BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts	**DOCKET NO. 12-035-100**

Direct Testimony of Robert Millsap

For Renewable Energy Advisors

March 29, 2013

Q. Please state your name, title and business affiliation.

A. My name is Robert Millsap; I'm an analyst for Renewable Energy Advisors, a local renewable energy consulting company.

Q. **What is your association with this docket?**

A. I have been working with Energy of Utah, which has been involved in this docket since its inception. I've worked with other potential QF developers over the past two years.

Q. Why do you feel that you are qualified to testify in this docket?

A. I am not an avoided-cost expert, nor am I a GRID expert. I certainly respect the opinions of those who are. I believe that the subject of my testimony rests well below a level that requires significant expertise, and I hope that my concerns will be understood by all. My background is in financial analysis and I'm currently a financial analyst for a local university.

Q. What is the purpose of your testimony?

A. I am testifying to in order ask the Commission to consider a few issues that may adversely affect the outcome of current Schedule 38 PDDRR calculations:

- The exclusion of environmental costs from Schedule 38 calculations
- The application of GRID to PDDRR
- The extended deferral of PDDRR capacity payments
- PDDRR calculation results

Q. Please explain your concern about the exclusion of environmental costs from Schedule 38 calculations.

A. I must first note that by excluding environmental costs, I assume that Schedule 38 excludes potential carbon tax costs from its calculations. If I am incorrect in this assumption, I apologize in advance. The Company factors the possibility into its IRP projections by considering many scenarios, all of which include an assumption about a future Federal carbon tax. Applying an assumption to Schedule 38 that is in line with the Company's Base Case scenario seems appropriate. The most recent carbon tax base case of which I am aware is the assumption indicated in the Pacificorp 2011 IRP update: $16 / ton, increasing by 3% + inflation per year. [1]

Q. Please explain your observations about the application of GRID to avoided-cost calculations.

A. As I am not a GRID expert, I can only offer anecdotal evidence. The first example compares GRID avoided energy cost estimates between two Docket filings: Q-2 2012[2] and Q-4

[1] Pacificorp 2011 Integrated Resource Plan Update 3/30/2012

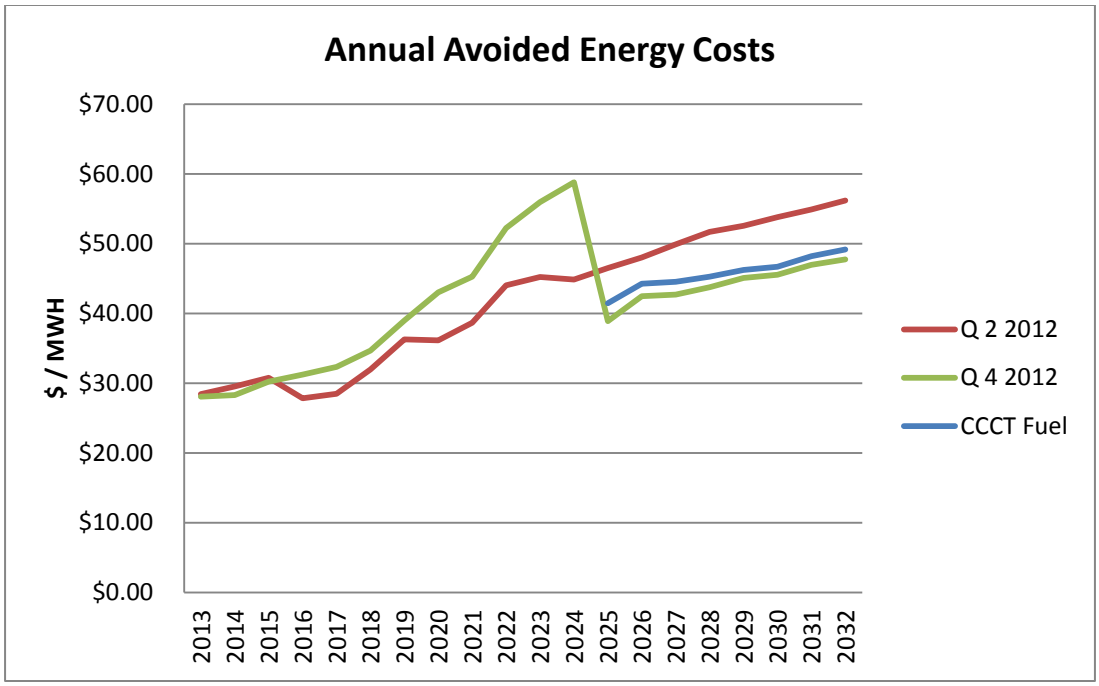
[2] Docket No. 03-035-14 Quarterly Compliance Filing – 2012.Q2 Avoided Cost Input Changes Exhibit B June 29, 2012

2012[3] Docket No. 03-035-14. GRID "Energy Only" data is drawn from Table 2 of the respective filings. "Fuel Cost" for the projected 2025 423 MW CCCT plant is drawn from Table 4 of the Q 4 filing. All costs are expressed as $/MWH. A comparison of estimates, along with the fuel cost estimates for the projected 2025 CCCT plant, is illustrated in the following table. All data is from the referenced Company filings:

Energy Only	Q 2 2012	Q 4 2012	CCCT Fuel
2013	$28.44	$28.10	
2014	$29.53	$28.34	
2015	$30.81	$30.22	
2016	$27.84	$31.23	
2017	$28.50	$32.35	
2018	$31.98	$34.69	
2019	$36.27	$38.98	
2020	$36.17	$43.02	
2021	$38.68	$45.27	
2022	$44.03	$52.23	
2023	$45.23	$55.96	
2024	$44.85	$58.83	
2025	$46.53	$38.91	$41.46
2026	$48.04	$42.48	$44.28
2027	$49.92	$42.72	$44.54
2028	$51.70	$43.77	$45.26
2029	$52.59	$45.09	$46.25
2030	$53.81	$45.54	$46.71
2031	$54.92	$46.95	$48.22
2032	$56.17	$47.75	$49.20

The same table is converted to the chart on the following page:

[3] Docket No. 03-035-14 Quarterly Compliance Filing – 2012.Q4 Avoided Cost Input Changes Exhibit B Dec 28, 2012



This chart raises a few questions, including the significant increase in Q-4 GRID estimates prior to 2025, and a GRID prediction that avoided costs after 2025 will be below the fuel costs of the CCCT plant. It is important to note that the fuel costs in the chart do not appear to include variable O&M costs.[4] In any case, I expect that such large changes between filings must cause difficulties for decision-makers.

Q. Please move on to your second example.

A A second example is illustrated by the Illustrative Wind Avoided Cost Table, submitted June 29, 2012, [5] on the following page. My attention was drawn to the July avoided-energy values in the table.

[4] Docket 12-999-01 Comments of Renewable Energy Advisors, Feb 11, 2013

[5] Docket No. 12-999-01, Re: 03-035-14, Quarterly Compliance Filing – 2012.Q2 Avoided Cost Input Changes, Exhibit D (Illustrative Wind Avoided Costs), Tables 2 and 3, http://psc.utah.gov/utilities/misc/miscindx/1299901indx.html

Appendix D

Table 2
Avoided Energy Costs - Scheduled Hours ($/MWh)
Utah Compliance 2012.Q2 - Wind 80 MW and 35% Capacity Factor
Partial Displacement of East Side 597 MW CCCT (Dry "F" 2x1)

Year		Winter Season					Summer Season				Winter Season			IRP Resource
	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Energy Cost
Energy Only														
2013	$25.56	$23.76	$24.30	$22.23	$19.21	$19.03	$19.85	$49.97	$38.29	$31.43	$26.46	$26.29	$24.45	$0.00
2014	$25.90	$25.29	$27.61	$27.70	$22.75	$23.04	$21.29	$59.55	$42.32	$35.78	$25.53	$19.39	$15.39	$0.00
2015	$26.29	$20.43	$24.24	$25.91	$25.11	$23.91	$25.46	$61.33	$47.36	$36.72	$25.96	$20.13	$20.16	$0.00
2016	$23.59	$21.01	$21.57	$26.59	$26.72	$25.95	$21.96	$6.31	$20.88	$22.08	$28.24	$22.54	$26.19	$29.82
2017	$23.49	$24.31	$23.59	$24.83	$25.73	$21.77	$22.57	$7.50	$22.06	$26.19	$25.66	$22.49	$23.16	$31.02
2018	$26.80	$26.51	$25.70	$26.22	$26.98	$22.82	$28.12	$9.00	$26.51	$31.48	$32.08	$26.44	$27.07	$34.47
2019	$30.14	$25.34	$26.76	$31.09	$31.14	$27.71	$33.70	$18.75	$30.33	$34.02	$33.19	$30.58	$32.86	$39.27
2020	$32.59	$37.00	$40.74	$32.07	$29.80	$32.68	$33.74	$21.17	$32.66	$35.05	$34.41	$22.34	$31.95	$40.47
2021	$31.14	$28.67	$28.99	$31.34	$30.14	$32.59	$32.01	$12.11	$31.06	$35.33	$35.58	$33.60	$30.25	$42.79
2022	$35.85	$36.28	$35.06	$37.19	$40.67	$36.11	$36.60	$4.54	$31.65	$39.43	$40.65	$35.27	$35.26	$47.02
2023	$36.89	$38.59	$38.84	$40.80	$43.07	$36.33	$33.60	$2.13	$32.43	$39.25	$40.52	$34.76	$35.46	$48.50
2024	$37.23	$39.51	$37.70	$39.34	$43.15	$31.48	$36.20	$0.83	$29.63	$40.45	$42.25	$38.25	$36.69	$47.66
2025	$38.82	$40.03	$39.09	$43.15	$44.83	$35.52	$35.55	$1.69	$30.29	$42.66	$43.16	$38.95	$38.65	$49.00
2026	$39.50	$40.31	$37.73	$40.77	$40.57	$39.23	$42.28	$7.34	$36.03	$45.93	$45.05	$38.46	$38.96	$51.82
2027	$40.25	$38.76	$38.65	$43.99	$41.46	$38.65	$42.18	$3.80	$35.48	$45.99	$45.72	$38.61	$42.45	$53.65
2028	$42.19	$51.11	$40.10	$42.31	$49.28	$39.12	$43.21	$1.61	$37.14	$48.90	$47.43	$39.23	$39.88	$54.78
2029	$42.82	$42.04	$40.51	$46.21	$50.54	$39.97	$45.68	$2.57	$37.62	$50.67	$49.04	$41.36	$41.39	$55.62
2030	$44.60	$46.54	$42.03	$45.96	$51.53	$41.81	$45.23	$5.73	$39.92	$51.90	$50.81	$43.75	$43.50	$55.91
2031	$45.52	$47.92	$43.84	$48.65	$51.79	$39.40	$43.28	$0.38	$34.38	$53.05	$54.52	$45.48	$45.20	$57.18
2032	$46.25	$50.44	$45.66	$47.76	$51.55	$40.02	$43.37	($6.28)	$34.67	$53.66	$55.52	$47.03	$46.38	$58.30

I filed a data request regarding the table, and the Company replied with the following:

"Response to REA Data Request 1.1

The partial displacement differential revenue requirement (PDDRR) method accurately values the qualifying facility (QF) generation profile relative to the proxy resource profile. The partial displacement mechanism is described on page 9 of the October 31, 2005 Order in Docket No. 03-035-14 (2005 Order) as follows:

> Two twenty-year GRID runs are performed to calculate hourly avoided energy cost. The first run is the existing utility system plus the planned resources contained in the Company's Preferred Portfolio in its most recent IRP; the second run is the same as the first run with two exceptions: the operating characteristics of the proposed qualifying facility are added with its energy dispatched at

zero cost and ***the capacity of the IRP resource is reduced by an amount equal to the QF capacity***.

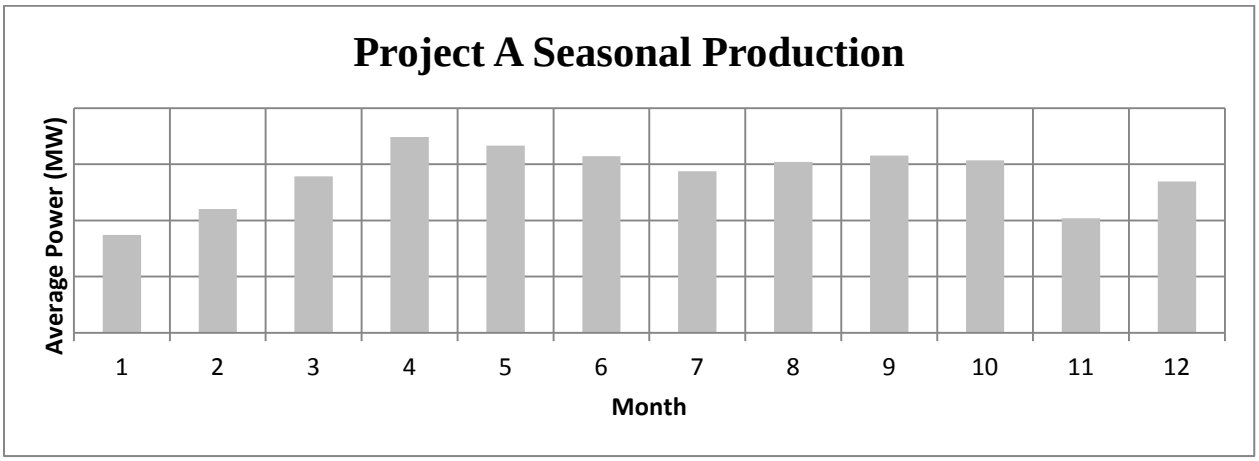
(emphasis added)

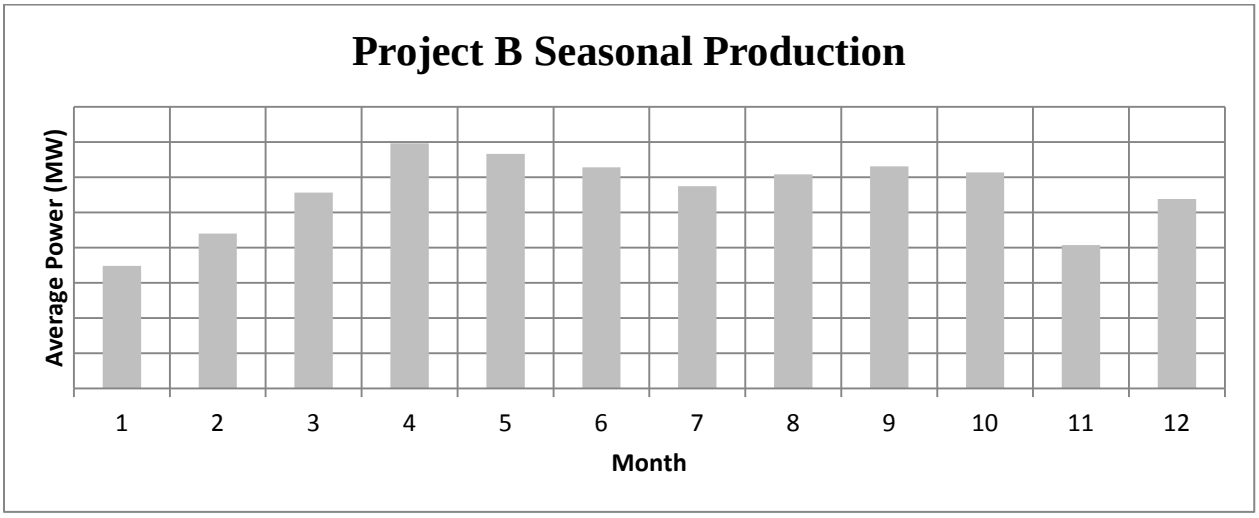
In the 2005 Order, the Utah Public Service Commission determined that the capacity contribution of a wind QF, and the corresponding displacement of the integrated resource plan (IRP) resource, would be equal to its capacity factor during heavy load hours (HLH). In the case of the 2012.Q2 compliance filing, the HLH capacity factor of the 80 megawatts (MW) hypothetical wind resource was 36.49 percent. Accordingly, in the second GRID run the capacity of the IRP resource (a 2016 combined-cycle combustion turbine (CCCT) at the time of the 2012.Q2 compliance filing) was reduced by 29.2 MW. In contrast, the hypothetical wind resource only produced 8.5 average MW (aMW) during the month of July, a 10.65 percent capacity factor and its lowest level of the year. Avoided energy costs are reduced to the extent a QF generates less energy than the proxy resource and the Company is required to replace the difference in generation with higher cost energy. To compute the avoided energy costs in Table 2 above, the displaced energy from the CCCT was greater than the energy production of the hypothetical wind QF in the month of July. The difference between the displaced energy and the energy from the QF must be replaced with market transactions at high summer prices. This differential contributes to lower overall avoided energy costs in July in Table 2.

The Direct Testimony of Company witness, Gregory N. Duvall addresses the appropriate method to determine the capacity contribution of wind resources to be used in the PDDRR method."

Q. What was your reaction to the response?

A. I've lived in Utah for forty eight years, but I don't remember weather like that. I've included the monthly profile for two Utah wind projects currently in the QF queue. The Company already has the data for these projects:





Q. Please explain your concerns about the extended deferral of capacity payments.

A. Clearly, PDDRR methodology is producing smaller and smaller Schedule 38 payments as the inclusion of increased purchased capacity in resource determination causes capacity payments to be deferred into the distant future. While it may or may not be to ratepayers' advantage to depend upon these purchases, the current PDDRR methodology drops most of the payment's capacity component. The resulting price is very low.

Q. Please comment on your final concern.

A. As mentioned earlier, PDDRR breaks total costs into an energy component and a capacity component, which are reassembled at the end of the process. The end result is a $/MWh value for each year of the payment table. The process relies on the use of capacity factors as the transformation takes place. The capacity costs are sourced on Table 4, and the PDDRR recombination takes place on Table 1. The following partial table is from the Q 2 2012 filing.[6]

Table 4
2011 IRP Resource Cost
CCCT (Dry "F" 2x1) - East Side Resource (4500')

Year	Estimated Capital Cost	Capital Cost at Real Levelized Rate	Fixed O&M	Variable O&M	Total O&M at Expected CF	Total Resource Fixed Costs	Fuel Cost	Total Resource Energy Cost	Total Resource Costs
	$/kW	$/kW-yr	$/kW-yr	$/MWh	$/kW-yr	$/kW-yr	$/MMBtu	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
CCCT (Dry "F" 2x1) - East Side Resource (4500')									
2010	$1,024	$83.97	$25.14	$3.82	$41.97	$125.94			
2011		$85.90	$25.72	$3.91	$42.95	$128.85			
2012		$87.19	$26.11	$3.97	$43.60	$130.79			
2013		$88.76	$26.58	$4.04	$44.38	$133.14			
2014		$90.45	$27.09	$4.12	$45.24	$135.69			
2015		$92.26	$27.63	$4.20	$46.14	$138.40			
2016		$94.01	$28.15	$4.28	$47.01	$141.02	$4.23	$29.82	$61.82
2017		$95.80	$28.68	$4.36	$47.89	$143.69	$4.40	$31.02	**$63.63**
2018		$97.62	$29.22	$4.44	$48.78	$146.40	$4.89	$34.47	$67.70
2019		$99.38	$29.75	$4.52	$49.67	$149.05	$5.57	$39.27	$73.10

The **$63.63** in column (i) is the expected cost to ratepayers of a CCCT plant in 2017, the first full year of operation. Please compare this number to the PDDRR-calculated **$47.79** avoided cost for the same year on Table 1 (following page). Changing the 85% capacity factor on Table 1 to 51.9%, the CCCT capacity factor, increases the calculated 2017 avoided cost to **$60.10**.

[6] Docket 12-999-01 Re 03-035-14 June 29, 2012 Exhibit B Tables 1, 4
http://psc.utah.gov/utilities/misc/miscindx/1299901indx.html

Appendix B

Table 1
Avoided Cost Prices
Utah Compliance 2012.Q2 - 100 MW and 85% Capacity Factor
Partial Displacement of East Side 597 MW CCCT (Dry "F" 2x1)

Year	Capacity Price $/kW-yr		Energy Only Price $/MWh [2]	Total Price @ 85.0% Capacity Factor $/MWh
2013	$0.00		$28.44	$28.44
2014	$0.00		$29.53	$29.53
2015	$0.00		$30.81	$30.81
2016	$82.26	(4)	$27.84	$38.86
2017	$143.69		$28.50	**$47.79**
2018	$146.40		$31.98	$51.64
2019	$149.05		$36.27	$56.29
2020	$151.60		$36.17	$56.47
2021	$154.31		$38.68	$59.40
2022	$157.06		$44.03	$65.12
2023	$159.91		$45.23	$66.71
2024	$162.80		$44.85	$66.65
2025	$165.72		$46.53	$68.78
2026	$168.71		$48.04	$70.69
2027	$171.93		$49.92	$73.01
2028	$175.20		$51.70	$75.17
2029	$178.52		$52.59	$76.56
2030	$181.90		$53.81	$78.24
2031	$185.55		$54.92	$79.84
2032	$189.08		$56.17	$81.50

Q. Do you have further comments?

A. I would like to thank the Commission for their consideration of this docket. I would also like to acknowledge the Company's timely and forthcoming responses to my data requests.

Q. Does that conclude your testimony?

A. Yes.

Submitted Respectfully,

Robert Millsap

For Renewable Energy Advisors