIEC 6.11 in Wyoming Docket No. 20000-384-ER-10 which stated:

> The Company executes the most economical transactions available. Only if the "all in" cost of a transaction that will incur a new transmission wheel or fee is more economical than an available transaction that has no additional transmission cost (e.g. on existing rights) will that transaction be chosen. Wheeling expenses and fees are considered when choosing among available transactions.

However, while this may be the case during actual operations, this is not the case in PacifiCorp's proposed NPC because the transactions as modeled are uneconomic.

Q. IF THE ASSOCIATED CAL ISO WHEELING EXPENSE AND SERVICE FEES ARE EXCLUDED FROM NPC, WILL PACIFICORP STILL HAVE AN INCENTIVE TO EXECUTE THE MOST ECONOMIC TRANSACTIONS AVAILABLE DURING ACTUAL OPERATIONS?

A. Of course. PacifiCorp can include the costs and purported benefits of the Cal ISO transactions through the Energy Balancing Account (EBA). If these transactions actually lower NPC as claimed, the EBA will allow PacifiCorp to retain 30% of those benefits. Clearly, PacifiCorp has every incentive to execute these transactions, provided they in fact lower NPC as PacifiCorp claims.

Q. WHAT IS YOUR RECOMMENDATION?

A. As discussed above, PacifiCorp's modeling of Cal ISO wholesale transactions and associated wheeling expenses and service fees do not show an economic benefit to customers, as they purportedly provide during actual operations. The problem can be solved in one of two ways. The Cal ISO transactions and associated costs can be removed from GRID or a benefit can be imputed so that the transactions and associated costs produce a net benefit. Since PacifiCorp is unable to provide the net benefit generated during actual operations, these transactions should be removed from NPC. The adjustment amount is shown in Table 1.

Adjustment 4. <u>**MAJOR MARKET CAPS**</u>

Q. PLEASE EXPLAIN HOW PACIFCORP'S MARKET CAPS IMPACT NPC AND HOW THEY ARE MODELED?

A. Market caps artificially raise NPC charged to customers through an imposition of a maximum ceiling on the volume of wholesale sales that GRID can make in various wholesale sales markets. PacifCorp sets the caps equal to the 48-month average volume for a particular market less the volume of executed sales included as an input to GRID for heavy-load-hours (HLH) and light-load-hours (LLH). It should be noted however, that these caps are set at volumes below the actual transmission capability to various markets. That means that based on these caps, GRID will not make any additional wholesale sales to better utilize resources included in rate base, which have been paid for by customers, regardless of the transaction economics.

Q. DO YOU BELIEVE THAT MARKET CAPS SHOULD BE USED IN GRID?

A. No, with one exception. During actual operations, economic wholesale sales are made by PacifiCorp as often as possible when transmission is available. The one exception to this is the Mona market, where I also agree that using a market cap in GRID is appropriate because that market is illiquid. However, market caps should not be used in modeling the other more liquid markets and simply serve to artificially reduce the economic value of generation and transmission assets paid for by customers by preventing GRID from executing otherwise economic wholesale transactions.

Q. DOES MARKET CAP MODELING INCREASE NPC TO BE CHARGED TO RATEPAYERS BY PREVENTING GRID FROM ENTERING ECONOMIC WHOLESALE SALES?

A. Of course. I re-ran PacifiCorp's filed NPC study without market caps in all markets except Mona, and the results showed that the average cost of the economic resources that were prevented from being sold in the wholesale market was <u>$5.67/MWh</u> lower than the wholesale sales price. That means that resources that could generate a $5.67/MWh margin were prevented from being more optimally utilized in the GRID model because of the market caps. This is particularly surprising given the fact that PacifiCorp modeled Cal ISO transactions that were not economic. To date, PacifiCorp has not provided a credible analysis to demonstrate they cannot and do not actually make economic sales if transmission is available. In fact, as I explain below, that same assumption is not made in GRID in preparing PacifiCorp's [redacted] and in its Integrated Resource Planning process.

Q. HOW ARE MARKET CAPS CALCULATED?

A. The market caps are equal to the 48-month average volume of short-term firm (STF) wholesale sales for each market less the volume of executed STF wholesale sales for each market included in GRID. This method is very similar to the method I recommended in Idaho to apply to the Mona market only, but not to any other market.

Q. DID MR. DUVALL FILE ANY TESTIMONY IN THIS CASE SUPPORTING ITS MARKET CAP PROPOSAL?

A. No. Despite the fact that this issue was disputed in the last Utah rate case, which was settled, Mr. Duvall did not offer any testimony in support of their market cap methodology as part of their direct case. Since PacifiCorp must have known that this issue would come up again in this case, I suspect that they plan to present their case in rebuttal testimony. However, Mr. Duvall recently filed testimony in support of his proposed market cap methodology in the Oregon Docket No. UE-245, the 2013 TAM[3] proceeding. Based on that testimony, I can explain to the Commission why the Company's approach is not justified.

Q. HOW DOES MR. DUVALL EXPLAIN THE NEED FOR MARKET CAPS IN HIS 2013 TAM TESTIMONY?

A. Mr. Duvall offers a variety of arguments why market caps are appropriate including assertions that: (1) without caps, GRID assumes unlimited market depth; (2) without market caps, GRID has no constraints to reflect circumstances when counterparties may be unable to make economic transactions; (3) without market caps, the higher level of sales would lower the hourly market price and thereby lower wholesale revenues; and (4) without market caps, GRID assumes more market transactions than occur during actual operations. Each of these assertions is either wrong, unsupported, or both.

Q. AS TO MR. DUVALL'S FIRST ASSERTION, DOES THE GRID MODEL ASSUME UNLIMITED MARKET DEPTH IN THE ABSENCE OF MARKET CAPS?

A. No. Even without artificial market caps wholesale sales made by GRID are limited to the amount of transmission capacity available to wholesale markets.

[3] TAM is PacifiCorp's Oregon annual mechanism to reset NPC and set rates for customers. A copy of the relevant portions of that testimony is attached as UIEC Exhibit ___ (MTW-2).

Q. DOES MR. DUVALL HAVE ANY DATA TO SUBSTANTIATE HIS SECOND ASSERTION, THE CLAIM THAT MARKET CAPS ARE NECESSARY TO CAPTURE THE INABILITY OF PACIFICORP'S COUNTERPARTIES TO MAKE WHOLESALE TRANSACTIONS AT VARIOUS TIMES?

A. No. In UIEC Data Request 2.30 PacifiCorp was asked to identify economic heavy-load-hour and light-load-hour generation the Company had available for sale, but was unable to sell because of market depth, transmission constraints or market illiquidity. PacifiCorp's response stated: "The Company does not have custody, possession or control of the requested information because it has not performed the requested analysis." Therefore, there is no data available to substantiate Mr. Duvall's assertion.

Q. DOES GRID EXPLICITLY MODEL EXTERNAL LOAD REQUIREMENTS, TRANSMISSION CONSTRAINTS, MARKET ILLIQUIDITY, PLANT OUTAGES, HYDRO CONDITIONS AND OTHER FACTORS THAT MIGHT IMPACT A COUNTERPARTIES' ABILITY TO ENTER INTO AN ECONOMIC WHOLESALE TRANSACTION?

A. No. While GRID does model many of these PacifiCorp factors, it does not do so for the external power markets.

Q. DOES GRID IMPLICITLY MODEL FACTORS THAT IMPACT THE ABILITY OF COUNTERPARTIES TO ENTER INTO ECONOMIC WHOLESALE TRANSACTIONS?

A. Yes. PacifiCorp's Official Forward Price Curve (OFPC) is a critical input in the determination of NPC. The OFPC is developed using market price quotes from independent brokers, and those quotes are clearly heavily impacted by anticipated market conditions such as regional load requirements, transmission constraints, market illiquidity, plant outages, and hydro conditions. So, even without artificial market caps, the GRID market price inputs implicitly account for those factors. In fact, by adding market caps, PacifiCorp essentially rejects its own forward price curve by assuming that once you reach those caps there is no market for electricity at any price.

Q. IS MR. DUVALL'S THIRD ASSERTION THAT WITHOUT MARKET CAPS GRID OVERESTIMATES WHOLESALE REVENUE BECAUSE ADDITIONAL MARKET SALES WOULD RESULT IN A LOWER MARKET PRICE SUPPORTED BY EVIDENCE?

A. No. Mr. Duvall's assertion is once again unsupported by factual evidence. First, in order to know whether and how additional sales would impact the proposed market prices of electricity, Mr. Duvall would need to know (a) what assumptions were used by the independent third party brokers to develop the market price quotes provided to and used by PacifiCorp to develop the OFPC and (b) how those assumptions compare to the GRID test year assumptions. Since it is impossible for Mr. Duvall or any of us to know what assumptions the third party brokers are making, it is impossible to know what impact PacifiCorp sales volumes above the historic 48-month average would have on market prices, if any. Second, since the price quotes received from the third party broker's likely account for a range of possible market conditions, including conditions that might deviate from historic averages, it is then reasonable to assume that the OFPC already captures the price impacts of different possible supply and demand levels. In that case, imposing artificial market caps is cumulative and undercuts the OFPC already built into GRID.

Q. REGARDING MR. DUVALL'S FOURTH AND FINAL ASSERTION, DID HE PRESENT ANY TESTIMONY IN THE 2013 OREGON TAM PROCEEDING THAT THE GRID MODEL MAKES MORE SHORT TERM FIRM SALES WITH MARKET CAPS THAN ARE MADE DURING ACTUAL OPERATIONS?

A. Yes. Mr. Duvall's direct testimony presented a table, which he claimed demonstrates that GRID, with market caps, makes more STF sales than are made during actual operations. The contents of his table are shown below as my Table 2.

Table 2

GRID vs Actual (MWh)

	2007	2008	2009	2010	2011
GRID Sales Volume	18,344,663	31,618,999	13,229,220	10,490,633	9,212,496
Actual Sales Volume	8,934,640	7,892,769	8,089,341	4,754,401	6,802,152
Difference	(9,410,023)	(23,726,230)	(5,139,879)	(5,736,232)	(2,410,344)

Q. DOES THE DATA SHOWN IN TABLE 2 DEMONSTRATE THAT GRID MAKES MORE WHOLESALE SALES THAN OCCUR IN REALITY?

A. No. While Mr. Duvall's assertion appears to be correct at face value, a closer look demonstrates the information is not comparable because Table 2 compares apples and oranges. First, GRID short term firm sales volumes are normalized and also reflect normalized weather, hydro conditions, fuel prices and outages. Actual sales volumes are not normalized. Second, GRID sales volumes include "booked out" wholesale transactions, which are also not reflected in actual sales volumes. As such, it is impossible from the data presented by Mr. Duvall to draw any conclusion one way or the other.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN NORMALIZED DATA AND ACTUAL DATA?

A. Many of the inputs included in GRID have a high degree of variability and therefore, are normalized for the test period to reflect expected normal conditions. For example, GRID inputs include normalized weather, normalized loads, normalized hydro conditions, normalized wind generation, normalized transmission capability, normalized fuel prices and normalized levels of forced and planned outages. As is always the case, actual conditions deviate from normal conditions, sometimes by a little and sometimes by a lot. In conclusion, normalized data is not comparable to actual data because the normalized GRID inputs are completely different than actual results.

Q. PLEASE EXPLAIN BOOK OUTS.

A. Book outs for physical transactions are wholesale sales and purchase power transactions with equal hourly sales and purchase volumes scheduled at the same point of delivery that are netted together and settled financially. These transactions are not included in actual volumes because the energy is not delivered. For example, the GRID study for 2008 shows that the 31.6 million MWh in STF wholesale sales includes 25.4 million MWh in sales executed prior to when the GRID study was completed.[4] However, the actual volume of sales recorded shown on Table 2 for 2008 was only 7.8 million MWh. The primary reason for this difference is that 17.5[5] million MWh of executed sales included in the GRID volumes were booked out. Therefore, the large difference between GRID and actual volumes for 2008 shown on Table 2 is largely due to the difference in how the two numbers reflect energy transactions that are settled financially without an actual exchange of energy (i.e. booked out). Put another way, the two numbers used in Mr. Duvall's analysis are misleading and not comparable.

Q. GIVEN THE FACT THAT MR. DUVALL'S COMPARISON OF GRID VOLUMES TO ACTUAL VOLUMES IS A COMPARISON OF APPLES AND ORANGES, WHY DO YOU BELIEVE PACIFICORP'S NPC UNDERESTIMATES WHOLESALE SALES REVENUE?

A. Market caps create an artificial constraint that when modeled, reduce GRID's ability to optimize transmission and generation assets and wholesale sales revenues. PacifiCorp

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[4] The 2008 study volumes are so high because the executed sales were very high that year. The 2007 executed sales volume in the GRID study was 12.6 million MWh and the 2009 executed sales volume were 7.6 million MWh.
[5] 25.4 -7.9 = 17.5

continually looks for opportunities to buy and sell energy economically. The same is true for counterparties throughout WECC. Of course, transactions are always constrained by both counterparties' willingness to enter a transaction at a given price. But that constraint and other factors that influence market prices are already incorporated in NPC through the OFPC and other inputs. Given the inclusion of those factors in the OFPC, PacifiCorp has not presented a valid basis for the inclusion of additional constraints in the form of artificial market caps. Further, as I explain in my following testimony PacifiCorp does not use market caps [redacted].

Q. DOES PACIFICORP USE ARTIFICIAL MARKET CAPS FOR ITS [redacted] IN A MANNER CONSISTANT WITH HOW THEY ARE USED FOR RETAIL RATEMAKING?

A. [redacted] PacifiCorp also previously stated, in response to UIEC 6.46 in Utah Docket No. 10-035-124:

> ….the NPC studies used in the budget context are designed to forecast actual NPC as accurately as possible in the face of changing variables….

[redacted].

Q. WHAT MODEL WAS USED TO DEVELOP PACIFICORP'S [redacted] NPC?

A. The ______________ NPC is calculated with the GRID model that is used for retail ratemaking but without the artificial market caps, among other differences.

Q. DOES PACIFICORP USE MARKET CAPS IN ITS IRP ANALYSES?

A. No. The 2011 integrated resource plan (IRP) did not use market caps except to update a coal replacement study.[6] If artificial market caps are not necessary to evaluate the merits of future resource acquisitions, it does not make sense that they would be relevant in a rate case context. Further, it is very troubling that market caps are used to increase retail rates and then ignored when the Company wants to justify new generation or transmission resources. While troubling, PacifiCorp's modeling approach is not surprising because new resources are more economic when modeled without market caps for resource justification purposes and less economic when modeled with market caps in the retail rate setting processes.

Q. WHAT IS YOUR RECOMMENDATION FOR MARKET CAPS?

[6] See PacifiCorp's response to UIEC 4.3

A. Market caps should be rejected for all GRID modeled markets, except the illiquid Mona market, because PacifiCorp's reasoning for adopting market caps is flawed and unsupported, market caps would deprive customers of sales revenues they deserve from assets included in rate base, and because market caps are not used in the development of [redacted] Integrated Resource Plan. The adjustment impact is shown on Table 1.

Adjustment 5. <u>**SHORT TERM TRANSMISSION**</u>

Q. PLEASE EXPLAIN HOW THE COMPANY FORECASTS SHORT TERM TRANSMISSION EXPENSE AND CAPABILITY.

A. Transmission expense is set to equal actual expense for the 12 month period ended June 2011, adjusted for known and measurable changes. Transmission capability is set to the average transmission capability for the 48-month period ended June 2011 for average transmission capability for transmission links that exceeded 1 aMW. Transmission links less than or equal to 1aMW are not modeled.

Q. DOES THIS APPROACH CREATE A MISMATCH?

A. Yes. By including all expense no matter how small and excluding transmission capability for links equal to or below 1aMW a mismatch is created that disadvantages retail customers because they receive less benefit from transmission than is supported by the expense.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Commission should adopt the inclusion of all short-term transmission capability that is equal to or greater than 0.2 aMW. I chose this limit because it captures the bulk of the excluded transmission benefits. The adjustment impact is shown on Table 1.

Adjustment 6. **<u>RESERVE SHUTDOWNS</u>**

Q. PLEASE DEFINE RESERVE SHUTDOWN.

A. A reserve shutdown is a state in which a thermal unit was available for service, but not electrically connected to the grid for economic reasons.

Q. PLEASE EXPLAIN HOW RESERVE SHUTDOWNS IMPACT THE FORCED OUTAGE RATES INCLUDED IN GRID.

A. Reserve shutdowns are a deduction from the denominator of PacifiCorp's forced outage rate calculation. The formula is:

> Forced outage rate = total hours lost / [total possible hours less (planned outage hours and reserve shutdown hours.)]

Total hours lost is the sum of forced outages and derates, maintenance outages and derates and planned derates. Total possible hours equals total hours in the period multiplied by each generating unit's maximum dependable capacity.

Q. DO YOU AGREE WITH THE COMPANY'S MODELING OF FORCED OUTAGE RATES IN GRID?

A. No. While there is nothing wrong with PacifiCorp's calculation as a stand-alone statistic, its calculation of forced outage rates is not consistent with how GRID uses the forced outage rates. The outage rates used by PacifiCorp as a GRID input are calculated after reserve shutdowns, while GRID uses outage rates before reserve shutdowns. Therefore, PacifiCorp's method causes GRID to produce too much lost generation.

Q. HAVE YOU PREPARED AN EXAMPLE THAT ILLUSTRATES THE PROBLEM AND DEMONSTRATES YOUR PROPOSED SOLUTION TO CORRECT THE PROBLEM?

A. Yes. UIEC Exhibit____ (MTW-3) is an example of a 100 MW unit that has one 25-day forced outage, runs 16 hours a day, and is on reserve shutdown the remaining 8 hours a day. As shown in Line 1, that unit should produce 544,000 MWh a year (340 days not on forced outage*16 hours a day the unit is running and not on reserve shutdown*100 MW).

Using PacifiCorp's forced outage rate calculation, the plant would have a 9.9% forced outage rate by multiplying 25 days on forced outage times 24 hours in a day divided by the 6,040 hours in a year that the unit is not on reserve shutdown. Line 2 shows that when the unit is modeled in GRID with a 9.9% forced outage rate the unit only produces 525,987 MWh in a year – <u>18,013 fewer MWh than should be the case</u>. This is because rather than putting the unit on a forced outage for 25 days, GRID "simulates" the forced outage by derating the unit capacity by 9.9%. Thus, using the model's logic, the unit is considered a 90.1 MW unit (rather than a 100 MW unit) that is on reserve shutdown 8 hours a day for 365 days. As shown in Line 2, this results in the unit being on standby reserve for 2,920 hours (365 days * 8 hours a day) and runs the remaining 5,840 hours. As explained above, when the unit runs 5,840 hours times at a 90.1 MW capacity in GRID, the unit only produces 525,987 MWh a year. This is clearly a flaw in the GRID logic.

Line 11 of UIEC Exhibit___ (MTW-3) shows my proposed calculation to correct the overstatement of generation lost due to forced outages in GRID. I propose to eliminate the deduction for reserve shutdowns from the denominator of PacifiCorp's forced outage rate calculation that is used for the GRID input. Using this revised calculation, the forced outage rate is 6.85%. Line 11 shows GRID modeling with my revised 6.85% forced outage rate. For the year, under my approach, GRID runs the unit runs 5,840 hours and generates 544,000 MWh – the same results as occur in actual operations.

Q. HAVE YOU VALIDATED THIS ANALYSIS IN GRID?

A. Yes. I performed a GRID run with two hypothetical power plants, one using PacifiCorp's methodology and one using my proposed methodology. Using PacifiCorp's methodology, this unit generated only 526,009 MWh a year in GRID (equivalent to the 525,987 MWh calculated using the previously discussed spreadsheet analysis). Using my proposed methodology, the unit generated 543,996 MWh per year in GRID (equivalent to the 544,000 MWh calculated using the previously discussed spreadsheet analysis). Since we know that a unit with these operating characteristics would produce 544,000 MWh of energy a year, my proposed methodology is more consistent with actual operations.

Q. DOES YOUR PROPOSAL TO REMOVE RESERVE SHUTDOWNS FROM PACIFICORP'S OUTAGE RATE CALCULATION RESULT IN THE EXCLUSION OF RESERVE SHUTDOWNS FROM NPC?

A. No. The GRID model logic plus PacifiCorp's other screening adjustments put plants on reserve shutdown when they are not economic to run based on market prices during the test year.

Q. WHAT IS YOUR RECOMMENDATION?

A. The method proposed by PacifiCorp imports a logic flaw into GRID that results in too much lost generation. On the other hand, my recommended methodology corrects the problem and ensures generation is consistent with actual operations. For these reasons, I recommend that the Commission adopt my proposed methodology. The adjustment impact is shown on Table 1.

Adjustment 7. **<u>NATURAL GAS SWAPS</u>**

Q. MR. MALKO TESTIFIED THAT YOU CALCULATED THE IMPACT OF THE NATURAL GAS SWAPS ADJUSTMENT HE PROPOSES. PLEASE EXPLAIN HOW YOU CALCULATED THE IMPACT OF THE ADJUSTMENT?

A. The starting point for Mr. Malko's adjustment is the test year mark-to-market swaps losses based on the March 31, 2012 forward price curve[7]. Then the test period mark-to-market swaps losses as of June 30, 2011 are subtracted from the swaps losses based on March 31, 2012 to develop Mr. Malko's first possible total PacifiCorp adjustment. The same steps are also done for the test period swaps losses based on a July 29, 2011 mark-to-market[8] to develop Mr. Malko's second possible total PacifiCorp adjustment. The two possible total PacifiCorp swaps loss adjustments are then averaged and multiplied by 50% to develop Mr. Malko's proposed total PacifiCorp adjustment. Finally, Mr. Malko's total PacifiCorp proposed adjustment is allocated to Utah customers using the system energy allocation factor. The adjustment impact is shown in Table 1.

Q. DO YOU HAVE ANY GENERAL COMMENTS REGARDING MR. MALKO'S CONFIDENTIAL UIEC EXHIBIT ___ (JRM-1)?

A. Yes. I am surprised at PacifiCorp's continual incurrence of losses on its natural gas swaps month after month, the magnitude of the monthly losses and cumulative losses incurred since January 1, 2007, the expectation that the losses are expected to continue to

[7] Confidential Attachment UIEC 8.4-2
[8] This does not use an "official" Company forward price curve.

mount at least through the end of 2013 and that it appears they have not done much to control the losses.

Q. WHY ARE YOU SURPRISED THAT THE MAGNITUDE OF THE LOSSES HAS CONTINUED?

A. When confronted with continually mounting losses, I believe most people would take action to try to stem the losses, because they would come to the realization that what they were doing was not working. For example, if an individual had their 401k invested in three funds, two of which had a 10 plus percent annual average return over four years and the other fund accrued significant losses month after month over the same period, I believe the average person would have either reallocated a portion or all of their investment in the poorly performing fund to another fund, instead of sitting idly watching the losses continue to pile up in the poorly performing fund. There is an old adage in investing that says the trend is your friend. In PacifiCorp’s case, they bet against the trend of declining actual prices and didn’t do much to stem the losses.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.