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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of: Rocky Mountain Power's Proposed Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities	**DOCKET NO. 14-035-T04**

Comments from Robert Millsap, for Renewable Energy Advisors

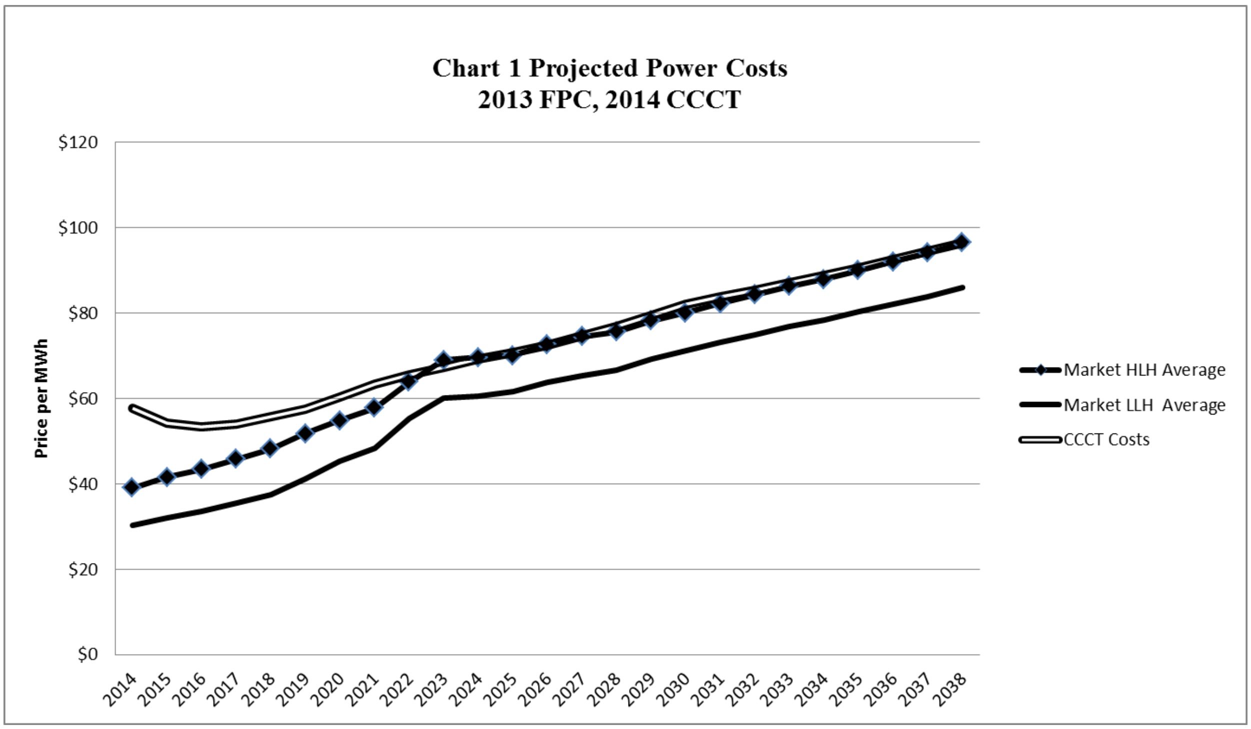
I'm writing to offer a few observations regarding Docket No. 14-035-T04.

The qualifying facility avoided cost subject is extremely complicated, and I must admit that it is clearly meant for better minds than my own. My understanding of the subject is limited, and I find myself drawn into a chain of assumptions and arguments that seem to have no beginning or end. They are certainly made in good faith, but they are so circuitous that I sometimes feel like I've been led into in a maze. Thankfully, the Public Service Commission actively encourages the open discussion of these matters.

I've been raised to believe that the proof is in the pudding, and I hope that looking at a few avoided cost results may add a little perspective for others who are struggling with this. These include charts that have been developed from projections obtained from Public Service Commission documents. The projections themselves do not necessarily represent my personal view, and I suppose the only guarantee that anyone can offer for projections that extend decades into the future is that they will not be exactly correct. The views expressed represent my own opinion, which is worth little. These observations concern Schedule 37 but also relate, to some extent, to Schedule 38.

The Recipe

To begin, let's look at the expected costs associated with some relevant power sources:



The thin lines trace market prices: the averages of Palo Verde and Mid-Columbia HLH and LLH annual prices that are taken from the March 2013 Forward Price Curve in last year's Schedule 37 filing.[1] I've used these values, rather than the values from Table 10 of the 2014 filing, because the current Table 10 excludes expected carbon tax costs. Since these particular costs are indeed expected to directly affect rates, they represent real costs that ratepayers are expected to bear. To my mind, the 2014 Table 10 has no relevance to actual expected ratepayer costs. The values on

[1] Docket Number: 13-035-T09 Exhibit A Table 10
http://www.psc.utah.gov/utilities/electric/elecindx/2013/13035T09indx.html

this table are far below market prices, and the cost of the next planned natural gas power plant (CCCT). I am not trying to disguise a decline in market prices subsequent to the 2013 filing. The average of the four 2014 prices in the March 2013 Forward Price Curve is $34.69. The average of the same four prices in the March 2014 Forward Price Curve is about 8% higher, at $37.51. The two tables are displayed side-by-side, with levelized values that I have added below each column.[2] The estimated effect of carbon legislation on future market prices is remarkable.

Schedule 37 Table 10 (2013 Filing Compared to 2014 Filing)

Table 10
Electricity Market Prices
$/MWH

Year	Market Price $/MWH			
	HLH		LLH	
	Mid-Columbia	Palo Verde	Mid-Columbia	Palo Verde
	(a)	(b)	(c)	(d)
2014	$37.24	$40.88	$29.94	$30.69
2015	$39.99	$43.13	$31.50	$32.59
2016	$41.99	$44.88	$32.50	$34.39
2017	$44.64	$46.88	$34.50	$36.39
2018	$47.14	$49.13	$36.50	$38.54
2019	$50.52	$53.03	$40.53	$41.84
2020	$53.26	$56.47	$45.17	$45.34
2021	$56.76	$58.83	$47.88	$48.74
2022	$61.08	$66.61	$56.38	$54.22
2023	$66.43	$71.57	$61.16	$58.88
2024	$66.79	$72.37	$61.87	$59.23
2025	$67.09	$73.11	$62.94	$60.27
2026	$69.63	$75.64	$65.29	$62.13
2027	$71.64	$77.45	$66.89	$63.88
2028	$72.72	$78.44	$67.93	$65.14
2029	$75.54	$80.95	$70.44	$67.95
2030	$77.13	$83.09	$72.40	$70.02
2031	$79.29	$85.21	$74.40	$72.01
2032	$81.21	$87.47	$76.22	$73.43
2033	$82.90	$89.59	$78.02	$75.56
2034	$84.36	$91.38	$79.85	$77.11
2035	$86.56	$93.40	$81.60	$78.97
2036	$88.92	$95.12	$83.49	$80.76
2037	$91.09	$97.08	$85.24	$82.50
2038	$93.49	$99.61	$87.38	$84.83
Official Forward Price Curve dated March 2013				
Levelized at 6.882%				
2014-2033	**$56.76**	**$60.85**	**$49.57**	**$49.15**

Table 10
Electricity Market Prices
$/MWH

Year	Market Price $/MWH			
	HLH		LLH	
	Mid-Columbia	Palo Verde	Mid-Columbia	Palo Verde
	(a)	(b)	(c)	(d)
2014	$41.38	$45.54	$28.96	$34.16
2015	$38.69	$40.75	$27.75	$30.13
2016	$38.06	$40.50	$28.31	$30.13
2017	$40.06	$42.50	$30.06	$31.88
2018	$42.56	$45.00	$32.06	$33.88
2019	$44.81	$47.00	$34.31	$35.88
2020	$47.05	$48.91	$37.59	$40.36
2021	$47.93	$49.46	$40.34	$45.07
2022	$49.43	$50.71	$41.87	$47.21
2023	$51.32	$52.34	$43.42	$48.89
2024	$53.32	$54.36	$45.26	$50.66
2025	$55.00	$55.74	$46.57	$51.79
2026	$56.78	$57.47	$48.19	$53.64
2027	$58.68	$59.93	$49.99	$55.76
2028	$61.11	$61.87	$52.10	$57.56
2029	$63.52	$64.54	$54.23	$60.01
2030	$65.96	$67.15	$56.53	$62.34
2031	$67.06	$68.48	$57.72	$63.49
2032	$68.32	$69.74	$59.06	$64.82
2033	$69.46	$71.31	$60.43	$66.17
2034	$70.59	$72.64	$61.63	$67.26
2035	$71.91	$74.33	$62.97	$68.71
2036	$73.37	$76.13	$64.47	$70.18
2037	$74.59	$77.51	$65.80	$71.43
2038	$75.99	$79.03	$67.76	$73.00
Official Forward Price Curve dated March 2014, adjusted to remove the impact of carbon regulation from prices for electricity.				
Levelized at 6.882%				
2014-2033	**$49.31**	**$51.18**	**$39.76**	**$43.75**

[2] IBID and Docket Number: 14-035-T04 Exhibit A Table 10
http://www.psc.state.ut.us/utilities/electric/elecindx/2014/14035T04indx.html

Why are market prices relevant? Schedule 37 is supposed to find the costs that are likely to be avoided by the introduction of a new resource. This process sets prices for Schedule 37 that should be ratepayer-neutral. A large proportion of our power is purchased through Front Office transactions, and the dependence on this source is expected to grow. The Schedule 37 filing outlines short-run avoided costs as follows: “During periods of resource sufficiency, the Company’s avoided energy costs are based on the displacement of purchased power and existing thermal resources as modeled by the Company’s GRID model. The results of the GRID analysis are provided in Confidential Appendix 4.”[3] I don’t know why this information should be confidential, but displaced resources for the Schedule 38 Qualifying Facility (QF) Queue are available in the most recent Schedule 38 filing.[4] They are not directly comparable, of course, but they give you a peek into what is going on. Sparing the reader a large set of tables, along with the ink and paper required for ten copies of these comments, avoided costs for Schedule 38 QFs include many avoided HLH market purchases. At this point in time, HLH market prices appear to be a large component of avoided costs. Since market prices are currently very low, below the production costs of some facilities, I think it makes sense to look at them closely.

There is also a more straight-forward way to look at this, but it falls outside of the avoided-cost framework. The power produced by a QF should be worth the market price for that power (minus transaction costs, and plus or minus transmission costs). Power companies buy and sell power every day, so the value is not hypothetical, it is realizable. In fact, we have excellent valuation information available for a hub very close to us, in Mona.

Well-within the avoided cost framework, power produced by a QF should be worth the power produced by a similar utility-owned facility.

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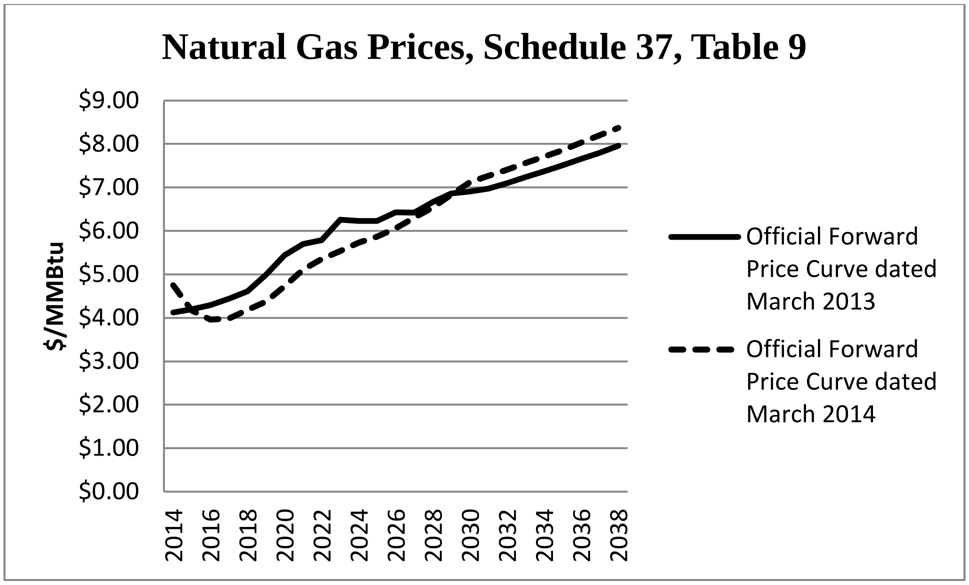
[3] Docket 14-035-T04 Exhibit B Avoided Cost Study Write-up Appendix 2 p.4

[4] Appendix A PacifiCorp Avoided Cost (GRID and Differential Revenue Requirement) Model Updates through February 2014 Docket No. 03-035-14

Returning to Chart #1, the red double line represents the expected cost of a combined cycle plant, planned for 2027. The future cost for the plant is projected from current costs, along with the expected price for fuel taken from Table 9. The fuel price tables from the 2013 and 2014 Schedule 37 filings are compared below:

Table 9	
Natural Gas Price - Delivered to Plant	
$/MMBtu	
Year	**Burnertip East Side Gas Fuel Cost**
	(a)
2014	$4.12
2015	$4.20
2016	$4.29
2017	$4.44
2018	$4.61
2019	$4.99
2020	$5.44
2021	$5.70
2022	$5.79
2023	$6.26
2024	$6.23
2025	$6.23
2026	$6.43
2027	$6.42
2028	$6.66
2029	$6.86
2030	$6.91
2031	$6.97
2032	$7.10
2033	$7.24
2034	$7.37
2035	$7.51
2036	$7.66
2037	$7.80
2038	$7.96
<u>Source</u>	
Official Forward Price Curve dated March 2013	

Table 9	
Natural Gas Price - Delivered to Plant	
$/MMBtu	
Year	**Burnertip East Side Gas Fuel Cost**
	(a)
2014	$4.75
2015	$4.17
2016	$3.96
2017	$3.98
2018	$4.18
2019	$4.37
2020	$4.73
2021	$5.11
2022	$5.35
2023	$5.54
2024	$5.73
2025	$5.87
2026	$6.06
2027	$6.30
2028	$6.54
2029	$6.83
2030	$7.12
2031	$7.27
2032	$7.41
2033	$7.56
2034	$7.71
2035	$7.86
2036	$8.03
2037	$8.20
2038	$8.37
<u>Source</u>	
Official Forward Price Curve dated March 2014	



2014 gas prices are actually higher than predicted in the March 2013 Price Curve, so I was quite surprised to see that they are now expected to dip, and not return to this year's level until 2020. It would be a welcome development if this remarkable turn of events lowers my home's natural gas bills over the next six years, but I won't hold my breath. Although the two estimates are very similar, lower near term prices and higher long run prices would have the effect of tilting the slopes of the March 2013 price curves. It would be helpful if more information was publically available.

In order to draw the cost curve on Chart 1 for the entire period, I've filled in missing values (italics) for Table 10[5], from 2014-2026, using the 2014 Gas forward Price curve on Table 9. I've added the levelized costs for the entire period and also for the "long term" period at the bottom of the table, as illustrated below:

[5] Docket Number: 14-035-T04 Exhibit A Table 10

Table 8 Total Cost of Displaceable Resources									
								Page 2 of 3	
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 "J", Adv 1x1 - East Side Resource (5,050')									
2012	$1,015	$80.04	$24.78	$2.64	$36.78	$116.82			
2013		$81.16	$25.13	$2.68	$37.31	$118.47			
2014		$82.38	$25.51	$2.72	$37.88	$120.26	*$4.75*	*$31.16*	*$57.61*
2015		$83.78	$25.94	$2.77	$38.53	$122.31	*$4.17*	*$27.36*	*$54.26*
2016		$85.29	$26.41	$2.82	$39.23	$124.52	*$3.96*	*$25.98*	*$53.37*
2017		$86.83	$26.89	$2.87	$39.94	$126.77	*$3.98*	*$26.11*	*$53.99*
2018		$88.39	$27.37	$2.92	$40.65	$129.04	*$4.18*	*$27.42*	*$55.80*
2019		$89.89	$27.84	$2.97	$41.34	$131.23	*$4.37*	*$28.67*	*$57.53*
2020		$91.51	$28.34	$3.02	$42.07	$133.58	*$4.73*	*$31.03*	*$60.41*
2021		$93.25	$28.88	$3.08	$42.88	$136.13	*$5.11*	*$33.52*	*$63.46*
2022		$94.93	$29.40	$3.14	$43.68	$138.61	*$5.35*	*$35.10*	*$65.59*
2023		$96.64	$29.93	$3.20	$44.48	$141.12	*$5.54*	*$36.34*	*$67.38*
2024		$98.38	$30.47	$3.26	$45.29	$143.67	*$5.73*	*$37.59*	*$69.19*
2025		$100.15	$31.02	$3.32	$46.11	$146.26	*$5.87*	*$38.51*	*$70.68*
2026		$102.05	$31.61	$3.38	$46.98	$149.03	*$6.06*	*$39.75*	*$72.53*
2027		$103.99	$32.21	$3.44	$47.85	$151.84	$6.30	$41.33	$74.73
2028		$105.97	$32.82	$3.51	$48.78	$154.75	$6.54	$42.90	$76.94
2029		$107.98	$33.44	$3.58	$49.72	$157.70	$6.83	$44.80	$79.49
2030		$110.03	$34.08	$3.65	$50.67	$160.70	$7.12	$46.71	$82.06
2031		$112.23	$34.76	$3.72	$51.67	$163.90	$7.27	$47.69	$83.74
2032		$114.47	$35.46	$3.79	$52.69	$167.16	$7.41	$48.61	$85.38
2033		$116.76	$36.17	$3.87	$53.76	$170.52	$7.56	$49.59	$87.10
2034		$119.10	$36.89	$3.95	$54.85	$173.95	$7.71	$50.58	$88.84
2035		$121.48	$37.63	$4.03	$55.95	$177.43	$7.86	$51.56	$90.59
2036		$124.03	$38.42	$4.11	$57.11	$181.14	$8.03	$52.68	$92.52
2037		$126.63	$39.23	$4.20	$58.33	$184.96	$8.20	$53.79	$94.47
2038		$129.29	$40.05	$4.29	$59.55	$188.84	$8.37	$54.91	$96.45
								Levelized at 6.882%	
								2014-2038	**$67.15**
								2027-2038	**$84.52**

Although the CCCT cost curve on Chart 1 tracks HLH prices in later years, it is higher over the near term, resulting in levelized costs that are much higher than expected levelized market costs.

The following costs are levelized at 6.882% for the 2014-2038 time frame.

March 2013 FPC Palo Verde/Mid-Columbia LLH average	$49.36
March 2013 FPC Palo Verde/Mid-Columbia HLH average	$58.81
2014 Schedule 37 CCCT costs	$67.15

I have not included the "adjusted" March 2014 price curve offered in the 2014 Schedule 37 filing because it does not include costs that are actually expected to be incurred by ratepayers.

GRID creates the bulk of the ingredients, and the workbook that accompanies the filing blends them into the avoided cost output tables and tariff pages. A number of changes have been made to the recipe this year, including:

- Table 7 is no longer linked to Table 5, but to the Tariff page, which gets its values from Table 6. This effectively disables the capacity factor adjustment that was available in earlier versions.
- The links between the short term section of Table 3 and Table 8 have been disabled.
- One of two payment options has been eliminated. Energy only payments eliminate the capacity factor adjustment that may have been available to potential developers in earlier versions.
- Levelized payments are no longer available. This makes no difference for ratepayers, but it does make developments much more difficult to finance.

- Wind and solar integration costs have been added. The levelized 2014-2036 wind integration cost is $5.06. My expectation was for a lower number.
- It would be interesting to know why wind integration costs are expected to rise at the following rates on Table 12:[6]

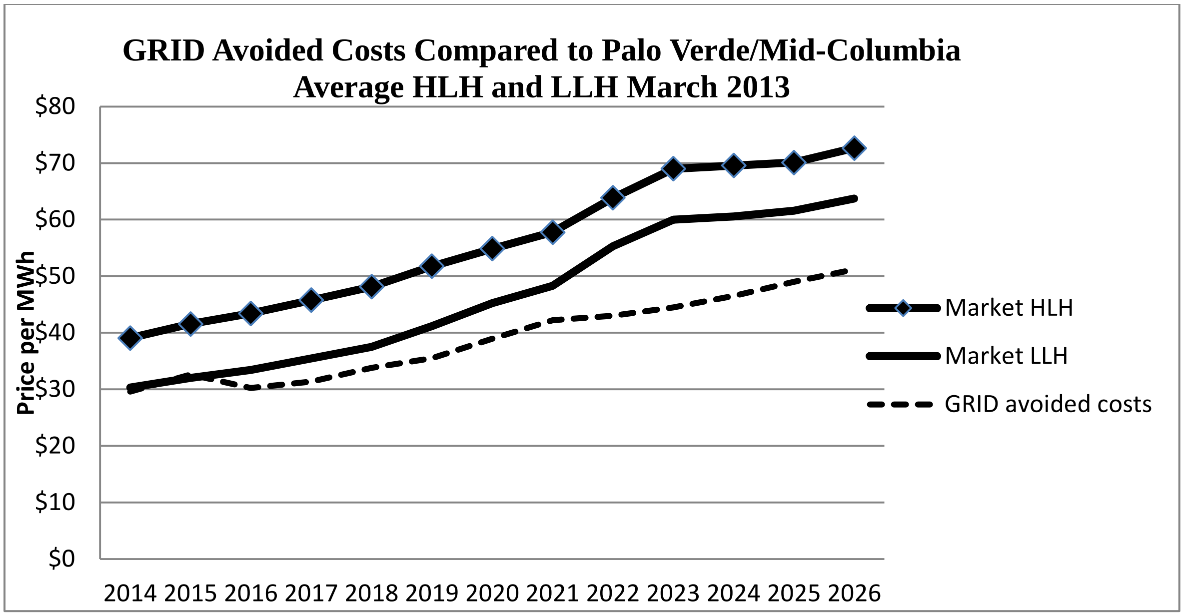
Wind Integration Cost
Escalation Rates

2020	14.5%
2021	15.6%
2022	17.7%
2023	15.0%

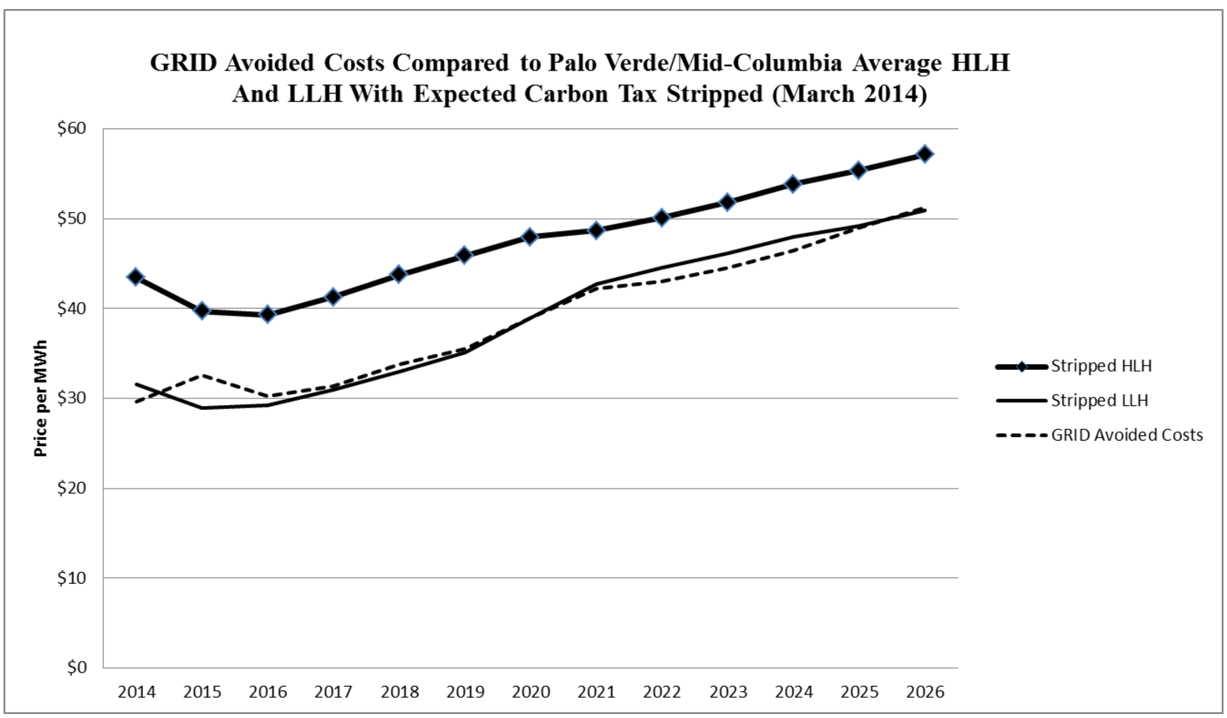
The Short Run

The following chart compares market prices with GRID avoided energy costs, from Table 2A Base Load[7], over the "Short Run" period of occasional capacity sufficiency. I don't mean to imply that the difference is necessarily due to GRID itself. GRID is applied to avoided cost calculations using rules that may influence the outcome. The truth is that I don't know how GRID comes up with these numbers. Many of the displaced resources in the Schedule 38 filing[8] are HLH Front Office transactions. In any case, it looks like GRID does not think much of the power produced by a Qualifying Facility. These GRID values are not the prices available to a flimsy, fly-by-night renewable energy operation; they are the prices offered to a "Base Load" facility in Table 7.

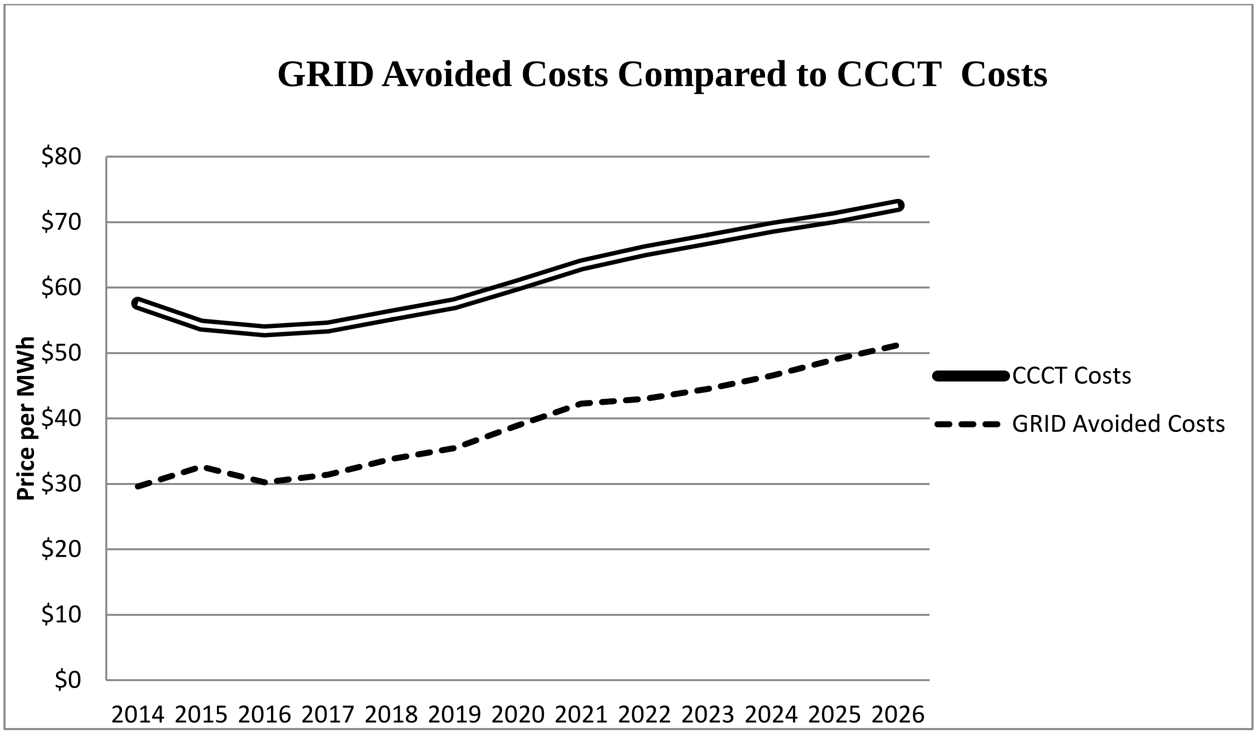
[6] Calculated from IBID Exhibit A Table 12
[7] IBID Exhibit A Table 7
[8] Appendix A PacifiCorp Avoided Cost (GRID and Differential Revenue Requirement) Model Updates through February 2014 Docket No. 03-035-14



I think that we can see what is happening when we compare GRID to the March 2014 FPC that has had carbon tax costs removed. GRID hugs *this* LLH line. Many of the displaced resources in Schedule 38 are HLH, so I'm surprised that GRID couldn't do better, even with this bold assumption.



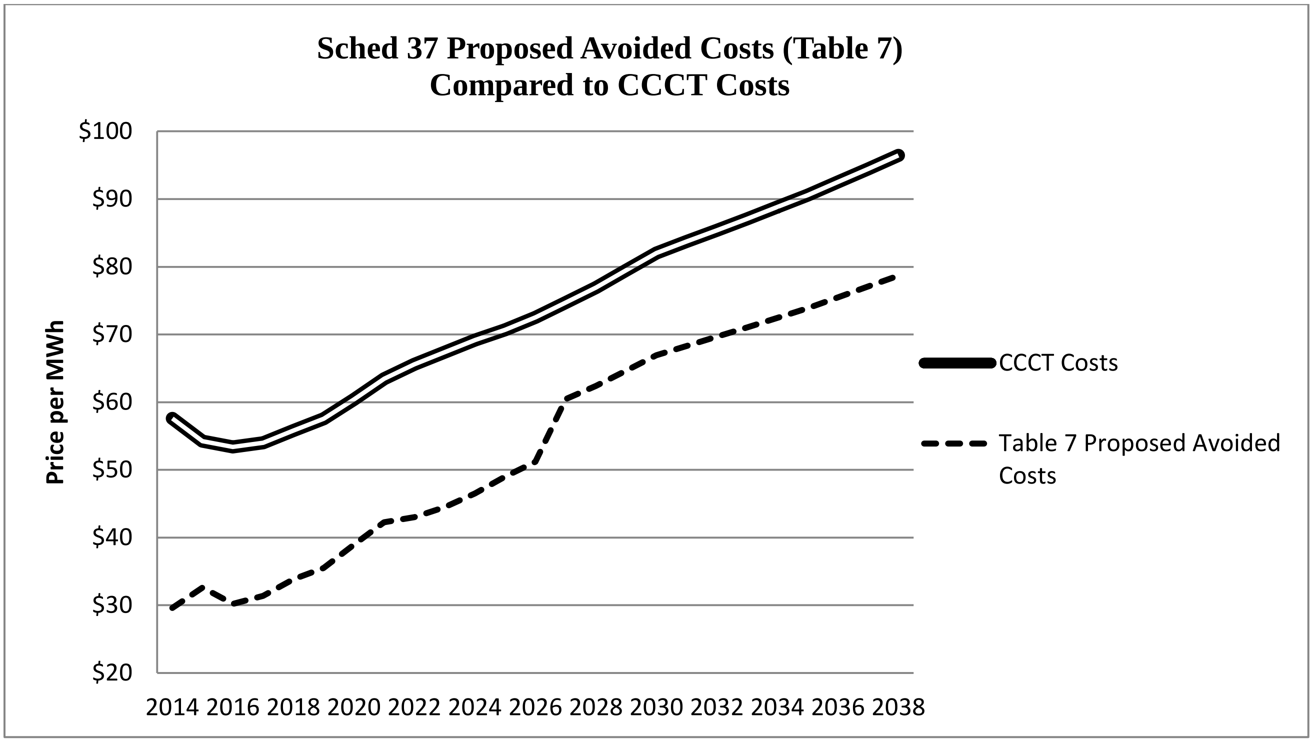
Also, remember that market prices are currently very low. In Chart 1, CCCT costs track the 2013 Forward Price Curve HLH line. If we compare GRID avoided costs directly to CCCT costs, the results are even more discouraging.

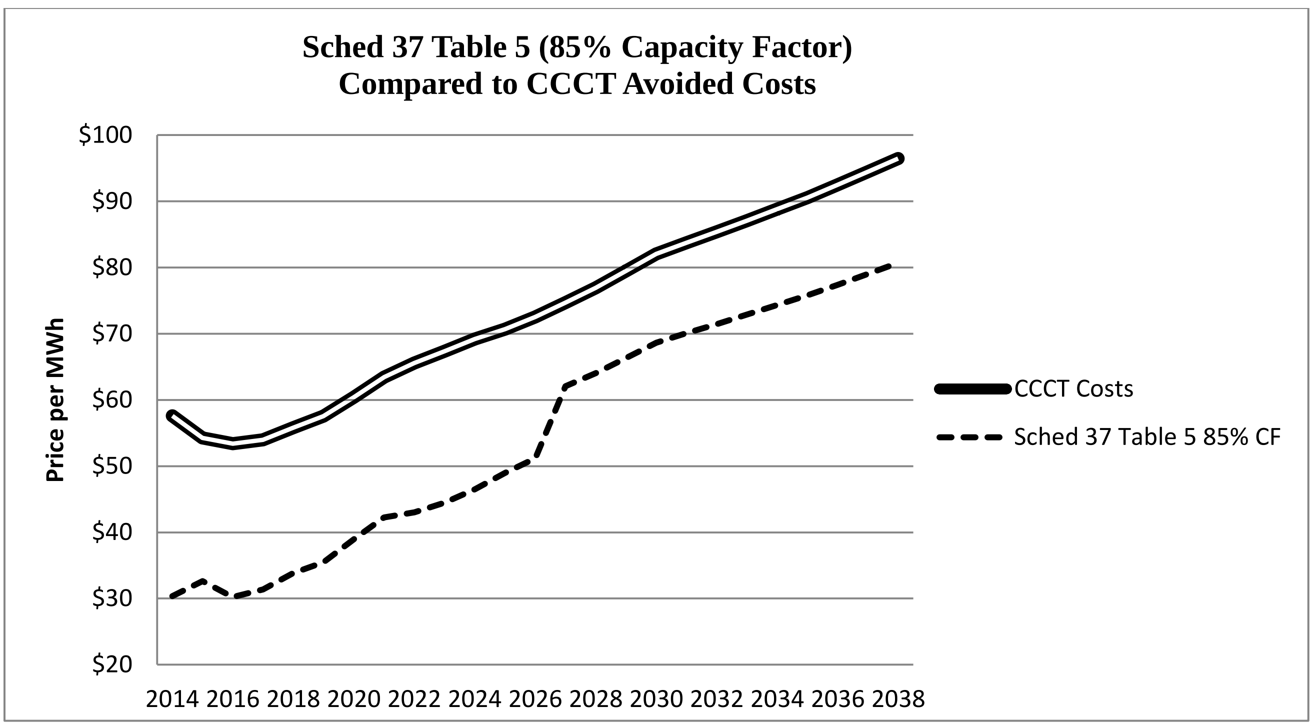


The CCCT resource cited in Schedule 37 is one of the most cost-efficient energy resources available, and natural gas price assumptions are in the dumps, to put it mildly. If a CCCT is out of the question at Schedule 37 rates, what technology makes sense? If anyone has a suggestion that does not involve cold fusion, please get in touch.

The Long Run

The following two tables extend the comparison through the 2027-2038 time frame for results using the old method (from Table 5) and the new method (from Table 6). They are not quite identical. The step-up in the "Base Load" line at year 2027 on the chart illustrates the addition of Schedule 37 capacity credit, coincident with the online target date for the CCCT. It is easy to see that "Base Load" avoided costs are still far below actual expected costs. The original Table 7 calculation method (using Table 5) and the new method (using Table 6), are very similar, but not identical.





Looking for a Better Recipe

The long term errors can easily be corrected. The proposed avoided costs in Table 7 are derived from values on the Tariff Page, which in turn are derived from values on Table 6A. The Table 6A calculation that allocates capacity costs to HLH hours in cells W28:W39 use a kW-yr. to MWh conversion formula that assumes a 92.7% capacity factor (the CCCT claimed peak capacity factor). The real effect of this calculation is to determine the capacity cost / MWh as if the facility was operating at a 92.7% overall capacity factor, spreading the annual capacity cost among many more MW hours of production than the plant would actually produce over the course of the year. This makes the capacity cost/ MW hour look lower than it actually is.

The correct calculation can only use the *average* capacity factor, 51.9%. The rest of the formula correctly allocates the cost/MWh to HLH hours. Using any other number will produce incorrect results, regardless of the capacity factor of the qualifying facility.

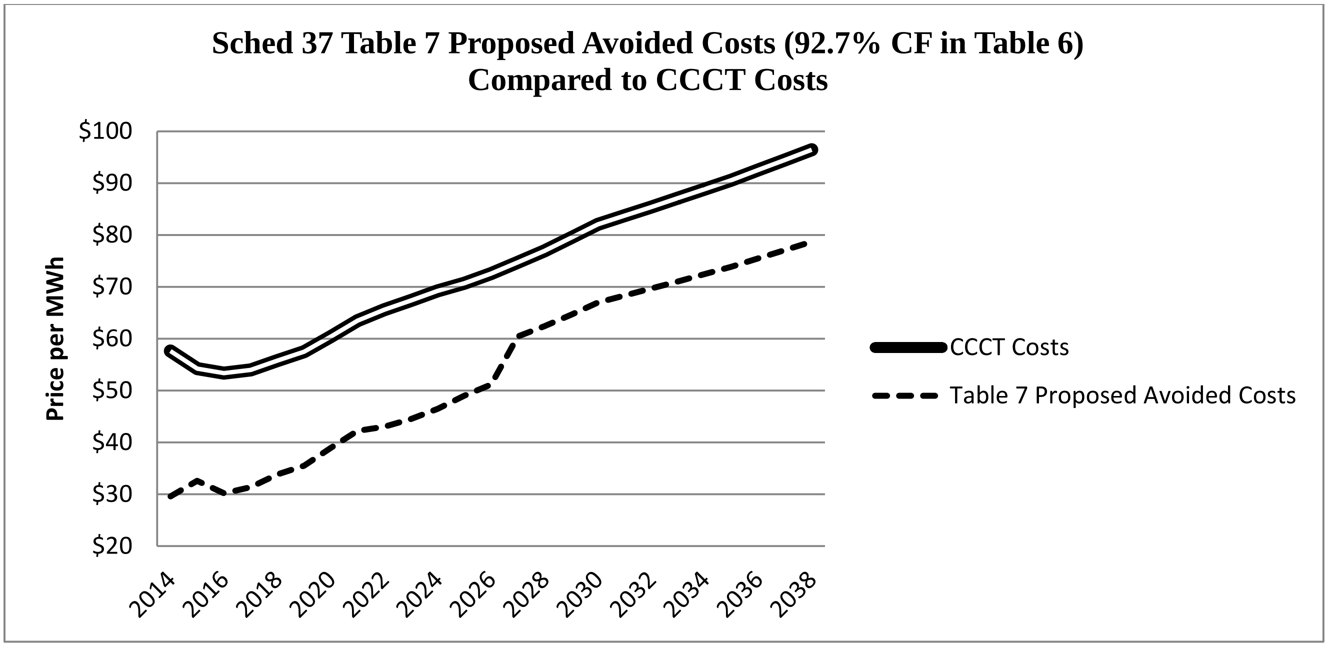
Most of the projects in the Schedule 37 and 38 queues are low capacity factor renewable energy projects. Why would we want to pay them more per MWH than we would pay a higher capacity factor project? I personally believe that there are many reasons that a renewable energy project might be worth more than a conventional project, but a light capacity factor is not one of them. I will explain how you can demonstrate this problem for yourself a little later.

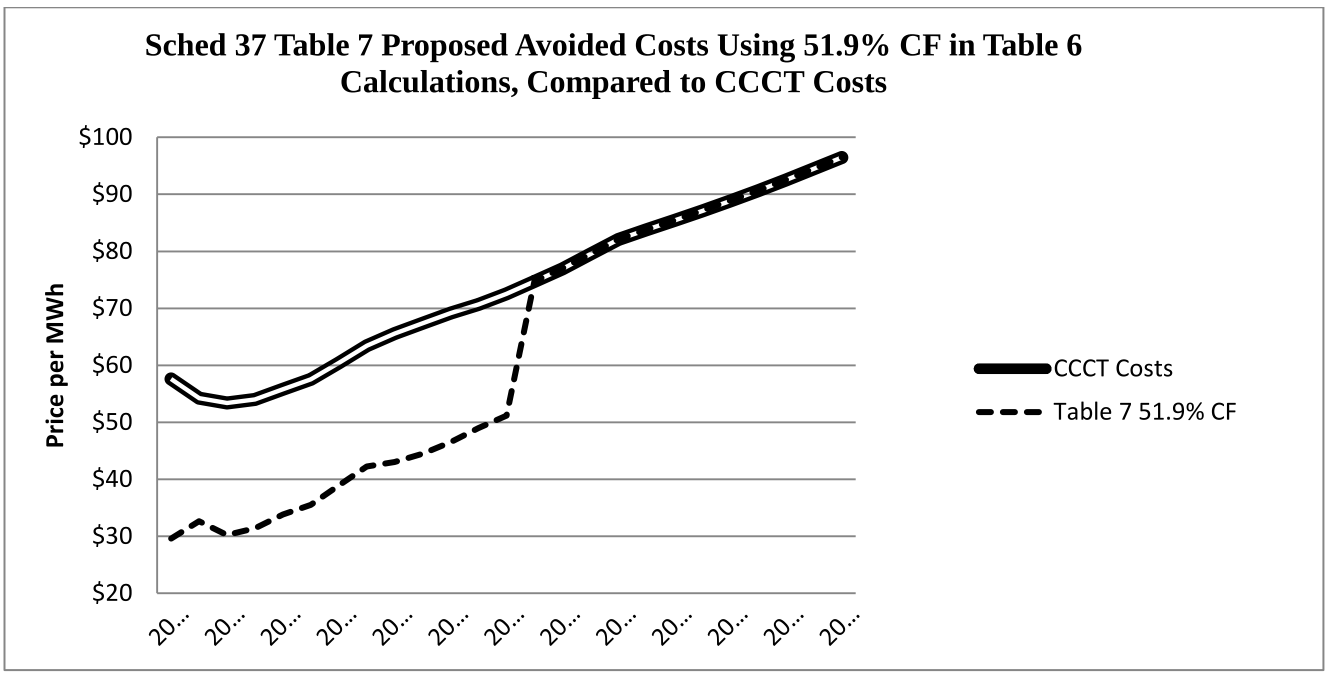
The intermingling of CCCT and SCCT costs to determine $/kW-yr. (prior to this calculation) has not been changed.

Original calculation: = Round(($/kW-yr.)/(8.76*(peak capacity factor)*(%HLH hours)),2)

Correct calculation: = Round(($/kW-yr.)/8.76*(average capacity factor)*(%HLH hours)),2)

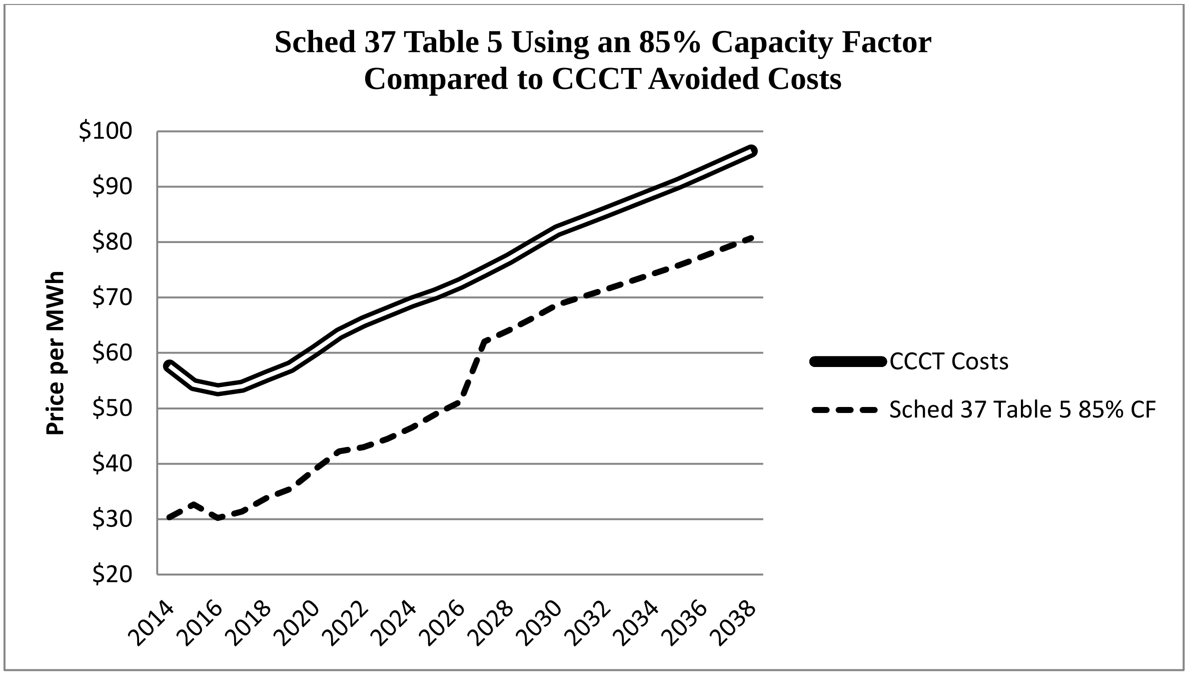
The results are compared on the following charts:

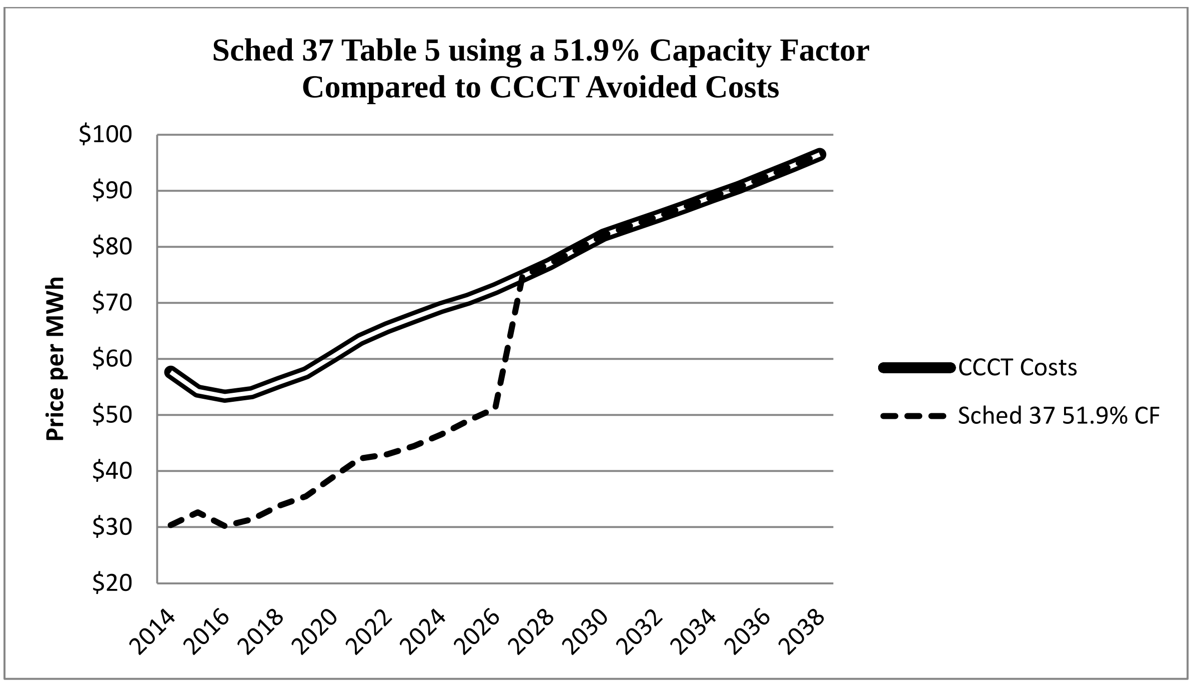




The same error occurs on Tables 6B, C and D.

The original Table 5 method can also be easily corrected. The CCCT plant obviously does not operate at an 85% capacity factor, but at a 51.9% capacity factor. Adjusting cell R7 to a 51.9% capacity factor in Table 5 yields results that can be compared in the following charts:





I recently requested that an apparent error be corrected in the most recent Schedule 38 filing[9]. The Division replied that the calculation was correct at the stated capacity factor[10]. My concern was that the stated 85 % capacity factor is not correct, and that the new calculation freezes the

[9] Docket 14-035-40, Email correspondence from Robert Millsap

[10] Docket 14-035-40, Comments from DPU

levelized payment at this incorrect level. The differences in outcomes for various capacity factor assumptions are very large. Three examples are provided in Table 5 of the Schedule 37 filing, but they all produce results that understate capacity costs, compared to the 51.9% CF of the CCCT. One can test the variation by adjusting Cell R7 in Schedule 37 Table 5, and then observing the annual values in Cells R28:R39. Try 35% value for a wind farm, or perhaps a 22% value for a fixed solar facility. The effect on annual capacity payments is tremendous.

Even with these changes, GRID-generated energy valuations for the first 13 years are so far below market values that it is hard to imagine producing or selling power at those prices. As a ratepayer, I would be very interested in any project that could match or beat Mona hub prices (including of course, the carbon tax).

The Commission must be growing weary of Schedules 37 and 38 and of my observations in particular. I am very sorry to keep stirring the pot. As a positive, QFs clearly have the potential to provide very effective and valuable long-term hedging opportunities for ratepayers, at no cost; free insurance, if-you-will. Because of time constraints, I must apologize for only being able to attach somewhat-disorganized edits to the Schedule 37 Exhibit A with these comments. Once again, I have to thank the Commission for their commitment to transparency and open communication. I deeply appreciate the opportunity to make these comments.

Submitted Respectfully, Robert Millsap

This document will be submitted electronically to:

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