BEFORE THE
PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Investigation of the Costs and Benefits of Pacificorp's Net Metering Program	))))	**Docket No. 14-035-114**

SURREBUTTAL TESTIMONY OF ELIAH GILFENBAUM

ON BEHALF OF

THE ENERGY FREEDOM COALITION OF AMERICA

August 8, 2017

Q. Please state your name for the record.

A. Eliah Gilfenbaum.

Q. Did you also cause to be filed on behalf of Energy Freedom Coalition of America ("EFCA") direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of this surrebuttal testimony is to respond to critiques of my analysis of Company overearnings, to respond to critiques of the long-run valuation of solar exports in my direct testimony, and to make several updates to that analysis. While there were multiple parties that responded to my valuation testimony in the rebuttal testimony round, my response in surrebuttal focuses primarily on the critique of Division of Public Utilities witness Artie Powell.

<u>RESPONSE TO ANALYSIS OF COMPANY OVEREARNINGS</u>

Q. What were witness Powell's arguments against your analysis of Company overearnings?

A. Witness Powell takes issue with my testimony that the Company is currently overearning (and that the size of the purported cost-shift associated with net metering is small in relation to the amount of annual overearning on an adjusted and unadjusted basis). His main argument is that comparing unadjusted overearnings to authorized revenues is apples to oranges, and that he does not believe a rate case could rectify the overearnings subsidy even if it did exist.

Q. What is your response to witness Powell's criticism of your discussion of the Company's overearnings?

A. The primary purpose of this section of my direct testimony was to demonstrate the scale of overearnings in comparison to the purported cost shift stemming from net metering. Even on an adjusted basis, my workpapers demonstrate that the Company is overearning by over $6M per year. Witness Powell seems to suggest that overearnings by the Company are not currently a problem, and even if overearning were occurring, a rate case would not necessarily address this issue. I disagree. While a utility might overearn in some years, and they might earn below their authorized values in other years, it is reasonable to expect that on balance, the average over several years should roughly equal the authorized returns. When overearnings are consistent, and of this magnitude, it is indicative of a need to adjust authorized revenues to ensure that ratepayers are not overcompensating the Company, and a rate case it is appropriate way to do that.

<u>UPDATES TO ANALYSIS FILED IN DIRECT TESTIMONY</u>

Q. Based upon your review of parties' rebuttal testimony, please describe the changes you would like to make to your analysis.

A: The updates occur in 2 areas, and are supported by updated workpapers:

1. Update to avoided CO2 cost to remove the portion of avoided cost that is already embedded in PacifiCorp's Official Forward Price Curve (OFPC) energy forecast.
2. Inclusion of integration and administrative costs to reflect total "net benefits."

First, regarding avoided CO2 costs, I partially agree with DPU witness Powell that some implied carbon price is embedded within the energy prices I cite. However, the implied price is lower than PacifiCorp's CO2 price forecast that it uses in the CO2 Price Sensitivity case. I update my analysis to account for the fact that part of that CO2 price is already accounted for, while the majority of avoided cost associated with PacifiCorp's "CO2 Price Sensitivity" case is not accounted for. This results in a reduction to the avoided CO2 cost of .17 cents per kWh.

Second, I agree that the analysis in my testimony only looked at the total benefits of exported generation, which I referred to as the "value of exports". A better way to characterize the "value of exports" would be to assess "net benefits", i.e. total benefits minus costs. Costs I deduct from the total benefits analysis include the integration cost associated with solar PV from the 2017 PacifiCorp IRP, and incremental administrative costs associated with solar customers. This results in a total cost of 1.16 cents per kWh.

1. Updated Avoided CO2 Cost

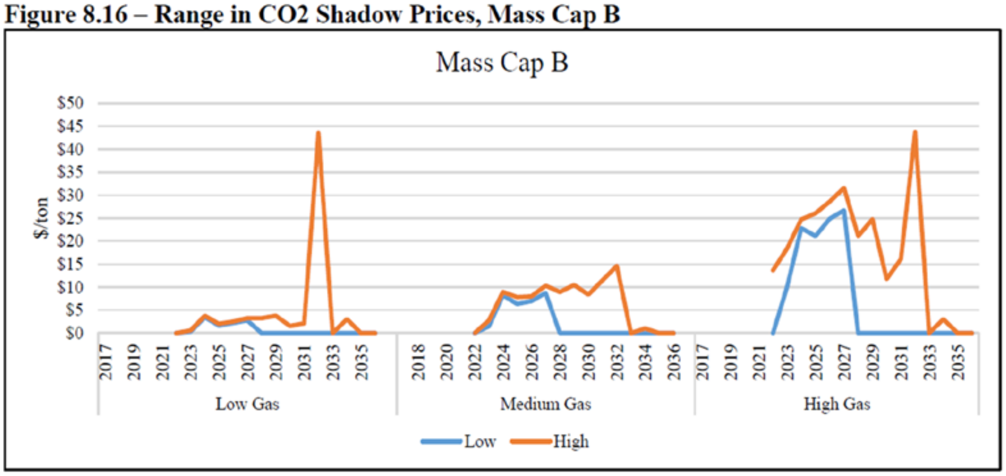
PacifiCorp uses a production cost model called Aurora to forecast electricity prices in its 2017 IRP. In the OFPC forecast, an explicit price on carbon is not included. However, upon closer examination, I found that the forecast is based on a configuration of Aurora "with gas prices consistent with CPP(a) and CPP(b)."[1] While an explicit price on carbon is not embedded, there is an implied cost of compliance associated with these forecasts. In an attempt to more conservatively reflect the impact of these projected CO2 compliance costs on wholesale electricity prices, I attempt to remove the shadow prices for CO2 implied by the CPP compliance that is embedded in the OFPC.

These shadow prices are described in the following way: "The CO2 shadow price represents the incremental system cost, expressed in dollars per ton, of meeting CPP mass cap

[1] PacifiCorp 2017 IRP; Vol.1 at p.167.

emission limit assumptions," but they "represent the opportunity cost of the CPP, but are not real expenses, and thus they are removed in the final PVRR reporting."[2] Because these shadow prices are outputs from each of the regional haze case portfolios, there is a range of shadow prices, and PacifiCorp chose only to depict the "low" and "high" extremes.

Figure 8.16 – Range in CO2 Shadow Prices, Mass Cap B



To be as conservative as possible, I use the high curve from this case, which represents the highest shadow prices for CO2 among all of the regional haze case portfolios examined by PacifiCorp. The expected shadow price associated with the price curve would in reality lie somewhere between the low and high extremes. I subtract the implied CO2 shadow price from the CO2 forecast to create a "net CO2 avoided cost" that represents PacifiCorp's forecast of the compliance value of reducing CO2 emissions beyond what is assumed in the base energy price forecast.

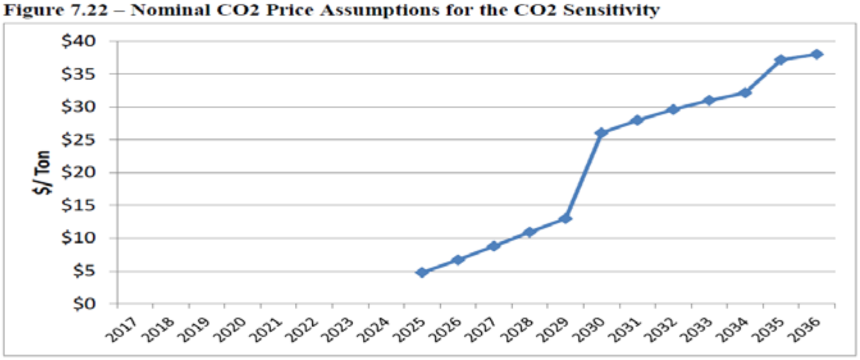
The CO2 compliance price forecast I reference is from PacifiCorp's "CO2 Sensitivity" case, which anticipates a higher CO2 price based on a more stringent compliance regime that

[2] *Id.* at pp.191, 211.

goes beyond what is required by the CPP. PacifiCorp describes the context for the CO2 Sensitivity case as follows:

> "With the introduction of EPA's CPP, PacifiCorp has reflected how future regulations targeting CO2 emission reductions in the electric sector might influence its resource plan. The CPP is reflected in all Regional Haze, core cases and sensitivities in the emissions-price scenarios. The CO2 Price sensitivity examines the impact of replacing the CPP with a CO2 price proxy beginning in the year 2025, based on the possibility that even if the CPP is not in effect, there will be some type of carbon-based policy in place by this time."[3]

Figure 7.22 – Nominal CO2 Price Assumptions for the CO2 Sensitivity



By subtracting out the implied shadow prices from this price forecast, I attempt to offer a more conservative and accurate view of the incremental avoided CO2 compliance costs attributable to solar exports.

2. Integration and Administrative Costs

Q: What value do you suggest for integration costs?

A: In its 2017 IRP, PacifiCorp conducted a Flexible Reserve Study wherein it calculated the integration costs attributable to wind and solar due to the higher operating reserves required to

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[3] *Id.* at p.176.

accommodate the intermittent nature of these resources. The study resulted in a $.60/MWh cost for solar,[4] which I adopt for my assessment.

Q. What value do you suggest for administrative costs?

A: The Company states these increased costs in Exhibit RMM-1:

- Engineering/Administration: $528,000
- Customer Service/Billing: $83,000

Based on NEM production of 52,877MWh in the test year, the per kWh administrative costs would be 1.16 cents based on these values. Some parties contested certain aspects of these cost calculations, and I generally agree with their concerns. In particular, I agree with Vivint witness Collins that RMP's estimate of engineering and administrative functions may be overstated to the extent portions are included that do not vary with the number of NEM customers. I also agree that the estimates for incremental billing costs may be overstated to the extent these costs are expected to change in the future when the Company's billing system is further automated.[5] While I expect that the Company's costs will be refined in the future to determine the appropriate export compensation for solar customers, I include the unmodified value here as illustrative.

Q. What is the impact of these adjustments on your original analysis?

A: Applying these changes results in a net value of exports of 11.18 cents per kWh.

[4] PacifiCorp 2017 IRP, Vol.2 Appendix F – Flexible Reserve Study; at p.133.
[5] Collins Direct Testimony at lines 383-402.

Net Benefits of Solar Exports ($/MWh)			
Benefits ($/MWh)	Energy	$	39.5
	Losses	$	3.8
	Updated- CO2 Compliance	$	1.2
	Generation Capacity	$	32.4
	Transmission Capacity	$	29.4
	Distribution Capacity	$	17.8
	Total Benefits	$	124.0
Costs ($/MWh)	Integration Costs	$	0.6
	Administrative Costs	$	11.6
	Total Net Benefits	$	111.8

SURREBUTAL TO CRITIQUES OF VALUE OF EXPORTS ANALYSIS

Q. What is witness Powell's critique of the valuation of solar exports you provide in your Direct Testimony?

A. Witness Powell's critique claims that my analysis is "one-sided" (i.e., only considers benefits and does not consider costs), and that I double counted future CO2 compliance costs. Both of these critiques are addressed above. In addition to these points, witness Powell takes issue with how I calculated avoided transmission and distribution costs and claims that my assessment of generation capacity value is inflated.

Q. How do you respond to witness Powell's claim that "common sense suggests that the value of NEM exports would be closer to an avoided energy rate plus, perhaps, a few incidentals"?

A. Mr. Powell's statement citing "common sense"—and referring to value categories beyond avoided energy as "perhaps, a few incidentals"—fails to approach the issue with the required analytical rigor and displays an overly narrow focus on energy-related avoided costs. While it seems likely that there will be an entire proceeding dedicated to evaluating these value categories, I think it is important to approach that assessment with an open mind based on the record of evidence. It is inappropriate to simplify this broader discussion to a small subset of value categories that "common sense suggests". My quantification of these categories represents an attempt to bring a more detailed and analytical viewpoint to the question of resource value.

Q. Witness Powell states that your valuation "does not pass reality checks" because it is higher than the average retail rate of 10.3 cents. How do you respond?

A: By citing the average residential rate as a reference point, witness Powell conflates average costs and benefits with marginal costs and benefits. It is clearly possible for marginal benefits to exceed average costs, and when that is the case, it is an indication that the system is under-investing in that particular resource (i.e. below the level that is economically optimal). For example, given the lumpy nature of large infrastructure investments, a relatively small decrease in load can have outsized marginal benefit to the extent a large growth-related infrastructure is deferred or avoided. While average costs may provide a benchmark for a qualitative assessment of fairness or equity, average costs do not put a cap on what the marginal benefit can be. Witness Powell incorrectly implies that the two are directly related and that one limits the other, which is not the case.

Q. Please describe witness Powell's critique of your regression analysis for transmission and distribution values.

A. Witness Powell shows that by adding an additional predictive variable to my regression, which he calls "Time-Trend", he achieves a higher R-squared value. He claims that this higher R-squared value indicates a better fit with the data, and in turn, creates a better predictive model of the dependent variable. His conclusion is that the marginal cost of transmission is actually negative $257/kW.

Q. How do you respond to this critique?

A: Through a misinterpretation of the regression coefficient in his multivariable regression, witness Powell implies that marginal transmission costs are negative (i.e. costs would decrease into the future as peak load increases). This result stems from a misinterpretation of the coefficients resulting from his regression. As I describe below, his interpretation that the -257 regression coefficient represents marginal transmission costs depends on the two predictor variables in his analysis (peak load growth and "Time-Trend") to be completely independent of one another. The truth is quite the opposite: the two variables are highly correlated, making his interpretation invalid.

Q. Please elaborate on why you believe witness Powell misinterprets the regression coefficient in his analysis.

A: Witness Powell implies that the regression coefficient represents the slope of the linear relationship between one of the predictor variables (cumulative peak load growth since 2001) and the dependent variable (cumulative growth-related transmission additions). This is a common misinterpretation of regression coefficients in multiple regressions of this type[6]. I have recreated his regression in Excel where "X Variable 1" is "time trend" and "X Variable 2" is peak load growth.

[6] https://www.ma.utexas.edu/users/mks/statmistakes/changeofwhat.html.

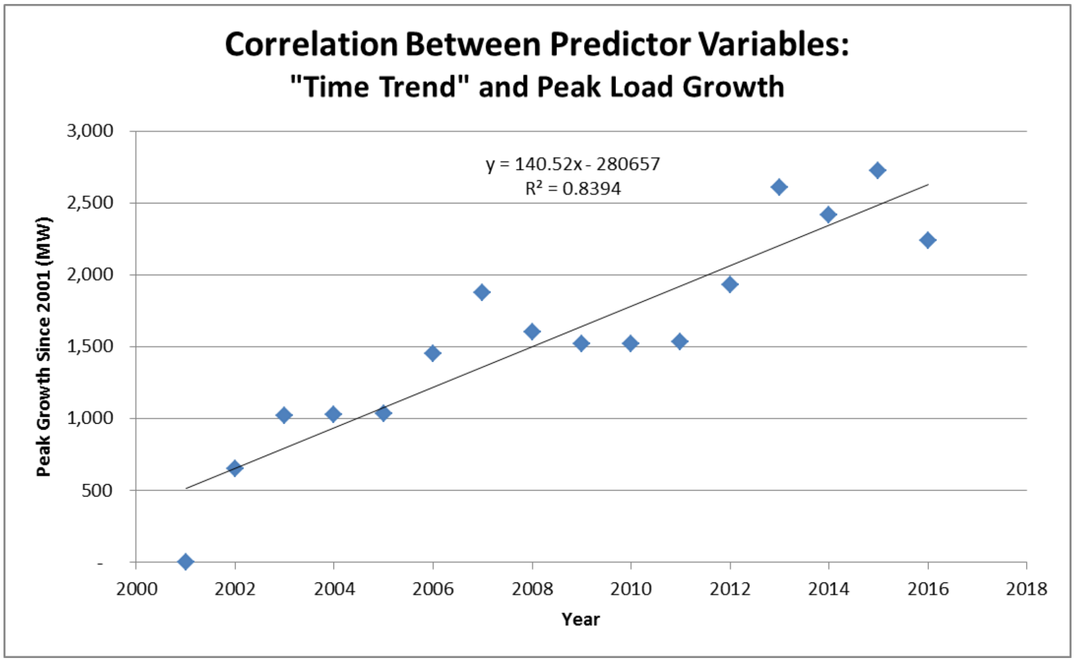
SUMMARY OUTPUT				
Regression Statistics				
Multiple R	0.983060955			
R Square	0.966408841			
Adjusted R Square	0.96124097			
Standard Error	173449065.2			
Observations	16			
ANOVA				
	df	*SS*	*MS*	*F*
Regression	2	1.12518E+19	5.63E+18	187.0033
Residual	13	3.911E+17	3.01E+16	
Total	15	1.16429E+19		
	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	-4.35094E+11	46925460881	-9.27202	4.29E-07
X Variable 1	217372051.7	23473158.98	9.260452	4.35E-07
X Variable 2	(257,218.70)	153047.9132	-1.68064	0.116687

The correct interpretation of the regression coefficient can be described in the following way:

> *"A regression coefficient in multiple regression is the slope of the linear relationship between the criterion variable and the part of a predictor variable that is independent of all other predictor variables."*[7]

The key phrase here is "independent of all other predictor variables." In the case of witness Powell's multivariable regression, both predictor variables (X Variables 1 and 2) are highly correlated since peak load growth has seen a general upward trend through time. Below is a graph of peak load growth vs "Time Trend":

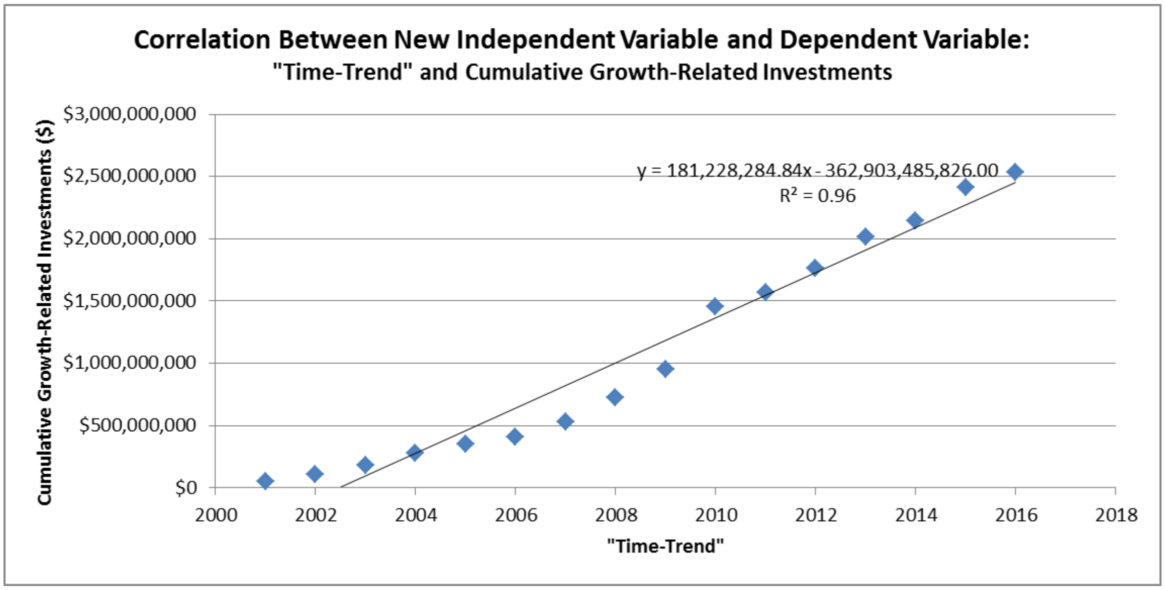
[7] http://onlinestatbook.com/2/regression/multiple_regression.html.

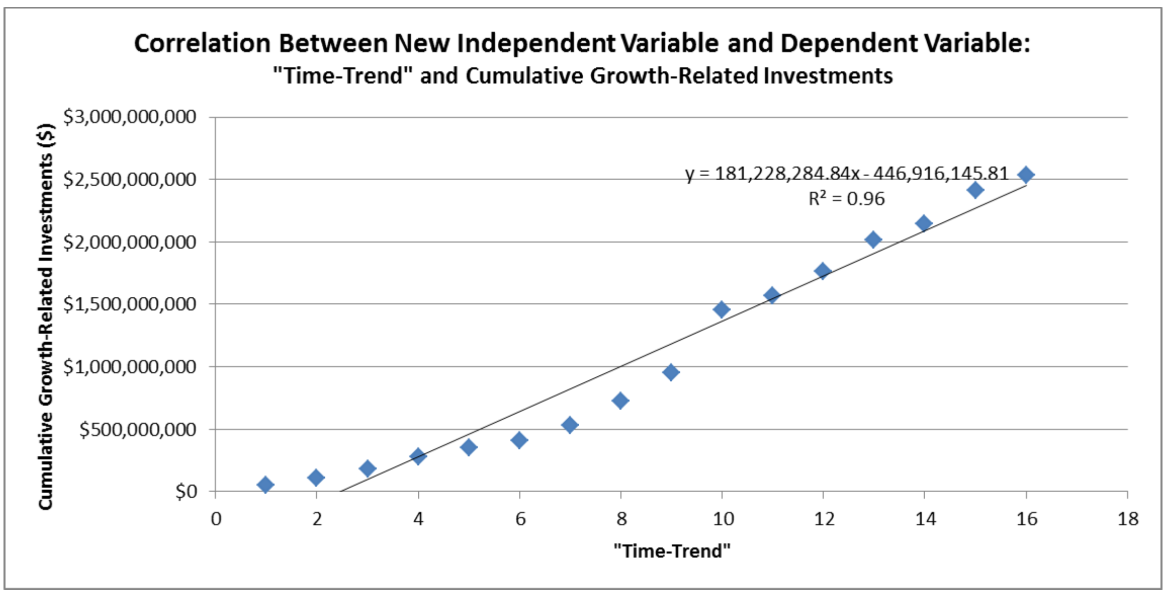


The R-squared value of .84 indicates a strong correlation between these two variables. For witness Powell's interpretation of the regression coefficient to hold true, these two predictor variables would need to have little to no correlation (i.e. be independent from one another). Because these variables are strongly correlated, the regression coefficient in Witness Powell's analysis does not represent what he claims it represents. This common misinterpretation explains the incorrect conclusion from witness Powell's analysis: that when regressing on both peak load and "time-trend", the marginal cost of transmission would be negative (i.e. transmission costs would tend to decrease as peak load increases).

Q. Do you have any additional critiques of witness Powell's approach?

A: Yes. In addition to misinterpreting the regression coefficients in his analysis, witness Powell overstates the significance of adding the "time trend" variable as a second predictor variable in his multivariable regression. "Time trend" has nothing to do with time per se: it is simply the sequence of years 2001-2016. Any set of sequential integers would produce the same result. To illustrate this, I replace his "time trend" variable with the numbers 1-16 and show that a simple linear regression of those integers vs. the dependent variable in my analysis (cumulative growth-related investments) produces an R-squared value of .96.





This strong correlation is not surprising because peak load tends to trend up through time, and cumulative growth-related investments are correlated with load growth. Any dependent variable that exhibits a linear upward trend would have a strong correlation with a set of sequential integers in the same way. Witness Powell's statement that adding this variable has a "significant" impact on the model's fit is a significant overstatement, and demonstrates the pitfall of assigning too much significance to an improvement in the R-squared value. Adding a new predictor variable that has a clear correlation with the dependent variable will improve the R-squared value in a multivariable regression, but does not necessarily indicate a higher quality regression.

Q. In footnote #12, witness Powell states that "Mr. Gilfenbaum appears to have constructed two variables, peak demand growth and cumulative transmission addition costs, that are positively correlated but have no causal relationship to one another." Do you agree that the two variables in your analysis have no causal relationship?

A: No. Witness Powell mischaracterizes one of the variables in my analysis, and this error renders his conclusion invalid. The dependent variable in my regression is not "cumulative transmission addition costs," as witness Powell alleges. Rather, the variable in my regression analysis is cumulative ***growth-related*** transmission addition costs, as described in my testimony[8], and in the NERA methodology that I follow, which has been accepted by the National Association of Regulatory Utility Commissioners.[9] By definition, this variable is caused by load growth. While well-informed experts can disagree about the degree to which specific transmission costs are growth-related vs. driven primarily by reliability or policy drivers, it is clear from my testimony and workpapers that I made an attempt to separate out growth-related costs from non-growth-related investments. Instead of providing evidence on the record as to why certain cost categories are not growth-related, witness Powell instead attempts to discredit my analysis through mischaracterization.

Witness Powell cites an article from the Harvard Business Review attempting to imply that the variables in my analysis may be correlated, but have not been shown to be causally

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[8] Gilfenbaum Direct; line 764
[9] pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD.

related. This article, however, boils down to universally recited, simple truism: "Correlation does not imply causation." Nothing in the article relates directly to my testimony or to methodological choices involved in estimating marginal transmission costs. While I agree with the general sentiments of that article, I disagree that it has any relevance to the discussion of my testimony. The "spurious correlation" charge witness Powell implies my analysis suffers from is in fact grounded in his misinterpretation of my analysis, and not a dubious causal link between the variables in the regression.

Q. Please describe witness Powell's critique of your assessment of generation capacity value.

A: Witness Powell claims my calculation of generation capacity value is "inflated" because I gross up the value to account for two effects. First, I account for the effect that behind-the-meter (BTM) solar has on capacity requirements, including the 13% planning reserve margin (PRM). Second, I account for the impact of temperature-driven derates of fossil capacity associated with summer peak conditions. Witness Powell provides no evidence or argument as to why the second adjustment is inappropriate, but defers to witness Faryniarz on the first adjustment. Witness Faryniarz elaborates on why he does not believe this adjustment is appropriate.

Both DPU witnesses fail to acknowledge that these adjustments are consistent with PacifiCorp planning assumptions, where BTM solar is treated as an adjustment to forecasted load, and therefore reduces capacity requirements associated with peak load and PRM. PacifiCorp describes the capacity balance analysis conducted as part of the IRP in the following way:

> "The capacity balance compares generating capability to expected peak load at time of system summer peak load hours. It is a key part of the load and resource balance because it helps guide the timing and severity of potential future resource need. It is developed by first reducing the hourly system load by hourly private generation projections to

determine the net system coincident peak load for each of the first ten years (2017-2026) of the planning horizon. Interruptible load programs, existing load reduction DSM programs, and new load reduction DSM programs from the preferred portfolio at the time of the net system coincident peak are further netted from the peak load forecast to compute the annual peak-hour obligation. Then the annual firm capacity availability of the existing resources, reflecting assumed coal unit retirements from the preferred portfolio, is determined. The annual resource deficit or surplus is then computed by multiplying the obligation n by the target planning reserve margin (PRM) and then subtracting the result from existing resources, accounting for available FOTs." [10]

Based on how Pacificorp evaluates capacity needs and based on its detailed study justifying the 13% PRM in the latest IRP, the adjustment in my analysis is warranted.

Q. Does PacifiCorp propose to raise the PRM target given that resources like BTM solar, DSM, and DR are able to contribute to their capacity adequacy targets?

A: No. Witness Farynairz's critique of the 13% PRM adjustment suggests that BTM solar does not contribute toward planning reserve requirements to the same extent as other types of capacity. If that were the case, then one would expect PacifiCorp's updated analysis to show that a higher PRM is justified to account for these "sub-par" capacity resources contributing toward the target. PacifiCorp does not come to this kind of conclusion, and instead maintains that the same 13% PRM is appropriate:

"PacifiCorp selects a PRM for use in its resource planning by studying the relationship between cost and reliability among ten different PRM levels, accounting for variability and uncertainty in load and generation resources….PacifiCorp will continue to use a 13 percent target PRM in its resource planning after evaluating the relationship between cost and reliability in the PRM study… the selected 13 percent PRM level ensures PacifiCorp can reliably meet customer loads while maintaining operating reserves, with a planning criteria that meets one day in 10 year planning targets, at the lowest reasonable cost."[11]

[10] 2017 PacifiCorp IRP; Vol.1 at p.86.
[11] PacifiCorp 2017 IRP, Vol.2 Appendix I – Planning Reserve Margin Study; at p.169.

Q: Are there examples of Utah-based analysis where the two adjustments you make are also applied to assess generation capacity value?

A: Yes. As I cite in my direct testimony, an independent 3rd party consultant named E3 was hired by the CAISO and Pacificorp to conduct an assessment of the benefits associated with PacifiCorp joining the CAISO's Energy Imbalance Market. One of the benefits assessed in this study was the value of decreased generation capacity requirements in PacifiCorp's territories. E3 applied the same 5% adjustment to account for temperature-driven derates of summer fossil fuel-fired capacity and the 13% adjustment to account for PacifiCorp's PRM. I adopt these values in my assessment, just as Pacificorp and E3 did for the EIM Benefits Study[12].

Q. Please describe witness Powell's assertion that you double count future CO2 compliance costs in your analysis.

A: Witness Powell states that "by including both energy and capacity values in his analysis, I believe Mr. Gilfenbaum double counts future CO2 compliance costs." He goes on to say that "When an incremental resource, such as distributed generation, displaces an IRP resource, the value of the risks (e.g., CO2 compliance costs) are already embedded in the value of the displaced resource. Adding an incremental amount for that risk would then double count the benefit of the incremental resource."

Q. Do you agree with witness Powell's rationale for why double counting of avoided CO2 costs exists?

A: No. While my updated analysis for avoided CO2 cost addresses the fact that there is an implied compliance cost embedded within the energy price forecast I use, I do not agree with

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[12] https://www.caiso.com/Documents/Study-TechnicalAppendix-Benefits-PacifiCorp-ISOIntegration.PDF

witness Powell's that the full value is double counted, nor do I agree with his rationale for why double counting exists. It's unclear why witness Powell believes that including both energy and capacity values inherently double counts CO2 compliance costs. Clearly the methodology for deriving a specific price forecast, and the assumptions used within a specific price forecast scenario, would influence how future CO2 compliance costs are accounted for in that forecast, and the extent to which the value is embedded. To illustrate this point, imagine two price forecasts that are derived through two different production simulations with different assumptions about future CO2 compliance costs. Price forecast A is based on a production simulation that assumes zero carbon price throughout the forecast horizon, while price forecast B assumes a carbon price forecast consistent with PacifiCorp's CO2 Sensitivity case from the 2017 IRP. Forecast A would not have any CO2 avoided cost embedded within the avoided energy values, while forecast B would.

In my analysis, I originally assumed that PacifiCorp's Official Forward Price Curve (OFPC) used in my calculations was like Forecast A, where no carbon price was explicitly embedded. Witness Powell, in his critique, assumed that the forecast I used was like Forecast B, which it was not. Upon closer inspection, I have found that the OFPC forecast, while it does not include an explicit carbon price, is based on a version of the Aurora production cost model that is "configured with CPP assumptions that align with scenarios developed for the 2017 IRP (CPP(a) and CPP(b))."[13] While it is still unclear to me exactly how these assumptions were implemented within Aurora to be consistent with the CPP, I take the assertion at face value, and I attempt to adjust my original analysis to include only the incremental avoided CO2 benefit associated with the CO2 Price Sensitivity case, as described above.

[13] PacifiCorp 2017 IRP; Vol.1 at p.151.

Q. With respect to administrative costs, DPU witness Powell suggests that it is appropriate to use the costs of the Solar Subscriber Program Rider associated with Utility Generation and Program Administration to adjust the solar export rate. Do you agree that 2.3 cents per kWh is an appropriate adjustment for costs associated with serving DG customers?

A: No. As described above, I use RMP's estimates of incremental administrative and billing costs associated with net metering as a proxy for the incremental costs associated with future solar customers. This value is roughly half the 2.3 cents recommended by witness Powell. The administrative cost figure cited by witness Powell includes costs of utility generation, administration, marketing, and billing for a program that is quite distinct from rooftop solar. I would not expect the Company to spend significant amounts of money marketing net metering or other programs that encourage customers to self-generate. An adjustment of 2.3 cents per kWh is excessive and does not represent a credible estimate of program administration costs for net metering or any future compensation tariff.

FUTURE COMPENSATION PROCEEDING

Q. Are you familiar with the joint proposal of the DPU and the Office of Consumer Services, which was attached as an exhibit to those parties' rebuttal testimonies?

A: Yes.

Q. Do you agree that there is merit in the OCS and DPU suggestion to have a Compensation Proceeding that will work out some specific aspects of the future valuation methodology for solar exports?

A: Yes. As the joint proposal contemplates, there is a need to compile substantial data to help populate the list of value categories. I agree that more granular data (e.g., load data at the circuit and substation level) will enable far more precise, location-specific modeling of the Company's system than is currently available and will help to identify precise impacts (positive or negative) that distributed solar is having on the grid. Additionally, it will be important for the Commission to consider the appropriate timeframe over which to conduct the valuation.

Q. Would it be appropriate for the Commission to establish an interim or transitional compensation rate for exports while the compensation methodology is developed in the separate Compensation Proceeding?

A: Yes. The original proposals put forward by DPU and OCS each signify a willingness to adopt an interim compensation rate prior to the development and application of a standard export compensation valuation methodology. There is sufficient evidence in the record, including my direct testimony, for the Commission to conclude that adopting an interim compensation rate that is close to the retail rate is just and reasonable. OCS, specifically, observes that current rates are not unjust and unreasonable, as any significant cost shift associated with net metering would take place at some time in the future. The Commission can approve an interim rate on the basis of this record and upon the principle of providing gradualism to allow prospective customer-generators the opportunity to adjust to the potential paradigm shift from net metering to an alternate compensation mechanism.

Q. Does this conclude your surrebuttal testimony?

A: Yes.