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August 22, 2013

Via Electronic Filing and FedEx

Public Utility Commission
Attn: Filing Center
3930 Fairview Industrial Drive SE
PO Box 1088
Salem, OR 97308

Re: Docket No. LC 57 Preliminary Comments of Sierra Club

Please find enclosed the original and five (5) copies of Sierra Club's Preliminary Comments in the above-referenced docket.

The redacted version of this document has been e-filed with the Commission and served upon parties via email. The confidential version of this document is being filed with the Commission via FedEx and served pursuant to Protective Order No. 13-095 upon all eligible party representatives via USPS.

Please let me know if you have any questions. Thank you.

Respectfully submitted,

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Sierra Club's Preliminary Comments on PacifiCorp 2013 Integrated Resource Plan (Oregon Docket LC 57)

August 22, 2013

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1.1. Overview

On behalf of the Sierra Club, Synapse Energy Economics, Inc. provides these preliminary comments. The PacifiCorp 2013 IRP represents large strides in the technical construction of an integrated plan with transparency in mechanism and assumptions. The IRP mechanism is broadly consistent with the process used in the recent Naughton 3 and Bridger 3 & 4 CPCN proceedings in Wyoming, wherein most Company assumptions were open to intervenor examination. PacifiCorp has been responsive to concerns from past IRP, and improvements in transparency and process appear to have resulted in an improved process.

Importantly, however, the 2013 IRP leaves significant holes and unanswered questions that are fundamental to PacifiCorp's planning environment, along with hard choices the Company and decision makers will face in the coming years. The IRP tackles several key questions, some of which are answered robustly; others, however, simply show that the Company's modeling stopped well short of providing a complete picture. Amongst the overarching questions that must be resolved are:

1. Which of the Company's coal units are at risk with low gas prices and a price on carbon dioxide emissions, and if major expenditures should be pursued at those coal units;
2. If finalized regional haze rules could render additional coal units non-economic;
3. If the Company requires new thermal generation infrastructure in the near future;
4. If PacifiCorp can comply with RPS in Washington, Oregon, and California via the purchase of RECs alone, or if the Company needs additional physical resources;
5. If there is a benefit to building significant transmission infrastructure in Wyoming and Idaho, and from Wyoming to Utah;
6. To what degree DSM should be expected to contribute substantially to the PacifiCorp portfolio.

Each of these questions is crucial to the Company's next steps, and yet some are not answered with any real certainty, or even sufficient information. Sections below detail which of these questions remain open and in need of additional analysis.

Identifying which of the Company's coal units are at risk is the overarching issue in this IRP. In fact, under one of the Company's three commodity price scenarios, nearly every coal unit retires by 2023, with three-quarters of those units retiring before 2020. This scenario stands in stark contrast to the Company's base case, in which only the foregone Naughton 3 and Carbon plant, as well as the Cholla 4 unit, are retired before the end of their depreciable life. The early retirement of the PacifiCorp coal fleet turns the Company from a coal-dominated utility to a gas-dependent utility, with presumably significant implications for the Company's investments and decisions that will occur in the next months to near-term years. This conclusion is an extraordinary result that is minimized in the 2013 IRP.

Ultimately, the IRP presents readers and regulators with a binary choice: believe the Company's base case and dismiss the risk of significant additional coal unit retirement, or consider the potential impact of a more extreme scenario and start planning for replacement capacity. Missing from this analysis is: the level of risk faced by any given coal unit; the threshold of gas, coal, or CO_2 prices; and capital expenditures that could trigger the decision to retire a coal unit rather than pursue additional costly expenditures.

Compounding this uncertainty are recent developments showing that the Company's stress case for reviewing regional haze compliance obligations was insufficient, casting further doubt on the coal plant retirement study. Less than a month after PacifiCorp finalized its 2013 IRP, the US EPA proposed to reject the Wyoming Regional Haze State Implementation Plan (SIP) and require more stringent controls than PacifiCorp relied on in the IRP. In particular, the IRP did not review the impact of higher-cost controls at Naughton units 1 & 2, or Dave Johnston units 3 or 4. EPA is expected to issue a final BART rule for Wyoming in November 2013. Similarly, PacifiCorp and the public await a final EPA BART proposal to replace the Utah regional haze SIP, which may ultimately require a more stringent set of controls than calculated in the IRP.

Finding a middle ground between PacifiCorp's postulated choices of a "base case" or their more extreme case can be readily resolved in an update to this IRP. Without significant new work, the Company can put forth a series of analyses that (a) review the complete set of combinations of gas and CO_2 price ranges, (b) update core assumptions to include likely costs of compliance with EPA proposed regulations, (c) disclose or provide analysis to demonstrate either breakeven pricing for CO_2, gas, and/or coal prices or otherwise indicate the risk faced by individual coal units in the near-term and further future.

1.2. PacifiCorp must affirmatively examine the impact and recovery from significant coal unit retirements.

PacifiCorp ran "94 unique core case scenarios" developed to test a range of commodity prices (gas, coal and CO_2) with different assumptions about RPS compliance and the stringency of final regional haze rules, overlaid on five transmission development scenarios. Ultimately, the differences between these scenarios resulted in two key sets of differences: retirements of either 3, 4, or 20-21 coal-fired units (replaced with natural gas); and either no new wind or minimal wind until 2022.

From a portfolio perspective, the 94 scenarios can be compressed into three basic blocks defined by their commodity prices: (a) reference case gas and CO2 prices, (b) low gas price with high CO2 price, or (c) high gas price with low CO2 price.

From the perspective of coal-plant retirement dynamics, neither the RPS nor the transmission scenario nor the stringency of the regional haze rule materially change which units retire before the end of their depreciable life. However, the commodity price establishes wide endpoints: either only announced plants retired or almost all coal units retired (see Table 1, below).[1] For most observers, the idea that one of the endpoints could result in the retirement of nearly all of PacifiCorp's units appears extreme, and indeed PacifiCorp rejects these endpoints because they don't perform favorably under mean baseline conditions.

[1] Source: OPUC 105 2013IRP Study_Revised_EG1_4-18-13.xlsx

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Table 1. Coal unit retirements identified in the 2013 IRP, Transmission Scenario EG-1. Scenarios ordered by number and timing of retirements.

	Strin RH, Lo Gas, Hi CO2 & Coal, No RPS	Strin RH, Lo Gas, Hi CO2 & Coal, With RPS	Base RH, Lo Gas, Hi CO2 & Coal, No RPS	Base RH, Lo Gas, Hi CO2 & Coal, With RPS	Reference, No RPS	Reference, State RPS	Reference, State+Federal RPS	Strin RH, Med Gas & CO2, Med Coal, No RPS	Strin RH, Med Gas & CO2, Med Coal, With RPS	Base RH, Hi Gas, No CO2, Lo Coal, No RPS	Base RH, Hi Gas, No CO2, Lo Coal, With RPS	Strin RH, Hi Gas, No CO2, Lo Coal, No RPS	Strin RH, Hi Gas, No CO2, Lo Coal, With RPS
Existing Plant Retirements/Conversions	EG-1 Case C-08	EG-1 Case C-09	EG-1 Case C-04	EG-1 Case C-05	EG-1 Case C-01	EG-1 Case C-02	EG-1 Case C-03	EG-1 Case C-10	EG-1 Case C-11	EG-1 Case C-06	EG-1 Case C-07	EG-1 Case C-12	EG-1 Case C-13
Naughton3 (Early Retirement/Conversion)	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015
Carbon1 (Early Retirement/Conversion)	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015
Carbon2 (Early Retirement/Conversion)	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015
Cholla1 (Early Retirement/Conversion)	2017	2017	2017	2017	2025	2025	2024	2025	2025				
Hunter1 (Early Retirement/Conversion)	2015	2015	2015	2015									
Hunter2 (Early Retirement/Conversion)	2018	2018	2021	2021									
Hunter3 (Early Retirement/Conversion)	2020	2020	2020	2020									
JBridger1 (Early Retirement/Conversion)	2018	2018	2023	2023									
JBridger2 (Early Retirement/Conversion)	2018	2018	2022	2022									
JBridger3 (Early Retirement/Conversion)	2016	2016	2016	2016									
JBridger4 (Early Retirement/Conversion)	2017	2017	2017	2017									
Huntington1 (Early Retirement/Conversion)	2018	2018	2022	2022									
Huntington2 (Early Retirement/Conversion)	2018	2018	2021	2023									
Naughton1 (Early Retirement/Conversion)	2020	2020	2020	2020									
Naughton2 (Early Retirement/Conversion)	2019	2019	2019	2019									
Wyodak1 (Early Retirement/Conversion)	2023	2023	2020	2020									
Colstrip3 (Early Retirement/Conversion)	2020	2020	2020	2020									
Colstrip4 (Early Retirement/Conversion)	2021	2021	2019	2019									
Johnston1 (Early Retirement/Conversion)	2020	2020	2020	2020									
Johnston2 (Early Retirement/Conversion)	2018	2018											
Johnston3 (Early Retirement/Conversion)	2022	2022	2022	2022									
Johnston4 (Early Retirement/Conversion)													
Gas	Low	Low	Low	Low	Med	Med	Med	Med	Med	High	High	High	High
CO2	High	High	High	High	Med	Med	Med	Med	Med	Low	Low	Low	Low
Coal	High	High	High	High	Med	Med	Med	Med	Med	Low	Low	Low	Low

*PacifiCorp is the owner of Cholla Unit 4. As far we are aware, the listing of Cholla 1 in Table 1 is a typographical error contained in PacifiCorp's output files.

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1.3. PacifiCorp's "high" CO_2 price is lower than the EPA's social cost of carbon.

The Company's low gas/high CO_2 endpoint is neither outside the range of reason, nor even an extreme test case. For example, the low gas price trajectory maintains a long-term pricing above prices seen in 2012.[2]

The "high" carbon price both starts later and achieves a lower price trajectory than baseline estimates used by other utilities. Notably, even the "high" carbon price of PacifiCorp is lower than the mid social cost of carbon (SCC) price recently published by the EPA (see Figure 1, below).[3]

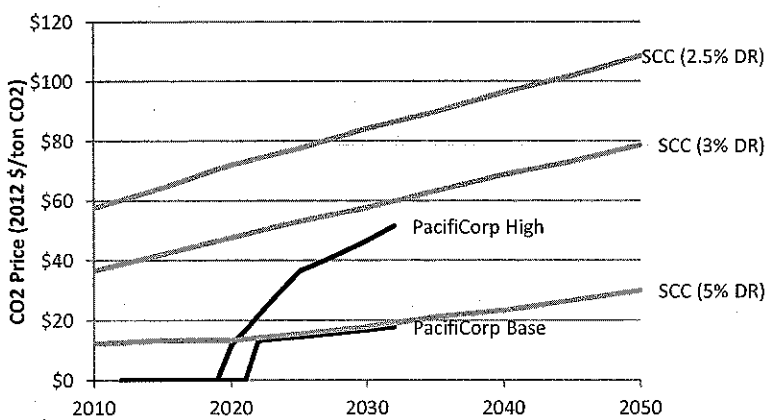

Figure 1. EPA Social Cost of Carbon (SCC) at different social discount rates vs. the PacifiCorp CO_2 price forecasts.

The EPA and other agencies use the social cost of carbon (and other externality estimates) to inform the cost-effectiveness of rulemakings; indeed, in recent years, EPA has successfully supported its rulemakings on the basis of their cost effectiveness relative to social benefits. In conjunction with the President's highly public announcements on climate change directing EPA to regulate CO_2 under the existing source provision of the New Source Performance Standard (NSPS), it is safe to assume that the SCC may be used to justify stringent carbon reduction policies with price impacts at or above the "high" carbon price projected by the Company. PacifiCorp could very well experience low gas prices and/or "high" carbon prices within the foreseeable future.

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[2] Although, this pricing is below those expected by analysts and traders in the next few years, and about a dollar below the most recent Federal estimate from the Energy Information Administration (EIA) AEO 2013 report.

[3] See US EPA: The Social Cost of Carbon. http://www.epa.gov/climatechange/EPAactivities/economics/scc.html. The three different SCC trajectories shown here represent three different estimates of a social discount rate, ranging from a shorter-run business-like perspective of 5% to a multi-generational perspective of 2.5%. The lower discount rate capture the cost implications of impacts that occur decades from now due to activities today.

The combination of low gas price and the Company's "high" CO_2 price results in numerous coal plant retirements ahead of major expenditures – including environmental retrofits required under either the best available retrofit technology (BART) or reasonable progress provisions of the regional haze rule. Therefore, many of the expected retirements occur even prior to the onset of a carbon price.

Ultimately, regardless of the performance of these high retirement scenarios relative to the baseline scenarios, the simple fact that a reasonable set of parameters result in massive coal plant retirements indicates that the Company must seriously review the risks its coal fleet faces, and craft a strategic plan for transitioning to an inevitable non-coal economy. While the wholesale retirement of the entire fleet may not ultimately be the most effective outcome for the Company, the results of this IRP suggest that it is well within the range of reason and should not be discounted simply because they do not perform as well in the Planning and Risk module.

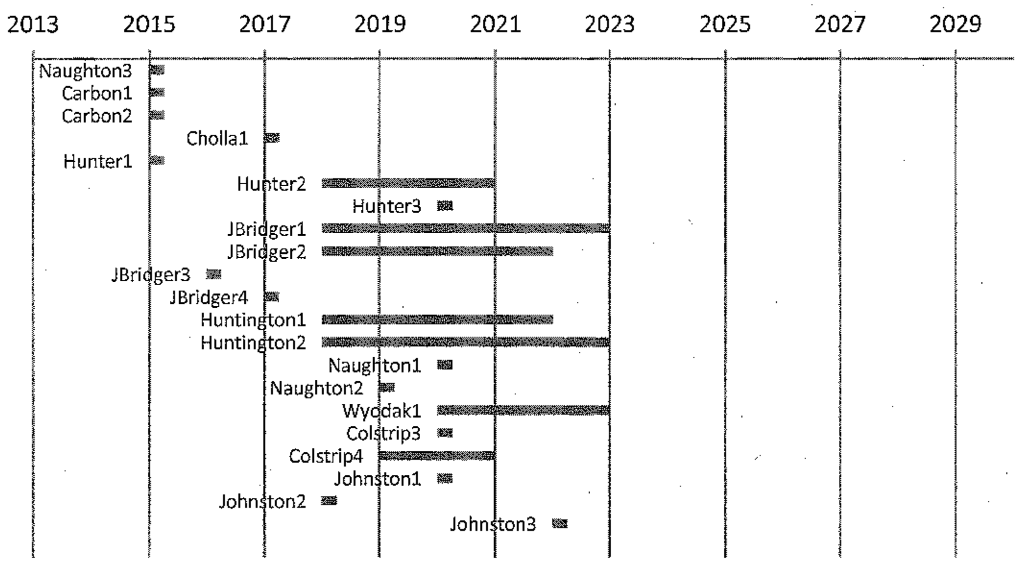

Figure 2. Coal unit retirement years identified in the 2013 IRP, Transmission Scenario EG-1 under low gas / high CO2 price scenarios. Units with a range indicate that scenarios identified different retirement years. 4

1.4. PacifiCorp's IRP scenarios are highly repetitive, and do not provide adequate resolution on risk to the Company's coal plants.

PacifiCorp's 94 scenarios can ultimately be condensed into three fundamental sets defined largely by their commodity price assumptions. As noted above, one of the features of these three sets is that the commodity price set that is most favorable to coal plant retirement results

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[4] Source: OPUC 105 2013IRP Study_Revised_EG1_4-18-13.xlsx

in the retirement of nearly <u>all</u> of the units, while the base case results in the retirement of only announced units (Naughton 3 and Carbon 1&2).

In only running these three sets of scenarios, PacifiCorp missed a critical opportunity to explore, in a public planning framework, the sensitivity of their system to anything except for the most extreme test cases. In addition, there is no marker or reported information that would allow stakeholders or regulators to understand the degree of risk faced by any given coal unit in the fleet. System Optimizer, as a discrete linear program, reports a single "optimal" solution – if a single element is more economic than the next best choice by $1 or by $100,000,000, System Optimizer will still choose that element. In this reporting of book-end scenarios, stakeholders are unable to determine the vulnerability of PacifiCorp's coal units except in a single bookend.

Section 1.8 (below) discusses how the System Optimizer model may not be reporting future poor performance for the Company's coal units and presents a rough estimate of the economic condition of the Company's coal units. This type of information is not presented in the current IRP, and cannot be directly derived from the Company's System Optimizer model.

To remedy this situation, PacifiCorp must provide two additional analyses as soon as possible:

1. Run core scenarios with other combinations and permutations of the low/mid/high gas prices, rather than just the three provided in this IRP. The schematic below shows where new runs must be completed.[5] These scenarios will help provide clarity regarding whether multiple plants are also vulnerable under less dire commodity price futures.

		Gas Price		
		Low	**Mid**	**High**
CO_2 Price	**Low**	?		**Retire None**
	Mid	?	**Base**	
	High	**Retire All**	?	?

[5] From a coal asset evaluation perspective, running mid gas/low CO_2 or high gas/mid CO_2 scenarios are not additionally illustrative.

2. Provide a metric by which stakeholders and regulators can determine or estimate the threshold price of gas and/or CO_2 that renders any given coal unit non-economic.

PacifiCorp's "screening model" in the 2011 IRP provided one such mechanism of evaluating the cost effectiveness of individual coal units. An updated version of this model with new capital and OFPC assumptions could, in large part, satisfy the requirement of the second metric.

1.5. The Planning and Risk stress test favors reference case outcomes.

The Planning and Risk (PaR) module used by PacifiCorp has both advantages and drawbacks. The module allows the Company to test each portfolio against an uncertain range of gas and market energy prices, as well as demand forecasts and forced outage rates. The module returns a series of present value revenue requirements (PVRR) for each of 100 random iterations, from which the Company derives an expected value (the average) and a risk metric (the 95th percentile).

The disadvantage of the PaR module is that it is, by design, biased towards the selection of the reference or base case. The PaR module, while implementing a range of "random walk" commodity prices, has an average price trajectory that is very close to the base case commodity prices (see example of gas prices in Confidential Figure 3, below). The net effect is that the average outcome of the PaR module reflects essentially a run with base case commodity prices. Frankly, this approach is disingenuous. It is clear that a reference case outcome will always prevail – scenarios optimized under different commodity prices are, by design and definition, not optimal in a reference case environment. Further, the parameters of the PaR model allow commodity prices to range well outside of reasonable or predicted boundaries. Since only market and gas prices are stochastically determined, this modeling approach results in massive upside risks for gas-heavy outcomes, and a narrow band of risk for coal-heavy outcomes. Thus, adjusting PVRR for "risk" essentially results in down weighting gas portfolios.

[redacted]

Confidential Figure 3. High, low and base (OFPC 9.2012) gas prices used in the 2013 IRP SO model, as well as stochastic gas price trajectories used in PaR model.

When it comes to understanding the implications of the IRP for PacifiCorp's existing fleet and new resource decisions, the "risk adjusted PVRR" may not be an appropriate measure, particularly in situations where there is a binary choice between two very different trajectories. Rather than attempting to determine which type of outcome is more likely to succeed under base conditions, the Company should advance a theory of the likelihood, and risk, of a particular outcome transpiring and the risks incurred by choosing a particular pathway – in other words, a "no regrets" analysis.

1.6. The Company must retire Cholla unit 4.

On December 5, 2012, the EPA promulgated a final Federal Implementation Plan (FIP) for Regional Haze in Arizona (77 FR 72511). The FIP disapproved components of Arizona's State Implementation Plan (SIP), and sets an emissions limit of 0.055 lbs. NOx/MMBtu on a rolling 30-operating-day limit at Cholla Units 2-4. EPA's rule requires installation of selective catalytic reduction technology ("SCR") at PacifiCorp's Cholla unit 4.

However, both the base case and low gas/high CO_2 commodity price scenarios result in the early retirement of Cholla unit 4. The Company's base forecast predicts that any expenditures made by 2017 would have less than eight years to recover their costs prior to the retirement of the unit – or that either the Company or ratepayers would be saddled with stranded costs. The Company's low gas/high CO_2 case shows that the retrofit should not be made in the first place, and the unit should be scheduled for retirement in 2017.

Given the poor economic outcome for Cholla, the Company decided to sue EPA on its BART determination for the plant. Setting aside PacifiCorp's litigation, prudent planning still requires the Company to analyze retiring the unit.

It is recommended that the action plan reflect an affirmative planning stage from PacifiCorp to disclose how or if the Company plans to ensure that ratepayers are not saddled with unnecessary retrofit expenditures.

1.7. PacifiCorp scenarios omitted likely regional haze resolution in Wyoming.

On June 10, 2013, EPA published a proposed Federal Implementation Plan (FIP) for Regional Haze in Wyoming (78 FR 34738). The proposed FIP indicates that the IRP's Stringent Regional Haze scenarios are actually less stringent than EPA's proposed rule. Table 2, below, shows EPA's proposed FIP relative to the base and stringent cases, and highlights units that are likely to have more stringent (i.e., costly) compliance requirements than anticipated by the Company in the stringent case.

Table 2. PacifiCorp regional haze assumptions for the Base and Stringent cases, compared against the June 2013 Proposed FIP for Wyoming.

Coal Unit	State	Base Regional Haze		Stringent Regional Haze Stringent Regional Haze		EPA Proposed FIP (WY)	
		Technology*	Year	Technology*	Year	Technology*	Year***
DJ 1	WY			LNB	2016	LNB w/OFA w/OF A	7-31-2018 (was 2016)
DJ 2	WY			LNB	2018	LNB w/OFA	7-31-2018 (was 2018)
DJ 3	WY			SNCR	2017	SCR	2019
DJ 4	WY					SNCR	2019
J. Bridger 1	WY	SCR	2022	SCR	2017	SCR**	2019
J. Bridger 2	WY	SCR	2021	SCR	2017	SCR**	2019
J. Bridger 3	WY	SCR	2015	SCR	2015	SCR	2019
J. Bridger 4	WY	SCR	2016	SCR	2016	SCR	2019
Naughton 1	WY					SCR	2019
Naughton 2	WY					SCR	2019
Wyodak	WY			SNCR/SCR	2017/2025	SNCR	2019
Hunter 1	UT	BH, LNB	2014	BH, LNB/SCR	2014/2018	*Unknown*	
Hunter 2	UT	SCR	2023	SCR	2017	*Unknown*	
Hunter 3	UT	SCR	2024	SCR	2020	*Unknown*	
Huntington 1	UT	SCR	2026	SCR	2018	*Unknown*	
Huntington 2	UT	SCR	2023 20	SCR	2017	*Unknown*	
Hayden 1	CO	SCR	2015	SCR	2015		
Hayden 2	CO	SCR	2016	SCR	2016		

Craig 1	CO	SNCR	2017	SNCR/SCR	2017/2024	
Craig 2	CO	SCR	2016	SCR	2016	
Colstrip 3	MT			SCR	2023	
Colstrip 4	MT			SCR	2024	
Cholla 4	AZ	SCR	2017	SCR	2017	

**SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse*
***EPA presented two options for JB 1 & 2: first approach – accept current technology as BART, SCRs on both in the 2021-2022 timeframe; second approach – SCRs on both in the 2018-19 timeframe*
**** Estimate of implementation deadline "as expeditiously as practicable, but no later than five years after EPA finalized action on our proposed FIP." Assumes finalization by January 2014.*

The scaling up from an SNCR to SCR at Dave Johnston 3 is a relatively expensive additional cost that could render DJ3 non-economic in the near-term. The addition of an SNCR at DJ4 adds capital and operational costs that similarly could tip the balance of this unit.

PacifiCorp's failure to anticipate a requirement for SCRs at Naughton 1 and 2, and failure to model the economic impact of this retrofit requirement reaffirms a long-running inability of the Company to assess the reasonable risks of environmental regulations at this plant. In April and May of 2011, Sierra Club filed testimony in rate cases in Wyoming and Utah (respectively) pointing out that while the regional haze rule was not yet finalized for those states, there was a strong possibility that SCRs to control NOx emissions would ultimately be required for the Naughton 1 and 2 units. PacifiCorp refused to acknowledge this very real risk. In June of 2012, Sierra Club filed testimony in a subsequent Oregon rate case citing evidence that the Company had considered the risk (or even likelihood) of an SCR requirement at Naughton 1 and 2, but did not reflect these costs when reviewing the cost efficacy of SO_2 controls. Again, PacifiCorp insisted that "the Company [did] not anticipate installing SCRs on Naughton 1 or 2 in the future." The Oregon PUC agreed with Sierra Club that a failure to consider reasonably likely costs constituted imprudent planning, and disallowed a portion of the retrofit costs. Today, the EPA's proposed regional haze FIP for Wyoming requires SCRs at Naughton 1 & 2, yet the Company has continued to ignore these cost implications.

Even if the Company were to re-run the System Optimizer model and determine that Naughton 1 and 2 would continue to be economic despite the SCR requirement, allowing the installation of this equipment would clearly constitute a piecemeal approach to environmental retrofits on a grand scale: had the Company simply evaluated the likely Naughton retrofits in a comprehensive package in 2009, the ratepayers would have been spared hundreds of millions of dollars in unnecessary and wasteful expenses. If the Company re-runs System Optimizer and determines that Naughton 1 and 2 are candidates for near-term retirement, Commissions in five states will be faced with the challenge of significant stranded costs for environmental equipment just coming online today.

In a July 8 2013 IRP Technical Workshop, the Company flatly refused to consider re-running System Optimizer with the updated proposed FIP compliance requirements. According to the Company, it intended to fully challenge the outcome of EPA's final BART determination for Wyoming. In light of its likely litigation, the Company claimed it would be disadvantageous for it to provide analysis materials to IRP stakeholders if those materials could then be used against the Company in litigation, specifically citing Sierra Club as such an adversarial party. The current status is that the Company <u>will not</u> model the most likely environmental retrofit requirements. In short, PacifiCorp is withholding highly relevant analyses on grounds that it hopes to delay a final EPA rule.

1.8. PacifiCorp's coal units may pose a higher risk than portrayed in the System Optimizer model

As discussed in Section 1.4, the System Optimizer model presents both operators (i.e. the Company) and observers a single "optimal" outcome, regardless of how close the solution comes to a next best solution. There is no information presented in the IRP, nor available from the System Optimizer outputs as provided, that would allow users to estimate the degree to which a certain plan is optimal (i.e. the benefit beyond the next best solution). However, there is sufficient information to estimate the long-run performance of any given Company coal unit under assumptions presented in this IRP. Importantly, the results of a separate analysis suggest that PacifiCorp's units continue to pose significant risks of stranded costs to ratepayers or the Company.

During the 2011 IRP review, the Company created a spreadsheet-based screening model that provided a rough, but indicative view, of PacifiCorp's coal unit economics. This model accounted for and amortized fixed and capital expenditures, roughly estimated dispatch, and calculated the net benefit of operating a coal unit versus retiring and replacing that unit with an equal capacity natural gas unit. This model is admittedly insufficient for making absolute investment decisions, but is both illustrative and transparent.

Sierra Club obtained the 2011 screening model,[6] the Q1 2013 Official Forward Price Curve (OFPC) containing gas and market price forecasts from the Company,[7] and the Company's most

[6] LC 57 PAC Attach Sierra Club 1.24 CONF.xlsx

[7] LC 57 PAC Attach Sierra Club 1.6-1

recent coal price forecasts.[8] Substituting in these forecasts into the Company's screening model produced a rough estimate of how these decisions could be viewed today. Generally speaking, the model results indicated that the relative benefit of maintaining some of the coal units has improved marginally since the 2011 forecast (due primarily to lower coal price forecasts), with a few key exceptions.

The cost of implementing an SCR on Naughton 1 and 2, as required by the re-proposed EPA Regional Haze FIP for Wyoming creates a significant burden on these units. In 2012, Sierra Club argued that the Company's justification in 2009 for installing FGD in 2012 was flawed and shortsighted; even if those costs are considered sunk, the long term benefit of maintaining Naughton 1 & 2 are significantly diminished by the need to build yet additional infrastructure at the units. In 2009, the Company considered that the units might require SCRs, but dismissed this risk in their analysis, citing a low probability that the EPA would ever require such controls. Had they considered SCRs in their economic analysis at the time, Sierra Club found that the units certainly would have been considered for retirement, rather than retrofit.

Today, with the costs of the FGD now committed to ratepayers through the useful life of the plant, the additional costs of the SCR now threaten to render the units noneconomic. Imposing a cost for a new SCR at Naughton 1 and 2 of [redacted] in 2018,[9] respectively (PacifiCorp share of unit), drives these units towards an uneconomic low.

Confidential Figure 4, below, shows the cumulative present worth (CPW) of Naughton Unit 1 through the end of its current depreciable life (2029) relative to a new natural gas combined cycle unit (NGCC). The green line indicates the trajectory of this line in the 2011 IRP screening model, indicating that the unit had a value of [redacted] in 2011 (2011$, assumed retirement in 2015). Substituting in new market, gas, and coal prices, the unit has a CPW of [redacted]. Imposing the SCR cost drops the long term CPW to [redacted]. It is worth noting that this is a high-side estimate, as it assumes that Naughton would otherwise retire in 2015, rather than 2018, and would incur all fixed O&M costs through 2018 even if it were retiring, an unlikely scenario. Taking these adjustments into account could trim as much as [redacted] from the net benefit of maintaining Naughton 1 (i.e. no net benefit from 2012-2017, and a reduced cost of retirement).

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[8] LC 57 PAC Attach Sierra Club 1.5

[9] Values derived from trends as shown in LC 57 PAC Attach OPUC 29, 1st Rev., linear best fit from $/kW (PacifiCorp share) against total unit nameplate capacity; $/kw scaled to nameplate capacity of N1 & N2, multiplied by Company share of capacity.

[redacted]

Confidential Figure 4. Cumulative present worth (CPW) of Naughton 1 excluding and including SCRs, and as shown in 2011 IRP screening model.

The outcome for Naughton 2 is less dramatic, but still indicates a significant dent in the long-term profitability of the unit (see Confidential Figure 5, below). The imposition of the SCR reduces the long-run viability of the unit by at least [redacted]. Again, this analysis assumes a benefit incurred from 2012 through 2017, when in reality the analysis should start from 2018 (the last opportunity to retire the unit).[10]

[redacted]

Confidential Figure 5. CPW of Naughton 2 excluding and including SCRs, and as shown in 2011 IRP screening model.

Finally, the screening model indicates that the economics of Cholla 4 have declined dramatically, netting as a significant loss by the end of the unit's life as shown in Confidential Figure 6, below. The 2011 IRP screening model indicated that this unit was barely above water

[10] The flawed start date is a product of the screening model. The model as provided is protected, and does not allow for users to change retirement dates or analysis start dates.

as of the 2011 IRP, but with new market, gas and coal price assumptions, and a new SCR required in January 2018 by the EPA, the unit performs particularly poorly.

[redacted]

Confidential Figure 6. CPW of Cholla 4 excluding and including SCRs, and as shown in 2011 IRP screening model.

The Cholla 4 chart explains, in part, why the Company assumes in the base case that Cholla 4 would retire in 2025 – that year is the last year that the unit turns a profit. [redacted]. With the SCR in place, the unit ceases turning a net benefit in [redacted]. Again, both this analysis and the Company's System Optimizer model assume that all other fixed costs would be incurred through the unit's retirement, underestimating the benefit that could be realized of ramping down investments as the unit reaches the end of its life (i.e. no long-term investments in the last three or four years of life). Taking these benefits into account, this screening analysis would likely show an even greater benefit for the retirement of Cholla 4 in a near-term year if an SCR is required by law. There is little doubt that the Company should retire Cholla 4 immediately.

This type of information is invaluable to regulators, the Company, and stakeholders. The Company has not provided adequate information in the IRP to understand the magnitude of risk posed to ratepayers by underperforming plants, or by large scale coal expenditures. The Company must provide analyses, or analytical results from existing analyses, similar to those shown here (including underlying data and assumptions) to illustrate the degree of risk (or non-risk) posed to their existing assets.

1.9. Class 2 DSM incremental purchases fall sharply, assuming steep price curve and exhaustion of economic potential

PacifiCorp's IRP is one of few electric system planning efforts that allows demand-side measures (DSM) such as energy efficiency and demand-response to compete with supply-side resources in a system optimization model (in this case, System Optimizer). For "Class 2" DSM, broadly encompassing non-dispatchable energy efficiency, the Company established a series of DSM bundles, each with a total potential, achievable ramp rate, levelized cost, and lifetime. The System Optimizer model could choose cohorts of DSM bundles for each state in increments determined by the ramp rate and total potential, and lasting a particular lifetime.

From a planning perspective, this mechanism has a distinct advantage in that rather than having to first derive avoidable costs and then determine the amount of EE that can be acquired, the Company can allow DSM purchases to vary dynamically with the parameters of a specific scenario.

However, from a practical standpoint, this mechanism yields questionable results. The Company's model ultimately selects a declining pathway of incremental energy efficiency investments: each year, the Company's ability to obtain energy efficiency quickly decays from a high in 2013 to a low in 2032. This trend is completely antithetical to the steep and positive learning curve experienced by other states and utilities: few states would claim that they are currently at the peak of their energy efficiency investment potential, and that it will only decline from here.

Figure 2, below, shows the incremental purchases of energy efficiency (Class 2 DSM) by state in C11-EG1 (reference commodity prices with stringent environmental regulations and an intact RPS). Aside from a steady increase in incremental DSM for Wyoming, all other states show rapid declines in incremental efficiency, with the steepest declines occurring in Utah, Washington, and Oregon.

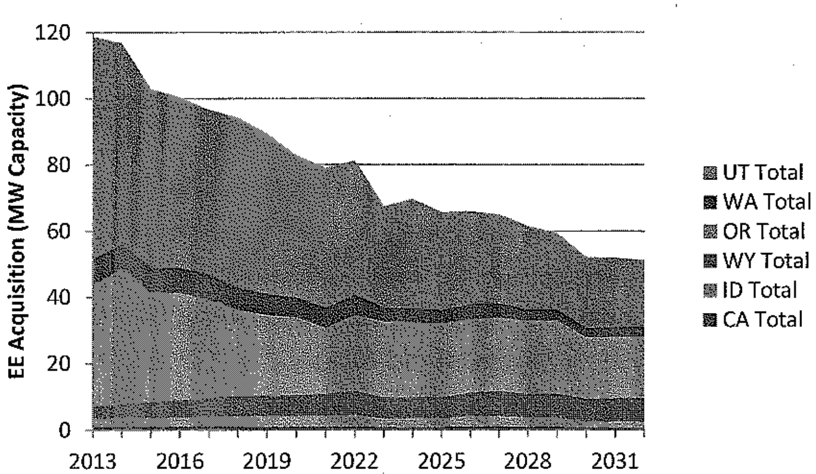

Figure 7. Energy efficiency (Class 2 DSM) incremental acquisition per year (i.e. new DSM) in C11-EG1, by state.

From a practical standpoint, this acquisition schedule results in a rapidly dropping incremental DSM pathway as a percentage of sales. In C11-EG1, the Company would expect to obtain about 0.7% of their annual sales from new energy efficiency in 2013. By 2022, the Company is down to 0.54% of annual energy sales. The fact that these numbers decline so quickly shows that the Company views itself at peak efficacy now, and cannot improve further. This approach is inconsistent with top performing utilities and states (as well as numerous established state targets around the country).

Figure 3, below, shows that the cost bundles rapidly fall off, but the low cost bundles fall out much more rapidly than the high cost bundles – i.e. PacifiCorp is indicating both some amount of cream-skimming (i.e. obtaining only low cost measures at the forefront, and attempting to pull in higher cost measures in out-years), and that once low-cost measures are exhausted, no new low cost measures will be found in the future. Again, this experience is not validated by states or utilities with long-established DSM records. Only a handful of utilities with high penetration of DSM have found costs increasing over time – and then only moderately. Most utilities with moderate to high penetrations of DSM have continued to find steady or even dropping costs of efficiency.

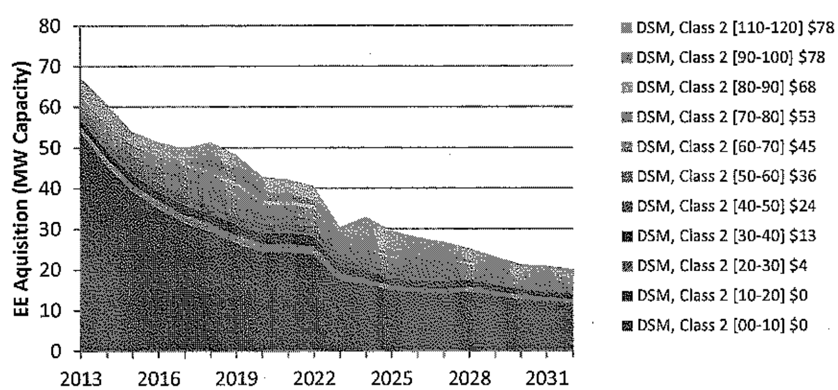

Figure 8. Utah energy efficiency (Class 2 DSM) incremental acquisition per year (i.e. new DSM) in C11-EG1, by bundle cost.

1.10. The IRP's transmission model raises significant questions about the Company's System Optimizer and PaR results.

In the 2013 IRP, PacifiCorp reviews the cost efficacy of building new transmission infrastructure through Wyoming and Idaho, and from Wyoming to central Utah. The Company proposes the use of a new tool, ancillary to the bulk of the IRP process, called the System Benefits Tool (SBT). The SBT, currently in draft form, is meant to capture incremental benefits associated with building new transmission that are otherwise not captured by the System Optimizer tool or PaR module. The SBT monetizes benefits such as reliability and loss improvements, the avoided capital costs of alternative reliability improvements, and potential benefits from wheeling power from other customers. In addition, the SBT ambiguously attempts to capture the customer benefits from reduced outages resulting from transmission improvements, as well as the monetary value of regulatory penalties against the Company from transmission outages. To be clear, these customer and regulatory benefits cannot clearly be linked to costs incurred by the Company and imparted directly to their customers – PacifiCorp's reliability is a public good, overseen and regulated by WECC rules, and impacting customers across the Western Interconnect. Strictly speaking, this cost/benefit is an externality – a type of cost not typically reviewed in other PacifiCorp planning efforts.

In its draft evaluation of Segment D (connecting Windstar to Populus, or eastern Wyoming to a hub in Idaho), the Company finds approximately $500 million in benefits from production cost improvements alone (i.e. captured by System Optimizer or PaR) and an additional $650 million in ancillary benefits not contemplated in the standard production cost model – almost 40% of which is due to the externality of customer and regulatory impacts from reduced outages. Ultimately, the Company's draft SBT suggests that the monetary benefits of Segment D ($1.1 billion) outweigh the cost of the segment ($934 million), and suggest that this value should inform their decision to build the segment.

The SBT tool raises a number of important questions that require further review:

a) Are results from System Optimizer tool or PaR sufficient to evaluate the cost efficacy of plans that have marginal differences of low hundreds of millions of dollars? If the SBT results show that hundreds of millions of dollars in savings are generally not captured by the Company's production cost model, what impacts does this finding have on decisions with marginal benefits of tens to low hundreds of millions of dollars?

b) If the presence or absence of a single transmission line is enough to swing marginal benefits by hundreds of millions of dollars, the impact of any given decision on transmission requirements (or avoidable transmission requirements) should be rigorously reviewed.

c) If transmission can be justified on the basis of externalities (i.e. benefits not directly experienced by the Company or imparted directly to their customers), are there other decisions (such as coal plant retire/retrofit decisions) that require the examination of external costs and benefits as well?

d) WECC rules and regulations govern reliability requirements for PacifiCorp – including a requirement to avoid circumstances that result in excessive customer outages. The firm rules and engineering studies conducted by WECC and affiliate utilities are a *de facto* internalization of the benefits of reliability – i.e. PacifiCorp is required to obtain and maintain minimum reserve and operating margins, and buffer transmission to avoid outages. Attempting to internalize this cost (as an incremental benefit) in the SBT risks double-counting.

1.11. New link with California ISO shows that flexible resources might have higher value in the future than disclosed in the IRP.

On February 12, 2013, PacifiCorp announced a joint Memorandum of Understanding with the California Independent System Operator (ISO) to create an energy imbalance market – essentially an opportunity to trade in short increment time periods with CA ISO, in return for which the ISO would centrally dispatch PacifiCorp's thermal resources. While the direct benefits (or risks) to PacifiCorp customers are still unclear, the prospect of PacifiCorp sharing resources with California raises a critical resource choice question: is there a higher value placed on flexible dispatchable resources in PacifiCorp once the Company is joined with CA ISO?

California anticipates a huge renewable resource build out over the next two decades, with a large amount of new wind and solar resources expected to be interconnected over the next years. As such, CA ISO is actively deciding how to obtain sufficient amounts of flexible generation that can assist with the integration of large amounts of renewable energy. It is widely expected that flexible resources (i.e. generation that can ramp quickly on demand) will have a very high value to California, while inflexible generation (i.e. baseload units) will have a much lower value.

If PacifiCorp expects to harness monetary value from California's demand for flexible generation, this value should be built into the Company's resource choices. In the same way that the ability to sell pollution credits, RECs, or excess energy that benefits the Company's customers, the ability to sell ancillary services will also benefit the Company's customers – and in California, flexible generation may have distinct value.

1.12. Conclusion

PacifiCorp's 2013 IRP shows measurable improvement in rigor and transparency over its 2011 planning document. However, given that a reasonable set of modeled commodity price parameters indicates massive coal plant retirements, prudent planning requires additional analysis of the risks associated with continued over-reliance on coal-fired generation. Likewise, PacifiCorp must be more forthcoming on the risks its coal units face complying with pollution control regulations. We look forward to the October 3 public meeting with the expectation that PacifiCorp will provide further explanation of the issues described herein.

CERTIFICATE OF SERVICE

I hereby certify that on this 22nd day of August, 2013, I caused to be served the foregoing PRELIMINARY COMMENTS OF SIERRA CLUB upon all party representatives on the official service list for this proceeding. The redacted version of this document was served upon parties via email, and the confidential version of this document was served pursuant to Protective Order No. 13-095 upon all eligible party representatives via USPS.

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Dated this 22nd day of August, 2013 at San Francisco, CA.

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