should allow the Company greater assurance of cost recovery from resource acquisitions, Standard & Poor's states in its May 5, 2005 credit rating report on PacifiCorp that SB 26 "should substantially increase the utility's prospects for cost recovery", the Oregon Commission stated in its February 18, 2004 order it was not persuaded that the new FASB standards would have a negative effect on PacifiCorp, it would be a deterrent to Utah QF development, and states that power purchase obligations is but one of 88 cited factors considered by rating agencies such as Standard and Poor's and Moody's in determining the credit rating for PacifiCorp and utilities.

We are persuaded by UAE's evidence of 88 factors considered by rating agencies in the determination of a utility's credit rating, the potential impact of SB 26 on the Company's credit rating, the Division's reference to the insufficient empirical evidence to support the debt equivalence hypothesis and the unsupportive (of debt adjustments) findings of the studies mentioned on this record, and that it is unclear how individual QF contracts may affect PacifiCorp's credit rating and therefore cost.

F. CONTRACT ISSUES

1. Contract Term

PacifiCorp testifies contracts for the required purchase of power from QFs should be limited to a term of 20 years since the longer the term, the greater the risk to the Company and ratepayers of incurring an uneconomic power purchase agreement; the 20 year term represents an appropriate balance between a term that allows the QF to secure financing and limiting the risks that accompany long range power price forecasting; the QF may continue to sell power to the Company under PURPA requirements after the initial contract term; the contract term does not limit the period in which a QF may recoup its investment, it merely limits the period for which pricing is based on a snapshot projection of avoided costs; and the QF may petition the Commission for an exception to the 20 year contract term limit.

The Division and the Committee testify they support the Company's proposed standard limit of 20 years for a QF contract and allowing the QF to petition the Commission for an exception to the 20 year contract term limit.

UAE testifies the 20 year contract limit for QF penalizes the QF and creates uncertainty as to whether the QF will receive the real levelized capacity payment over the remaining 15 years of a plant with a 35 year life. UAE, US Mag and Wasatch Wind support a standard term of 20 years for QF contracts if the tariff allows QFs to petition the Commission for longer term contracts.

We find reasonable and accept the parties' common position providing for a standard term limit of 20 years for QF contracts with the allowance for parties to petition the Commission for longer terms.

2. Levelization

UAE testifies QF capacity payments for a 20 year contract should be levelized over the 20 year term even if the early years do not include avoided capacity costs and short-term QF capacity payments should be based on a Simple Cycle Combustion Turbine ("SCCT") for shorter term contracts. The Company opposes this adjustment arguing that the avoided front office transactions already address avoided capacity and to add SCCT avoided costs would double count avoided capacity costs.

PacifiCorp, the Division and Committee support levelizing QF capacity payments over the term of a 20 year contract given sufficient security to protect ratepayers in the event of

EXHIBIT A

UTAH HEDGING COLLABORATIVE REPORT

Principles:

1. PacifiCorp has experience in determining the specific price, physical delivery, and operational risk management policies, procedures and strategies (Energy Planning and Procurement) necessary for reliable delivery and price risk management related to natural gas procurement, energy balancing, and hedging.
2. As with other aspects of its business, PacifiCorp's Energy Planning and Procurement activities should be evaluated against a "prudency" standard in general rate cases and energy balancing account (EBA) adjustment cases.
3. These principles and guidelines should be used as a general starting point for prudency analysis, but should not relieve PacifiCorp's burden to demonstrate the prudence of all Energy Planning and Procurement activities.
4. "Value at risk" metrics may provide PacifiCorp with useful risk management information, and can be considered in combination with Fundamental analysis for Energy Planning and Procurement.
5. Energy Planning and Procurement requires constant evaluation, monitoring and updating of all relevant supply, demand, and pricing (Fundamental analysis). The Company should use Fundamental analyses and risk management guidelines in combination with other techniques such as dollar cost averaging to determine timing and volume of hedges. The combined analysis should be used to assist the Company in developing a price view for informed market timing of hedges and opportunistic purchases.
6. Reliability of commodity supplies, delivery risks, and operational issues along with storage and transportation options should be evaluated and may be used as part of the Energy Planning and Procurement plan.
7. Voluntary pre-approval procedures under Utah Code § 54-17-402 may be used for long-term commitments that fall outside of the suggested guidelines.
8. Transparency and regular reporting of PacifiCorp's Energy Planning and Procurement policies, practices and positions are critical to enable regulators and customers to understand and evaluate prudence. Transparency and regular feedback will also help inform all stakeholders of customer risk management tolerances.
9. All commonly used, available and effective physical products and financial instruments may be utilized in Energy Planning and Procurement as appropriate. Costs incurred in prudent Energy Planning (including premiums on options and storage) may be included in the EBA.

General Guidelines:

1. The forecast total requirement for natural gas and electricity should not be fully hedged. A reasonable percentage of the natural gas requirements should remain open to short-term market price exposure and allow for operational flexibility. The percentage of

natural gas requirement that should typically be maintained open to short term market price exposure and for operational flexibility is as follows:

[redacted]

In the event of a conflict, these guidelines take precedence over the Company's value at risk metrics.

2. PacifiCorp should use Fundamental and technical analyses with consideration of the Company's risk management metrics, to determine timing and volume of electricity hedges.
3. Interactions between natural gas and electricity open positions, inclusive of hedges, may be identified and accounted for in analyzing value at risk metrics.
4. Because of relative market illiquidity and potential inaccuracy of forecasted requirements, hedges should normally be limited to 36 forward months, except to the extent Fundamental market analyses, including liquidity, support longer-term purchases and acquisitions.
5. Proposals for long-term natural gas supplies, transportation, storage and price hedges should be solicited and evaluated as part of an Energy Planning and Procurement process, particularly in an environment of favorable Fundamentals. The 36 month guideline for financial hedges and the suggested annual percentage guidelines should not limit opportunities for longer term hedges, supply commitments or storage contracts in a price environment advantageous to natural gas consumers as determined by Fundamentals analyses.
6. Energy Planning and Procurement should be constantly reviewed and updated to reflect current conditions and should include solicitation of stakeholder input.
7. PacifiCorp should prepare a comprehensive Energy Plan at least biannually, and more often upon the occurrence of any significant market event or condition that can reasonably be expected to have a long-term or significant impact on any Fundamental analysis.
8. Reports related to Energy Planning and Procurement should be filed in March and September and should be developed in the context of the EBA tariff. The reports should explain why PacifiCorp executed hedges in the prior six month period with specific volumes, price and timing (and why it did not hedge more volume or different timing), and should include at a minimum:
    a. Current and planned natural gas and electricity requirements, storage and hedged positions
    b. Description of electric transmission and natural gas transportation arrangements as well as existing and emerging related risks
    c. Update on Fundamentals evaluation as described above
    d. Description of deliverability, operational, financial and other risks

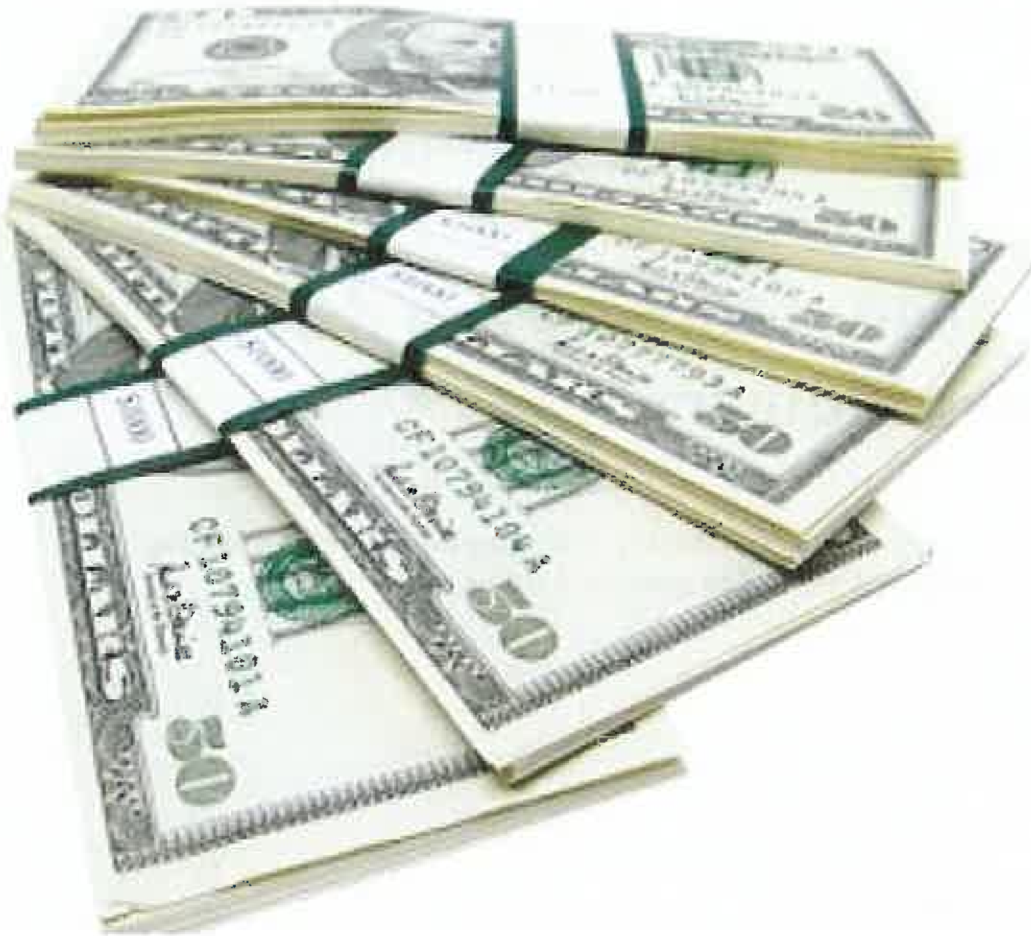
e. Explanation of changes/deviations from Energy Plan and prior filings
f. Summary graphs depicting key internally used value at risk metrics and how they are changing over time
g. Description and explanation of and changes to PacifiCorp's current risk management policies

http://social.csptoday.com/

What yieldco finance can do for the solar industry

Posted on Apr 17, 2015

As the solar industry matures, reducing financing cost is now becoming big news, and not just for PV, but now for CSP as well.



By Susan Kraemer

For years, the big news in solar has been coming out of research and development, from technical innovation. But in what appears to be a sign of the maturing of the industry, this year it seems that the bigger news is coming from the development of new methods of project finance that hold the promise of cutting financing costs.

The biggest of these driving forces in cutting financing costs is the yieldco. Yieldcos are essentially publicly traded holding companies which bundle assets that produce a steady and predictable flow of income, such as energy plants, that have long-term distribution agreements. The cash flow is distributed among investors in the vehicle as dividends.

Perfect for utility-scale solar PPAs

Yieldcos are almost perfectly suited to capturing the value of renewable projects. While they can face many uncertainties during bidding, permitting and development, once they are connected to the grid their cash flows are low-risk, because they typically generate a steady income from 20 or 25-year PPAs or tariffs, once in operation.

Yieldco financing has spread rapidly, with renewable energy giants Abengoa, ACS, NextEra Energy, NRG Energy, and SunEdison all setting up yieldcos to raise millions of dollars through initial public offerings within the last years. Recently, Canadian Solar has followed suit, whereas First Solar and SunPower are on the verge of joining the race to cheap finance.

Among CSP developers, Abengoa has been first out of the gate to use a yieldco to include CSP projects under construction in its yieldco Abengoa Projects Warehouse 1 (APW1), to gain access to what it calls "the cheapest equity" in the market.

The company's yieldco, APW1 will acquire a portfolio of Abengoa projects in Mexico, Brazil and Chile. The total investment by APW1 will be over $2 billion.

YIELDCOS – TWO BIG QUESTIONS

By Angus McCrone
Chief Editor
and
Michael Liebreich
Chairman of the Advisory Board
Bloomberg New Energy Finance

One of the big stories in clean energy in recent times has been the emergence of the "yieldco". In the past 30 months, 15 quoted US and European renewable power ownership vehicles have raised a total of $12bn – one third of new public equity funding for all clean energy companies – and they have jumped to an aggregate market capitalisation of $27.6bn.

The fundamental logic behind the yieldco is strong. In an era of very low interest rates, infrastructure assets can offer stable returns above corporate bonds of a similar term, while bearing relatively low risk. Many asset managers find investing directly in individual projects impossible: they may not have the managerial skills or technical knowledge; they may not be able to hold a large enough portfolio to spread their risk; or they may be prohibited from holding unquoted investments, for instance by pension or insurance legislation.

Yieldcos therefore meet a real need: a quoted portfolio of assets, offering risk diversification and liquidity, with operational management of the constituent projects thrown in.

Clean energy yieldcos were just starting to be talked about before the financial crisis put capital market innovation on hold. Conditions have been friendly for the last few years, and a broad range of investors – moms and pops in the US, wealth managers, pension funds, insurers and even a few hedge funds – have warmed to the proposition they offer.

At the Bloomberg New Energy Finance Summit in New York in April, Jeff McDermott, managing partner of Greentech Capital Advisors, argued that yieldcos had the potential to grow in the same spectacular way that master limited partnerships have done. "I think this will be a $100bn market in the future," he said.

Others, however, have raised important caveats. On the sidelines of the same Summit, Francesco Venturini, chief executive of Enel Green Power, a company that had been rumoured to be thinking of setting up a yieldco, said that he saw yieldcos as nothing more than "financial arbitrage", with very little value creation. "Enel Green Power," he said, "will not be setting up a yieldco".

The truth is that yieldcos face two searching questions if they are to gain a permanent and sizeable place in the armoury of clean energy finance. First, the markets must reach a sensible consensus on how they should be valued. Second, their managers and promoters need to explain how they will work when the current low interest rate environment eventually comes to an end, as it inevitably will.

On the question of valuation, there has been a big difference on the two sides of the Atlantic. In North America yieldcos have been seen as growth stocks, rather than a simple aggregation of projects. Investors' perception has been that, as they build their project portfolio through acquisitions, they pay an escalating stream of dividends per share.

On the European side of the Atlantic, by contrast, yieldcos (or quoted project funds as they are known in the UK) are seen as sedate vehicles for risk-averse investors. They pay a steady yield of 6% or so and their shares trade close to net asset value.

Over-hyped, overvalued and over there?

On the American side, the yieldco pioneer was NRG Yield, which was spun out of US generator NRG Energy in July 2013. It has raised a total of $1.7bn and saw its shares more than double to a peak early this year before slipping to stand 45% up, with a market capitalisation of $3.5bn. It has been joined in the ranks of quoted companies by TransAlta Renewables, Pattern Energy Group, Abengoa Yield, NextEra Energy Partners, TerraForm Power and, most recently, 8Point3 Energy Partners, an asset-owning creation of First Solar and SunPower.

In the European corner, the pioneer was Greencoat UK Wind, an independent fund floated in March 2013 with backing from the UK Department for Business. Greencoat has raised a total of GBP 520m, and is capitalised at $812m at the current sterling-dollar exchange rate. Greencoat shares have risen 13% since IPO. It has since been joined by fellow UK entities Bluefield Solar Income Fund, The Renewables Infrastructure Group, Foresight Solar Fund, John Laing Environmental Assets Group and NextEnergy Solar Fund.

There are also two continental entities with their own characteristics. Capital Stage is a German fund that listed in a very small way in 1998 and has raised substantial additional capital since 2013. Saeta Yield, the subject of a EUR 441m initial public offering in Madrid in February 2015, was born out of Spanish infrastructure company ACS.

The first thing to note is that the North Americans were all formed by spinning a bundle of assets out of large energy companies that develop their own projects. By contrast, the Europeans, with the exceptions of the John Laing fund and Saeta Yield, bought their assets from third parties in competition with other bidders, in some cases also from developers via bilateral agreements.

Generally, the US and Canadian yieldcos pay some 80-90% of cash flow out as dividends – 80% for Pattern, 80-85% for TransAlta, 85% for TerraForm, 80-90% for NRG Yield. Some of the UK funds retain a bigger proportion of their cash flow – Greencoat says it aims to pay out 60%, the John Laing fund says 70%, TRIG cites in its prospectus the equivalent of 77%. There is an exception, Bluefield, which styles itself a "full distribution fund". In Spain, Saeta Yield says it aims to pay out 90% of cash flow.

There is also a difference in funds' appetite for debt with, once again, the UK funds on the conservative side. Foresight Solar, for instance, has no asset-level borrowings, and fund-level leverage is capped at 30% of gross assets. In the US, NRG Yield has debt equivalent to 70% of total assets.

This combination of market perception and financing strategy has led to big differences in share price behaviour. The six North American yieldcos floated in 2013 or 2014 have been on a rollercoaster, with a powerful upswing last year giving way to a 30% average setback in the last few weeks. Despite that, they still remain 34% on average above their IPO prices. By contrast, the six UK funds have seen average gains of just 6%.

The US yieldcos have often traded at large (40% to 100%) premia to book value, while the Europeans have traded at premia of just a few percentage points. Can both valuation approaches be correct?

At heart, a yieldco is just a collection of projects

In thinking about how to value yieldcos, it is vital to understand that they are, at the end of the day, portfolios of projects. Any yieldco valuation has to start with a valuation of its underlying projects, and any premium over that value needs to be carefully justified.

Most wind and solar projects have a life of 20 to 25 years. Revenues over the first 15 or so years are often underpinned by feed-in tariffs, power purchase agreements or long-term green certificate sales arrangements. Revenue variations due to weather conditions are well understood (and can be insured against), and terminal values are generally understood to be negligible.

A yieldco that floats today with a static portfolio of operating-stage assets could pay out all of its cash flows as dividends, and there would be nothing left for investors in two decades' time. Financially, therefore, this simplified yieldco would look similar to a serial bond, by which interest and principal are repaid simultaneously over time, or a fixed-term annuity, and should be valued as such.

What confuses the picture is that over time real-world yieldcos can add to their portfolios, enabling them to increase their dividends and giving the impression of growth. Most have a stated target return for assets they buy, and have been active in the market: a UK quoted project fund might say it pays 7-8% unlevered for a solar park, a US yieldco might say 9% "levered cash-on-cash return".

Yieldcos can fund acquisitions by holding back some proportion of the cash flow from existing projects, or by raising new equity and debt. Either way, it is vital to note that this is not organic growth, it is acquired growth. It should only serve to increase the value of the yieldco if the projects are acquired below their market value, or if the yieldco can generate some sort of extra value in the portfolio.

Added value, but how much?

Yieldcos may provide some extra sources of added value, over and above the financial arbitrage described above, which could justify a premium over their underlying asset value:

- They may have long-term options to buy projects from former parent companies, dubbed right of first offer (ROFO). These agreements, which are particularly common among US yieldcos, mean that the yieldco has access to an assured pipeline of projects.

- Management may be able to add some value to the portfolio that was not present when projects were acquired, for instance by arranging lower-cost debt, bulk-buying operation and maintenance services, or improving the prices achieved for power or green certificate sales.
- Revenues may offer an element of inflation protection, on top of the static yield on each asset. In some jurisdictions feed-in tariffs, PPAs or green certificate prices are adjusted for inflation over time.
- There may be some terminal value to be realised, although this possibility has yet to be tested, as a result repowering – replacing the original equipment with more powerful or efficient models – retrofitting improved components, or negotiating with landowners an extension to the project life or through land sales.

While each of these factors might justify some level of premium over the value of the underlying projects, the question is how much? Taken together, could they justify a 20% premium? A 40% premium?

A look at the list of holders of yieldco shares does provides some grounds for caution. Soaring valuations have attracted investment from hedge funds, which are likely to have return expectations higher than the yields available from the underlying clean energy projects held by the yieldco, even on a levered basis.

It's all about risk

Recent events have suggested the market is taking a closer look at the risk of investing in yieldcos. Existing yieldcos have succeeded in raising new money (TerraForm raising $688m in June being just the largest issue), and 8Point3 Energy completed a $420m IPO, also last month. There are also some new IPOs being marketed – including a second TerraForm yieldco, this time concentrating on assets in emerging markets, and a second NextEnergy vehicle, aimed at solar in Spain and Italy.

However, two other attempts to float continental European asset-owning vehicles have hit turbulence, with Solairedirect of France postponing its $242m IPO in April because of insufficient interest and Chorus Clean Energy of Germany putting its $142m IPO on ice this month, blaming "the sharpened economic situation in Greece and the impact on global financial markets".

Investors have also received a reminder that these entities can be exposed to regulatory risk. On July 8, UK Chancellor George Osborne surprised the renewable energy sector in his country by removing the exemption of renewable electricity from the country's Climate Change Levy. Our BNEF colleagues estimate that this move will reduce revenues for existing wind and solar projects by about 2% over the next 20 years. The move was unexpected and led to next-day falls of 3% or more in the share prices of UK quoted funds such as Greencoat, TRIG and Foresight Solar.

Shifts in regulation and policy support are, of course, not the only hazard that yieldcos face. Electricity price risk is an important one, whether it relates to the period after the expiry of a power purchase agreement or that part of revenues not covered by a green certificate or feed-in tariff.

In all, US yieldco TerraForm Power lists no fewer than 27 pages of "risk factors" in its 2014 annual report, ranging from the mundane "wind plants located in Maine have experienced curtailment issues which may adversely affect revenues" to the zoological "harming of protected species can result in curtailment of wind project operations".

Biggest risk of all

However, perhaps the biggest risk of all inhabits just a single paragraph on page 48 of the TerraForm report. It states: "Market interest rates may have an effect on the value of our class A common stock".

Investors' enthusiasm for yieldcos has been driven partly by their increasing confidence in wind and solar projects as an asset class to compare to traditional infrastructure such as roads and hospitals. But it has also reflected the hunger of pension funds, insurance companies and wealth managers for dividend income at a time of record-low interest rates.

A yieldco paying 6%, or even 5%, with the chance of that rising over time, has a relatively low bar to overcome in investors' minds when US 10-year government bond yields are at 2.4%, those in Germany at 0.9% and in the UK, 2%. That bar, however, would look much more daunting if US 10-year rates return to 5.25% as they were in 2007, or even to 4% as they were in early 2010.

If that happens, the market would expect yieldcos also to offer higher yields than they do now. That does not mean the model ceases to function, as the underlying sources of value it provides would still be there. As Mike Garland, chief executive of Pattern Energy, said at the BNEF Summit in April, if interest rates go up, his yieldco

UBS

Global Research

May, 2015

Examining the YieldCo Maturation

Reaching Adolescence

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This report has been prepared by UBS Securities LLC.

Cash Yield or Cash Return

Return metrics are increasingly blurred

- Cash is typically front end loaded
  - How much paying in valuation for *existing* vs. *prospective* growth

- Overall return profile
  - Tends to be in the ~7% unlevered returns
  - Which typically translates to ~9% levered returns, but *higher* cash yields

- Contract tenor
  - Varies between 10-20 years
  - The real question is how much of a *cliff* exists in the contracts

    Biggest risk is high-priced California PPAs rolling off… into lower market
  - Difference between subsidized reneweables and at-market MLPs. Volume Risk vs. Contract Risk.

UBS

What a YieldCo is Not!

We suspect significant continued confusion over several aspects

- It's not really about Yield, but Growth
  - *Should be called GrowthCo's!*
- It's not a 'Retail' Product
  - This is not marketed to retail, nor is it a 'low-risk' product
  - Capital markets execution risk is quite real – and the biggest focus
- Has significant contract expiration risk
  - Threat of asset quality risk in future deals remains the risk for sector
  - Pressure on management to continue to deliver deals, but sacrificing?
  - Quantity and Tenor of Bullet Maturity debt at HoldCo is a further risk
- Is not a low risk proposition
  - Has real capital markets execution risk

A Deeper Look into Yieldco Structuring

Submitted by Anonymous on Wed, 09/03/2014 - 1:29pm

By: Marley Urdanick

Yieldcos seem to be the renewable energy financing mechanism in vogue lately. As the newest 2014 headliners, TerraForm Power and NextEra Energy attract media attention, and NRG Yield continues to exceed expectations, many industry stakeholders are asking: what is a yieldco and why is it attractive from an investment and finance perspective? To answer these questions, this article summarizes key elements of the yieldco structure and provides an overview of the current U.S. market.

The Basics

A yieldco is a dividend growth-oriented public company, created by a parent company (e.g., SunEdison), that bundles renewable and/or conventional long-term contracted operating assets in order to generate predictable cash flows. Yieldcos allocate cash available for distribution (CAFD) each year or quarter to shareholders in the form of dividends. This investment can be attractive to shareholders because they can expect low-risk returns (or yields) that are projected to increase over time. The capital raised can be used to pay off expensive debt or finance new projects at rates lower than those available through tax equity finance, which can exceed 8%.

The case for yieldcos can be compelling, especially as an alternative to master limited partnerships (MLPs) and real estate investment trusts (REITs). Yieldcos, sometimes referred to as "synthetic MLPs," are structured to simulate the avoided double-taxation benefit of MLPs and REITs. This means that rather than taxation taking place twice (once at the corporate level and again at the shareholder level), the yieldco is able to pass its untaxed earnings through to investors [1]. This is achieved by matching strong positive cash flows (income from assets) with losses that exceed taxable income (losses due to renewable asset depreciation and expenses). These "net operating losses" reduce the company's taxable income so that the company is taxed on lower annual earnings, or may not even owe taxes at all. Net operating losses can "carry forward" for future taxable events and therefore, many yieldcos do not expect to pay significant income tax for a period of years. Additionally, dividends may also receive favorable tax treatment at the shareholder level if the returns are treated as return *of* the original investment, as opposed to return *on* investment. When earnings are taxed at only one level, the company is able to raise capital from shareholders more affordably [2]. Class A Common Stock shareholders typically receive a 1099-DIV form for tax purposes, rather than the K-1 form associated with MLPs. This is good news for many investors accustomed to the K-1, which can be cumbersome across multiple states and have limitations on utilization in a tax return [3].

Below is a general representation of the yieldco organizational structure, adapted from NRG Yield. The parent company must own a majority share of the yieldco (Class B Common Stock), while public shareholders are entitled to a minority share (Class A Common Stock). The revenue generated from projects owned and/or operated by "operating subsidiaries" is passed through this structure to deliver returns to shareholders.

JUL 17, 2013

1 COMMENT

A Rock that Churns out Cash: Solar YieldCos

AUTHORS
Roy Torbert Manager
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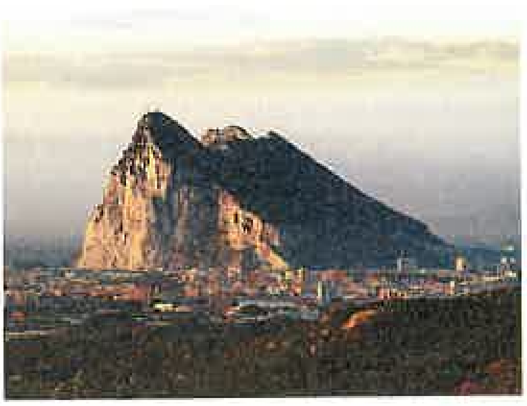

Own a piece of the rock. For years the slogan served Prudential Financial, whose logo is a rendering of the Rock of Gibraltar. The implications were clear—if you want investments that are solid and reliable, go with Prudential.

Not to take anything away from Prudential, but there's a new "rock" in town: solar. We're talking photovoltaics (i.e., slabs of, most often, silicon rock), which have been called, "a rock that makes electricity." Think about it: no moving parts, no fuel, with 20-years-or-more of contract-able electricity production. Like inventor and marketing personality Ron Popeil's famous rotisserie, you basically "set it and forget it." In other words, solar PV is a rock ... that produces electricity. (Granted, it does so with some minor, yet caring and intelligent, O&M over the years.)

And now, with the July 16th initial public offering (IPO) of NRG Yield (NYSE: NYLD) it looks like solar can now take a page out of Prudential's playbook and be a rock that can also provide you, as the individual investor, steady and solid yields.

NRG Energy, the largest independent power producer in the nation, created NRG Yield, Inc., a subsidiary that owns, operates, and acquires renewable and conventional electricity generation projects, primarily solar, wind, and natural gas. NRG Yield's initial profile is an aggregation of eleven renewable and conventional utility-scale (i.e., big) power plants and two distributed solar project portfolios (think lots of solar PV projects on commercial building rooftops). The NRG Yield public offering will let NRG sell off a portion of its ownership of these power-generating assets to the new NRG Yield shareholders, thereby raising additional capital to fund more solar.

SOLAR FINANCING STILL TOO PRICEY

Substantial decreases in the cost of solar panels as well as the advancement of third-party financing has made solar pricing—paid as a financed monthly bill instead of tens of thousands of dollars upfront—more affordable than utility rates for hundreds of thousands of customers. While third-party financing has opened up the solar market, it has limits to its own growth. Solar panels might be cheap, and financing attractive for some individual residential customers (when compared to utility rates), but larger-scale financing for distributed solar projects is expensive, largely due to two major costs:

- high cost of capital, comparable to credit card lending rates
- very high upfront financial transactional costs

Bringing down costs in both categories by applying cheaper money (capital with lower required rates of return) and more standardized, mainstream financing vehicles that have lower transactional costs, is critical for moving the economic viability of solar from *some* customers to *most* customers.

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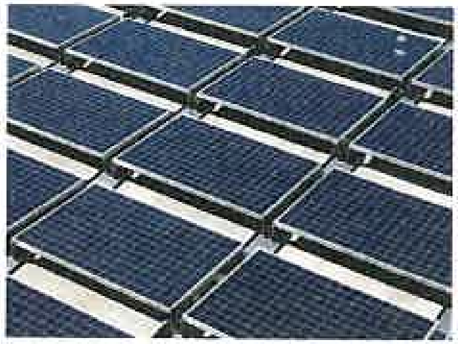
THE ROLE OF YIELDCOS



Over the past year, momentum has been growing for the use of master limited partnerships (MLPs) or real estate investment trusts (REITs) to fund renewable energy and encourage institutional investors to consider solar. Both MLPs and REITs are yield-oriented investments, where a high percent of earnings are passed to shareholders (called "unit holders" for an MLP). But some of the interest in MLPs and REITs has waned as industry pundits have espoused the trickiness of using these entity types while capturing tax benefits, which is a big part of financing solar these days. They also face governmental hurdles (MLPs require legislation while REITs require IRS rule clarifications or new legislation).

But MLPs and REITs aren't the only games in town. Another type of yield-producing entity, the "YieldCo," lets solar developers shift their renewable generation to a pure-play dividend-oriented company that's not bound by the investment and income rules of MLPs or REITs and needs no new governmental actions. Sometimes the term "YieldCo" is used as a catch-all for these yield-oriented investments, and sometimes YieldCos are specifically meant to be only "C" corporations designed to pass through dividends.

A "C" corp. solar YieldCo can take tax benefits if it has a tax bill, and likely NRG Yield will do so by balancing its liability-heavier fossil-based assets with its benefits-heavier renewable assets. That mix might be tougher for YieldCos focused entirely on solar, so more financial engineering might be needed to bring them forth. Solar pure-play YieldCos will likely find it a bit easier when solar tax benefits get smaller in 2017 with the investment tax credit decrease from 30 percent to 10 percent. In addition, there might be an opportunity to mix older solar assets that've aged past their tax benefit period and now have tax liabilities with newer solar assets which have significant tax benefits.

ARE YIELDCO STOCKS AN INTERESTING BUY?

Similar to how the exciting promise of solar securitization mixes with the discomfort of securities' mental association with real estate securities and their contribution to the 2008 financial crisis, YieldCos are not without some concerns. For example, while YieldCo losses should be public with normal SEC reporting rules, you have to look at the prospectus to see if you're getting a fair shake between the YieldCo's management (in this case NRG) and you the potential shareholder. However, YieldCos formed from reliable, long-term, power-generating assets that have signed agreements with well-mixed, high-credit buyers (e.g., utilities) should be reasonably safe bets.

This YieldCo model enables individual and institutional investors pure-play access power generation cash flows, not possible when buying stock in solar developers (e.g., SolarCity) or vertically integrated solar companies (e.g., First Solar), where there is more to those businesses than cash flows from operating solar projects. Granted, crowdsourced funding also provides focused investment on solar asset cash flows, and we at RMI find this crowdsourcing compelling. In the near term, however, crowdfunding is unlikely to provide the scale of solar financing available through NRG Yield and follow-on YieldCos.

NRG YIELD'S SPECIFICS

In total about 29 percent of NRG Yield's generation is renewable (wind and solar). So indeed, NRG Yield is not a solar-only investment, and indeed is a notable contrast to Mosaic's crowdsourced platform which *does* offer pure-play solar cash-flow-based returns. However, NRG Yield intends to use the proceeds from the IPO to fully fund the remaining 123 MW of the 250-MW California Valley Solar Ranch project.

The price for NRG Yield and its 1,324 MW of initial capacity sold for $431 million, a bit over announced expectations of $410 million. Industry experts expect dividend returns in the range of 5–7 percent, paid annually to shareholders. That's quite an improvement over the 8–15 percent cost of capital that generally sits behind distributed solar financing.

YIELDCOS AN IMPORTANT FINANCING TOOL FOR SOLAR'S ECONOMIC COMPETITIVENESS

YieldCos are designed to provide stable, long-term cash flows, similar to annuities, and be as easy as buying stocks or bonds. This means folks like you and us can buy in, which is a lot different than the normal private cabal of solar finance consisting of venture capital, private equity, and tax equity from big banks and insurance companies. Long-term contracted solar, insulated from commodity prices, is a great offering for yield-oriented investors and we think demand exists for much more. YieldCos also make solar cheaper in cents per kWh (the levelized cost of ownership), because the financing cost of capital is lower. In short, they're likely a scalable and dependable (like a rock) solution of which we're hoping to see more.

Like 23 Tweet 32

TAGS: ELECTRICITY | SOLAR | SOLAR FINANCE | YIELDCOS

RECOMMENDED READING

- Yahoo's Pursuit of Green Power: New Business Models Offer Companies High-Impact, Economic Alternatives
- Report Release: Renewable Microgrids
- The Renewable Energy Market is Evolving. Here's How.

SHOWING 1-1 OF 1 COMMENTS

August 14, 2013

The yield will reach 4.25 percent by the end of next year, according to Bloomberg projections (NYLD:US) based on company filings.

(http://www.businessweek.com/news/2013-08-02/ipo-boom-in-renewables-as-dividend-yield-beat-gilts-u-dot-k-dot-credit)

Thad Curtz

PAGE: 1

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Via Electronic Mail and UPS

July 13, 2015

Executive Director and Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
1300 S. Evergreen Park Drive, S.W.
Olympia, Washington 98504-7250.

Re: Washington Utilities and Transportation Commission v. PacifiCorp, dba Pacific Power & Light Co.
Docket No. UE-144160

Dear Mr. King:

Please find one copy of the Declaration of John Lowe in the above captioned docket. Pursuant to the Prehearing Conference Order, electronic copies of the Declaration will be filed with the records center and served upon the parties. Electronic copies of the Declaration will be provided in Word and pdf format, and the Attachment will be provided in pdf format only.

Sincerely,

Irion A. Sanger

cc: Service List (via email)

PENGAD 800-631-6989
EXHIBIT
1
REC
262985

CERTIFICATE OF SERVICE

I hereby certify that I have caused to be served the following DECLARATION OF JOHN LOWE in WUTC Docket No. UE-144160 by electronic mail to the parties on the attached service list.

DATED July 13, 2015

Irion A. Sanger

Status	Name and Address	Phone & Fax	Added	By
Applicant	Dalley, Bryce Vice President Pacific Power & Light Company 825 NE Multnomah STE 2000 Portland, OR 97232 washingtondockets@pacificorp.com	Tel: (503) 813-6048 Fax: (503) 813-6060	2/11/2015	Snyder, Jennifer
Applicant's Counsel or Representative	Till, Dustin Senior Counsel Pacific Power & Light Company 825 NE Multnomah St. STE 1800 Portland, OR 97232 Dustin.Till@pacificorp.com	Tel: (503) 813-6589 Fax: (503) 813-7252	2/11/2015	Snyder, Jennifer
Assistant Attorney General	Casey, Christopher M. Assistant Attorney General WUTC 1400 S. Evergreen Park Drive SW,	Tel: (360)664-1189	2/17/2015	Targus, Lorri

	PO Box 40128 Olympia, WA 98504-7250 ccasey@utc.wa.gov			
Intervenor Representing: Renewable Energy Coalition	Lowe, John Renewable Energy Coalition 12050 SW Tremont Street Portland, OR 97225 jravensesanmarcos@yahoo.com		3/17/2015	Targus, Lorri
Intervenor's Counsel or Representative Representing: Boise White Paper	Pepple, Tyler Davison Van Cleve, PC 333 SW Taylor STE 400 Portland, OR 97204 tcp@dvclaw.com	Tel: (503) 241- 7242 Fax: (503) 241- 8160	4/23/2015	Snyder, Jennifer

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY, Respondent.	)))))))))))	**DOCKET NO. UE-144160** **DECLARATION OF JOHN R. LOWE**

John R. Lowe declares:

1. My name is John R. Lowe. I am the Executive Director of the Renewable Energy Coalition ("REC"). My business address is 12050 SW Tremont Street, Portland, Oregon 97225.

2. I am over the age of twenty-one, have personal knowledge of the facts set forth herein, and am competent to testify to those facts.

3. The purpose of this declaration is to oppose Pacific Power & Light Company's ("PacifiCorp")[1] Schedule 37 avoided cost update that was filed in this proceeding on December 29, 2014. REC recommends that the Washington Utilities and Transportation Commission (the "Commission") retain Schedule 37's current rate design with a monthly kilowatt ("kW") capacity payment, and a megawatt hour ("MWh") energy charge. REC also recommends that the Commission increase the monthly kW

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[1] This declaration refers to Pacific Power & Light Co. as PacifiCorp for the sake of convenience because I discuss both the company's Washington operations (which are under the name Pacific Power & Light Co.), and the company's other operations (which are under the name PacifiCorp, or sometimes Rocky Mountain Power).

capacity payment, and/or MWh energy charge because they under compensate Washington qualifying facilities ("QF") for the capacity and energy they provide to PacifiCorp.

Background

4. REC was established in 2009, and is comprised of over thirty members who own and operate nearly forty non-intermittent QFs in Oregon, Idaho, Washington, Utah, and Wyoming. REC's members have power purchase agreements with Northwest utilities, including PacifiCorp. Yakima-Tieton Irrigation District has been a Coalition member since 2011, and sells its power to PacifiCorp from two about 1.5 MW hydroelectric projects (the Orchard and Cowiche projects). These facilities have been operating since 1986, and have been a consistent reliable source of generation even in drought years due to their senior water rights. As an irrigation district, the power sales for these facilities are reinvested into the community, and providing significant benefits to the local economy.

5. REC actively participates in utility rate proceedings and investigations in the Northwest regarding power purchase agreement terms and conditions including avoided cost prices, integrated resource planning, interconnection, and other matters relevant to QFs and independent power producers. REC also monitors and lobbies legislatures on energy policy matters. In addition, REC provides consulting services to individual members on contractual, operational, interconnection, and other issues related to their electric generation facilities and the interface with the purchasing utility.

6. PacifiCorp has 141 existing QFs representing 1,732 MW of installed capacity in all six of its state jurisdictions.

7. In contrast, PacifiCorp currently has only three Washington QFs selling power to the company. These are the Yakima-Tieton Irrigation District's Orchard and Cowiche projects, and Deruyter Dairy's 1.2 MW methane facility. The Deruyter Dairy methane facility is the only Washington QF that has been built in and currently selling power to PacifiCorp since 1990. To my knowledge, the only other QF to have sold to PacifiCorp since 1990 in Washington was the City of Walla Walla. The City has since decided to terminate sales to PacifiCorp after the original purchase power agreement expired and the prices dramatically dropped in accordance with recent Schedule 37 prices. The total MWs of all three operating projects selling power to PacifiCorp in Washington is about 4 MWs, which represents less than 0.3% of all PacifiCorp's MWs of QF contracts.

8. In its other states, PacifiCorp has 816 MW of newly executed wind and solar qualifying facility power purchase agreements from 36 projects having in-service dates by the end of 2016. PacifiCorp 2015 Integrated Resource Plan ("IRP") at 4. As of March 2015, PacifiCorp had about 89 requests for new QF contracts in its other states, all but two of which are wind and solar.

9. In my experience based upon 35-years plus of implementing the Public Utility Regulatory Policies Act ("PURPA") in the Northwest, it is highly unlikely that all requests for new contracts or even all QFs that sign contracts with the utility will result in a constructed QF that sells electricity to the utility. In other words, many QFs request contracts or enter into contracts, but are unable to complete financing and construction of their facility. Regardless, the requests for contracts and the number of new contracts in PacifiCorp's non-Washington service territory are significant.

10. PacifiCorp has zero newly executed QF power purchase agreements in Washington. PacifiCorp has no interconnection or power purchase agreement requests from any QFs in Washington. It is significant that there are no requests for contracts or new contracts in Washington, especially given the requests and new contracts in other states.

11. The numbers of PacifiCorp's Washington QFs and MWs has been and continues to be significantly lower than PacifiCorp's other states. This indicates that PacifiCorp's Washington implementation of the Public Utility Regulatory Policies Act has not been, and is currently not, favorable to the development of QFs. Favorable contract terms, including length of contract and prices, are necessary to encourage the development of QFs. Washington has a number of significant untapped renewable energy resources that could be developed to benefit utility customers and the local economy with proper implementation of PURPA. The need for expansion of the Washington renewable portfolio standard, compliance with the Environmental Protection Agencies ("EPA") Section 111(d) rules or other regulator requirements could also be reduced with the development and retention of cost effective QFs.

PacifiCorp Schedule 37

12. PacifiCorp purchases power from QFs two MWs or smaller in Washington pursuant to its Schedule 37 Cogeneration and Small Power Production rate schedule. QFs above 2 MWs must negotiate contracts with PacifiCorp. No QFs larger than 2 MWs have been built in Washington and sold their power to PacifiCorp. All of PacifiCorp's other states have larger QFs, and every state but Washington has at least one QF 20 MWs or larger. Even the recently built 15 MW Tieton Dam project in

PacifiCorp's service territory northwest of Yakima had to sell its output out of state. The fact that PacifiCorp's avoided cost rates and contract terms were less favorable than transmitting the power out of state is illustrative of the problems facing local energy developers in PacifiCorp's Washington service territory.

13. Avoided cost rates under Schedule 37 include capacity and energy payments. The capacity payment is based on a fixed dollar per kW month rate. Under the currently effective Schedule 37, the fixed dollar per kW month capacity rates for the five-year period of 2015-2019 start at $2.49 and rise to $2.66. The energy payment is a fixed dollar per MW hour rate. Under the currently effective Schedule 37, the fixed dollar per MW hour energy rates for the five-year period of 2015-2019 start at $31.92 and rise to $40.22.

14. Fixed energy and capacity rates are only available to QFs for the first five years of any contract.

15. PacifiCorp's avoided cost rates in Schedule 37 are significantly lower than the avoided cost rates for Puget Sound Energy ("PSE") and Avista. Also, PacifiCorp files Schedule 37 in all other states except California, and the rates and/or terms are more favorable in all of those states compared to Washington. This indicates that PacifiCorp's avoided cost rates and/or terms need improvement rather than further degradation in the form of eliminating capacity payments

PacifiCorp's Proposed Revision to Schedule 37 Avoided Cost Rates

16. PacifiCorp has proposed to eliminate the dollar per kW month capacity rate.

17. PacifiCorp supports its proposal because its 2013 integrated resource plan ("IRP") Update indicates that its next major thermal resource will be acquired in 2027. PacifiCorp claims that QFs will not cause the company to avoid capacity costs because the company may not need to acquire a new thermal resource until 2027.

18. Prior to 2027, PacifiCorp has a significant energy and capacity resource need. In this proceeding, PacifiCorp states that it will rely upon market purchases, or front office transactions for both its energy and capacity needs. PacifiCorp proposes that Schedule 37 only include the company's estimates of the market purchase prices. The value of these market purchases would be estimated using PacifiCorp's Generation and Regulation Initiative Decision computer model.

19. PacifiCorp has proposed an alternative rate design. PacifiCorp proposes to differentiate the fixed dollar per MWh energy rate into a heavy load hour and a light load hour rate. This does not change the effective value of sales from consistent 24-7 producer like Yakima-Tieton's irrigation system hydro projects, but could change the compensation paid to wind and solar projects.

Renewable Energy Coalition Proposed Schedule 37 Avoided Cost Rates

20. REC recommends that the kW month capacity rate should at a minimum be retained because QFs are providing the company with capacity. REC further recommends that the: 1) the dollar per kW month capacity rate be increased to better reflect the capacity resources the company plans to acquire; and/or 2) the dollar per kWh energy rate be increased because it does not accurately reflect expected energy costs.

A. The Commission Should Retain a kW Month Capacity Rate

21. PacifiCorp needs both energy and capacity that can be avoided by QF purchases. In its 2015 IRP, PacifiCorp plans to meet its energy and capacity needs over its twenty-year planning horizon with short-term market purchases, demand side management, coal plant conversions, and almost 3,000 MWs of new natural gas facilities. PacifiCorp is also planning on significant investments in its existing coal fleet to maintain its existing energy and capacity resources that will be made before the acquisition of its next thermal resource. QFs that sell power to PacifiCorp will help the company avoid its need for these energy and capacity resources, including coal plant investments and new gas generation facilities.

22. PacifiCorp's IRP plans on acquiring a new combined cycle combustion turbine in 2027 or 2028 (2013 IRP Update and 2015 IRP). PacifiCorp's planned resource acquisitions have historically been inaccurate, especially during the longer-term. For example, in 2008 PacifiCorp did not "plan" on acquiring a new thermal resource until 2012. However, PacifiCorp acquired the 520 MW Chehalis plant in 2008. PacifiCorp's resource needs identified in its current IRPs may be even more inaccurate. PacifiCorp's actual resource acquisitions could significant change if its IRP assumptions prove inaccurate, including but not limited to: 1) changes in Washington's RPS; 2) PacifiCorp joining the California Independent System Operator; 3) the adoption of a federal RPS; 4) adoption of a state or federal carbon tax; 5) the adoption of EPA's Section 111(d) rules; 6) closure of part or all of the Colstrip or other coal generation facilities; 7) the inability to capture the high levels of demand side management; and 8) the lack of availability of power in the wholesale market. All of these policies could result in a reduction in coal

generation, and an increase in renewables, baseload gas, and peaking gas generation well before 2027.

23. In the past, PacifiCorp's IRPs planned to acquire a new thermal resource in about four or five years. As each subsequent IRP was released, the four to five year time period remained constant, but the actual date for the company's planned thermal resource acquisition moved further out in time. For example, in 2005 the next planned thermal resource acquisition was 2010, in 2007 the planned next thermal resource acquisition was 2012, in 2009 the next planned thermal resource acquisition was 2014, etc.

24. The next planned thermal resource acquisition in PacifiCorp's most recent IRPs is now much longer than five years. Specifically, PacifiCorp claims that it will not build a new thermal resource until 2028, which is in 12 or 13 years. Under PacifiCorp's approach, this will result in much longer and historically unprecedented "sufficiency" periods.

25. PacifiCorp's proposal to not make capacity payments until the acquisition of a planned thermal resource acquisition could mean that there will always be a period of resource "sufficiency" and no capacity payments. If the resource sufficiency period is short and the contract term length is limited to five years, projects will receive no or only a year or two of capacity payments. With longer sufficiency periods, as is the case now, projects will no longer receive capacity payments. This means that existing Washington projects that have always received capacity payments will no longer be paid for the capacity they provide to PacifiCorp.

26. Under PacifiCorp's proposal, Washington QFs will not be paid for capacity if they enter into a contract when the next thermal resource acquisition is in six years (2021) or longer. For example, assume that PacifiCorp is planning its next thermal resource acquisition in six years (2021). Under PacifiCorp's proposal, a QF that enters into a new five-year contract in 2015 will not be paid for capacity during the entire contract term. In 2021, PacifiCorp will have a new IRP, which will likely not be planning on a new thermal resource for more than five years, and its new Schedule 37 will not have any capacity payments. If the QF renews its contract and enters into a new five-year contract in 2021, then the QF will again not be paid for capacity. The QF will have caused PacifiCorp to reduce both its energy and capacity needs (including the capacity related to the next planned thermal resource), however, the QF will not be paid for capacity under the company's approach.

27. All QFs provide capacity during all years, including the years before the next acquisition of a new thermal resource. For example, QFs can reduce PacifiCorp's need to re-invest in its coal fleet. In addition, PacifiCorp plans on QFs as capacity resources. In its 2015 IRP, PacifiCorp is planning on the availability of 255 MWs of QFs to meet its system peak. PacifiCorp 2015 IRP at 62. These QFs have been causing, and those that renew their contracts will continue to cause, PacifiCorp to avoid capacity costs.

28. It is particularly inappropriate to not pay QFs that PacifiCorp plans on entering into follow-on contract extensions a full capacity payment. A QF that is seeking renewal and/or extension of its contract should receive a capacity payment because the capacity that it provides has already been included in the utility's IRP load resource balance. In other words, PacifiCorp's IRP assumes these QFs renew their contracts.

Without including these QFs in its resource plans, the company would have would need to acquire new capacity and energy resources.

B PacifiCorp's Current Schedule 37 Fails to Fully Compensate QFs

29. PacifiCorp's avoided cost rates under compensate QFs because they do not fully account for the potential availability of market purchases. Over the twenty-year planning period, PacifiCorp's 2015 IRP assumes that it will be able to purchase between 727 and 1,411 MWs from the market, or front office transactions. My understanding is that PacifiCorp has not conducted an analysis in its IRP to determine if there will be sufficient market liquidity to enter into these market purchases. The Northwest Power Planning and Conservation Council has estimated an overall Northwest market shortfall, and PSE's current IRP is studying the impact of a market shortfall on its operations. The acquisition of electricity from QFs would reduce the need for PacifiCorp to rely upon an uncertain wholesale market. I do not have a specific adjustment to PacifiCorp's Schedule 37 to compensate for the potential market illiquidity; however, this supports increasing the PacifiCorp's avoided cost rates to reduce this risk. The Commission could also direct PacifiCorp to develop an adder to the energy or capacity rate to account for the risk reduction associated with QFs.

30. PacifiCorp's kW per month capacity rate under compensates QFs for capacity because its past approach was based on the fixed costs of simple cycle combustion turbine ("SCCT") for only three months out of year. This means that only one fourth of the fixed costs of a SCCT have been used to calculate the capacity payment. If PacifiCorp acquires a SCCT peaking resource, then it will incur its fixed costs for all twelve months out of the year. In other words, PacifiCorp is unlikely to acquire a SCCT

for only those months for which it has peak capacity need. Therefore, it is more appropriate to include the full costs of a SCCT in the capacity payment for QFs.

31. PacifiCorp's avoided cost rates also under compensate QFs because they do not account for the costs associated with the company's significant planned investments in environmental upgrades to retain its existing coal facilities. These are actual and planned investments that are not included in the company's current Schedule 37 avoided cost rates. Without these upgrades, PacifiCorp would have to secure a large amount of new capacity and energy resources, thereby significantly reducing its period of resource sufficiency. PacifiCorp has identified a number of environmental upgrades at its existing coal facilities in its 2015 IRP that it plans to make before the acquisition of its next thermal resource, including:

- Hayden 1 SCR by Jun 2015
- Jim Bridger 3 SCR by Dec 2015
- Hayden 2 SCR by Jun 2016
- Jim Bridger 4 SCR by Dec 2016
- Craig 2 SCR by Jan 2018
- Naughton 3 Conversion by Jun 2018
- Craig 1 SCR by Aug 2021
- Hunter 1 SCR by Dec 2021
- Jim Bridger 2 SCR by Dec 2021
- Jim Bridger 1 SCR by Dec 2022
- Colstrip 4 SCR by Dec 2022
- Huntington 1 SCR by Dec 2022
- Colstrip 3 SCR by Dec 2023
- Hunter 3 SCR by Dec 2024
- Cholla 4 Conversion by Jun 2025

2015 IRP, Vol. II at 298-299.

32. Similarly, PacifiCorp's proposed extraordinarily long sufficiency period is sending a price signal to prospective QFs that the long-term value of their capacity is worth very little. At the same time, the Company is facing the challenge of compliance

with EPA's proposed Section 111(d) rules and other greenhouse gas regulations, which propose significant reductions in carbon emissions. The proposed rules are creating significant uncertainty with respect to the Company's long-term resource plan. An important policy question that the Commission should consider is whether it is wise to be signaling to QFs, particularly renewable QFs, that their capacity is of little long-term value, and consequently discouraging their development, at this critical time of changing environmental regulations.

33. In an Oregon Public Utility Commission ("OPUC") investigation into PURPA and QF policies Docket No. UM 1610, the Renewable Energy Coalition and other QF parties have sponsored the testimony of expert witness Kevin Higgins of Energy Strategies. Mr. Higgins estimated the capacity value of only the first six listed environmental upgrades, which resulted in a capacity value of $47.11 per kW-year. I have attached Mr. Higgins testimony from the OPUC proceeding, which explains how the capacity value with these environmental upgrades was calculated. It would be appropriate to include these capacity costs in PacifiCorp's Schedule 37 rates.

Conclusion

34. PacifiCorp's current Schedule 37 does not fully compensate QFs for the capacity and energy they provide to the company. This is illustrated by the extremely low level of existing QFs and the lack of any interest in QF development in PacifiCorp's Washington service territory.

35. At a minimum, the Commission should retain the current kilowatt month capacity payment in PacifiCorp's Schedule 37. I recommend, however, that the Commission increase the current kW capacity payment. Options to increase the capacity

payment are: 1) including the entire annual fixed costs of a SCCT rather than only three months; and 2) including the costs of PacifiCorp's planned environmental upgrades at its existing coal facilities. The Commission could direct PacifiCorp to make other changes, including a market risk adder to reflect the potential market illiquidity associated with relying upon short-term market purchases.

36. If the Commission does not retain or increase the current kW month capacity payment for all QFs, then REC recommends that the Commission consider other solutions to more accurately compensate QFs. These could include maintaining the capacity payment for already operating QFs that PacifiCorp is relying upon in its IRP, and increasing the contract term for all QFs.

I declare that under the laws of the State of Washington that the foregoing is true and correct. Signed at Portland, Oregon on July 12, 2015.

John R. Lowe

ATTACHMENT A

Kevin Higgins Testimony
Docket No. UM 1610

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UM 1610

Phase II

In the Matter of

PUBLIC UTILITY COMMISSION OF OREGON

Investigation into Qualifying Facility Contracting and Pricing.

OPENING TESTIMONY OF

KEVIN C. HIGGINS

ON BEHALF OF

RENEWABLE ENERGY COALITION ("REC"),

COMMUNITY RENEWABLE ENERGY ASSOCIATION ("CREA"),

ONEENERGY and

OBSIDIAN RENEWABLES, LLC

REDACTED

MAY 22, 2015

OPENING TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal with Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by the Renewable Energy Coalition ("REC"), the Community Renewable Energy Association ("CREA"), OneEnergy, and Obsidian Renewables, LLC ("Joint QF Parties").

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you ever testified before this Commission?

A. Yes. I have testified in twenty prior proceedings in Oregon, including five PGE general rate cases, UE 283 (2014), UE 262 (2013), UE 215 (2010), UE 197 (2008) and UE 180 (2006), the PGE Opt-Out case, UE 236 (2012), and the PGE restructuring proceeding, UE 115 (2001).

I have also testified in six PacifiCorp general rate cases, UE 263 (2013), UE 246 (2012), UE 210 (2009), UE 179 (2006), UE 170 (2005), and UE 147 (2003) and six PacifiCorp Transition Adjustment Mechanism ("TAM") proceedings, UE 264 (2014 TAM), UE 245 (2013 TAM), UE 227 (2012 TAM), UE 216 (2011 TAM), UE 207 (2010 TAM), and UE 199 (2009 TAM), as well as the PacifiCorp Five-Year Opt-Out case, UE 267 (2013).

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 180 proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also prepared affidavits that have been filed with the Federal Energy Regulatory Commission and prepared expert reports in state and federal court proceedings involving utility matters. My involvement in the determination of avoided costs dates back to the initial Qualifying Facility ("QF") buyback rates established for the Utah Power & Light Company in 1984.

<u>Overview and Conclusions</u>

Q. What is the purpose of your opening testimony in this proceeding?

A. My testimony addresses Question 6 in the UM 1610 Phase II Issues List: "Do the market prices used during the Resource Sufficiency Period sufficiently compensate for capacity?" I am not testifying regarding any other issues in Phase II.

Q. Could you briefly explain the Commission's current implementation scheme for avoided cost compensation during the Resource Sufficiency Period and the Resource Deficiency Period?

A. As explained in Order No. 14-058, the Commission requires electric utilities to set rates based on the cost of a proxy resource during periods of resource deficiency and on monthly market prices during periods of resource sufficiency. The Resource Deficiency Period is determined in each utility's Integrated Resource Plan ("IRP") and it is the period for which a deferrable planned resource is identified. The proxy resource is a natural gas combined-cycle combustion turbine proxy resource for standard avoided cost prices, and the next avoidable renewable resource identified in the electric company's IRP for renewable avoided cost prices. The total fixed costs of the avoided proxy resource are allocated to on- and off-peak prices. Non-standard avoided cost rates for large QFs are negotiated between the utility and the individual QF using the standard avoided cost rates as a starting point, with specific guidelines and methodologies approved by the Commission.[1]

In the PacifiCorp service territory, rates for avoided cost purchases for QFs that are 10 MW or less are presented in Schedule 37, which contains pricing provisions for both standard avoided cost rates and renewable avoided cost rates. For Portland General Electric, the analogous rate schedule is Schedule 201, and for Idaho Power Company, it is Schedule 85.

Q. What is your primary conclusion and recommendation to the Commission on the question of whether market prices used during the Resource Sufficiency Period sufficiently compensate for capacity?

A. I have concluded that the market prices used during the Resource Sufficiency Period do not sufficiently compensate for capacity in the PacifiCorp territory. There are two fundamental reasons for this conclusion.

The first is that there is a structural problem in the way the PacifiCorp IRP is interpreted for determining QF pricing. Specifically, in the IRP, small QFs are presumed to extend their contracts upon expiration – and this very assumption is then embedded in determining the value of QF capacity, resulting in a logical circularity. To remedy this problem, the assumption in the IRP that small QFs extend their contracts upon expiration should be eliminated for the purpose of determining QF pricing. This would require the development of an Alternative IRP scenario that re-determined the preferred resource portfolio absent the

[1] Order No. 14-058 at 8.

(assumed) renewing QFs in order to properly value the capacity that QFs would avoid. I want to be clear that I am not challenging how PacifiCorp plans for how QFs renew their contracts, as it is my understanding that most small QFs enter into PURPA contracts when their current contracts expire. While it is appropriate to assume that small QFs renew their contracts for *planning* purposes, this is not an appropriate assumption for QF *pricing*.

The second reason is that the extraordinarily long sufficiency period indicated by the 2015 PacifiCorp IRP is sending a price signal to prospective QFs that the long-term value of their capacity has no value except for the relatively small premium that may be included in the price of firm energy based on projected market prices. This price signal is sent despite the fact that: 1) the development of rules by the Environmental Protection Agency ("EPA") under the auspices of Section 111(d) of the Clean Air Act is creating significant uncertainty with respect to the Company's long-term resource plan; and 2) PacifiCorp itself is planning on a series of significant investments in environmental upgrades to *retain* its coal capacity. I find this dichotomy to be a source of concern. It strikes me as unwise to be signaling to QFs, particularly renewable QFs and zero-emitting QFs, that their capacity is of little long-term value, and consequently discouraging their development, at a time when new environmental regulations are placing long-term resource planning in a state of flux. This seems particularly unwise when it is understood that development of renewable QFs and zero-emitting QFs is encouraged by the pending environmental rules as a means of gaining compliance. Meanwhile, far from eschewing investment in capacity as suggested nominally by the designation of a sufficiency period based on the next deferrable resource in the IRP, PacifiCorp is in reality planning on making significant investments in capacity *retention* that the Company will ask customers to pay for.

In light of these circumstances, I recommend that the Commission adopt an interim capacity pricing mechanism for Schedule 37 sales by renewable QFs and zero-emitting QFs until the uncertainty surrounding implementation of Section 111(d) is resolved. This approach would be used until the state plans implementing the Section 111(d) rules are binding upon PacifiCorp. Under this interim approach, the value of capacity from renewable QFs and zero-emitting QFs would be determined by the net present value of the revenue requirement associated with environmental upgrades that are planned for the sufficiency period. For a renewable QF or zero-emitting QF entering a contract during the interim period, the capacity value would be added to the energy price until the pricing in the contract was governed either by the displaceable renewable IRP resource or displaceable IRP thermal resource, whichever is applicable to that contract. In other words, this adjustment to the capacity value only applies during the resource sufficiency period prices.

The mechanics for performing this calculation are presented in detail later in my testimony.

<u>Assumed Renewal of Small QF Contracts</u>

Q. What does PacifiCorp assume with respect to the continuation of small QF contracts after contract terms expire?

A. According to the 2015 IRP, PacifiCorp assumes that these contracts are extended when they expire.[2]

Q. Do you have any concerns or objections to this assumption?

A. I do not object to this assumption in the context of the IRP being used in its traditional role as a planning tool. That is, for *planning* purposes, it is reasonable to assume these contracts are extended, so as to avoid planning to construct or acquire duplicative facilities. REC witness John Lowe addresses in more detail contract renewals by existing QFs.

However, it is important to make a distinction when it comes to using the IRP for *determining QF prices*. In that limited context, it is <u>not</u> reasonable to assume that small QF contracts are extended when contracts expire because that assumption produces a logically circular result. That is, when the purpose of the exercise is to determine the value of QF capacity, the act of assuming that all or a portion of the QF capacity that is being valued simply "shows up" via contract extension improperly predetermines the answer to the valuation question – and will understate the value of the QF capacity.

Q. Do you have a simple example to illustrate this point?

A. Yes. Assume for illustrative purposes that a utility has 300 MW of small power QF generation selling power under standard fixed avoided cost contracts and that all of these contracts expire five years from now. For simplicity, further

[2] PacifiCorp 2015 IRP, Vol. I, p. 75.

assume that front-office transactions are near their planning maximum, load growth is flat, and there are no planned changes regarding other resources over the IRP time horizon. Under the assumptions used by PacifiCorp to value QF capacity, all 300 MW of small power QF capacity will be assumed to extend their contracts and continue to be in service from Year 6 through the end of the IRP planning horizon. Under the current method, the IRP would indicate that the Company was in a sufficiency period throughout the remainder of the time horizon and that no capacity payment (other than what is attributed to purchases of firm energy based on projected market prices) was required.

Yet it is easy to comprehend that, but for the assumption that small QF contracts were extended, the utility would require 300 MW of capacity at the end of Year 5. Properly done, the pricing method should be crediting QFs with the value of this avoided capacity. This would occur if, for the purpose of determining the value of QF capacity, the analysis assumed that QF contracts were <u>not</u> renewed at expiration. But as it is, the method yields no credit to the QFs for avoiding this capacity due to the logical circularity of the analysis that assumes that the QFs (whose value the analysis is supposed to determine) are providing this capacity, effectively for free, through their assumed contract renewals.

Q. Does the assumption that small QF contracts are renewed upon expiration have a material impact on the valuation of QF capacity?

A. According to PacifiCorp's Response to Data Request REC 8.5, Confidential Attachment REC 8.5, 122 MW of QF contracts that expire prior to

2028 are assumed to be extended in the 2015 IRP. In certain circumstances, relaxing this assumption could potentially move the deficiency period for thermal capacity up by a year, perhaps, depending on the amount of capacity attributed to the renewing QFs and how close front-office transactions are to their maximum levels. However, relaxing this assumption is not likely to have a material impact in the current IRP, for which the next thermal resource is strongly driven by the planned retirement of the Dave Johnson units in 2027, rather than the projected level of front-office transactions.

Q. What is your recommendation to the Commission on this issue?

A. I recommend that for the limited purpose of determining the capacity value of QF pricing under Schedule 37, the Commission require PacifiCorp to identify an Alternative IRP scenario that removes the assumption that small QFs will extend their contracts upon expiration. This Alternative IRP scenario would be used to help determine the year of the next deferrable resource for the purpose of valuing QF capacity.

Q. Are you taking a position on the Phase II issue regarding the appropriate forum for disputed avoided cost inputs and assumptions?

A. No. My recommendation would apply if the Commission takes up avoided cost input and assumptions in an expanded IRP process or in an avoided cost review after the utilities file their avoided cost rates. The analysis regarding the capacity value of small renewing QFs will be necessary regardless of the specific forum that the Commission decides to use when addressing the inputs and assumptions used to set avoided cost rates.

Uncertainty Surrounding Compliance with Proposed Section 111(d) Rules

Q. Please explain your concerns regarding the pricing of QF capacity in the context of the uncertainty surrounding PacifiCorp's compliance with EPA's proposed Section 111(d) rules.

A. Currently, PacifiCorp's Schedule 37 indicates that the sufficiency period for which no thermal resource deferrals will be recognized in QF capacity prices extends until the end of 2023, a very long period. The preferred portfolio in the Company's 2015 IRP indicates that the sufficiency period will extend even further – until the end of 2027. This extraordinarily long sufficiency period is sending a price signal to prospective QFs that the long-term value of their capacity is worth very little. At the same time, the Company is facing the challenge of compliance with EPA's proposed Section 111(d) rules, which propose significant reductions in greenhouse gas emissions. The proposed rules are creating significant uncertainty with respect to the Company's long-term resource plan. An important policy question that the Commission should consider is whether it is wise to be signaling to QFs, particularly renewable QFs and zero-emitting QFs, that their capacity is of little long-term value, and consequently discouraging their development, at this critical time of changing environmental regulations. This question is particularly important when it is understood that development of renewable QFs and zero-emitting QFs are encouraged by the pending environmental rules as a means of gaining compliance.

Q. Please describe EPA's proposed Section 111(d) rules.

A. EPA's proposed Section 111(d) rules are intended to limit carbon dioxide emissions from existing power plants. The proposed rules, which are being promulgated under Section 111(d) of the Clean Air Act, require states to submit a 111(d) compliance plan to the EPA in the 2016 to 2018 timeframe. Subject to EPA approval of these plans, states will be required to submit interim reports to the EPA beginning in 2022 to demonstrate interim goals are being met before achieving full compliance by 2030.

In the proposed rule, the EPA identified emission reduction goals for each state based on its formulation of best system of emission reduction, which is made up of four building blocks: (1) heat rate improvements at existing coal-fueled resources; (2) increased utilization of natural gas resources; (3) increased deployment of renewable resource and zero-emitting resources; and (4) increased end-use energy efficiency. The EPA applied the four building blocks to the loads and resources in each state as a whole. Each state may propose how to meet its goal and is not required to achieve emission reductions in the same manner as that used by the EPA to calculate the goal.

The proposed rule is currently in the midst of a comment period and a final rule is expected later in 2015. States will be required to submit compliance plans by 2016, although extensions are possible. The rule is likely to be subject to extensive litigation.

Q. Does PacifiCorp's 2015 IRP take compliance with Section 111(d) into account?

A. Yes. However, as the rule is not final and is the focus of extensive commentary and criticism, for planning purposes, compliance planning necessarily must consider a range of rule outcomes and interpretations. As PacifiCorp states in its IRP:

> In this IRP, the Company provides extensive analysis of potential future resource portfolios under a variety of compliance approaches to the EPA's proposed Clean Power Plan. However, *significant uncertainty regarding the implementation of this program continues to exist*. Once final, the rule is likely to be subject to litigation, the outcome of which may not be known for many years. In addition, the makeup of the final rule and the manner in which states choose to implement the program will have a significant impact on ultimate compliance approaches and similarly may not be known for some years.[3]

Q. How does the uncertainty surrounding implementation of Section 111(d) impact the formulation of the 2015 IRP?

A. To develop a preferred portfolio in the 2015 IRP, PacifiCorp necessarily had to make certain assumptions regarding implementation of the final rule. For example, all 2015 IRP cases defined as having a 111(d) emission rate target assume, for compliance purposes, that the Company can allocate *system* renewable energy toward meeting emission rate targets in any given state. The 2015 IRP also assumes that a flexible allocation of "111(d) attributes" from renewable resources is applied to cumulative Class 2 DSM energy efficiency savings from Idaho and California, where PacifiCorp does not have a 111(d) compliance obligation. Further, this Company's base case compliance approach assumes that two distinct attributes (RPS attributes and 111(d) attributes) can be used for compliance independent of one another. If the final rule permits a

[3] Id., Vol. I, p. 28. Emphasis added.

flexible allocation of renewable energy and select Class 2 DSM energy efficiency savings, as well as independence of attributes, as PacifiCorp assumes, the Company will benefit because this approach does not lead to any incremental system costs from adding resources for the purpose of meeting 111(d) requirements and results in the lowest cost compliance action.[4]

However, not all versions of the final rule will produce lowest-cost outcomes for the Company. For example, PacifiCorp has prepared a sensitivity case S-15, which assumes that state renewable portfolio standard ("RPS")-eligible RECs and 111(d) attributes must be surrendered at the same time. As explained in the 2015 IRP:

> Linking the Washington RPS program to 111(d) would force PacifiCorp to meet its share of the state 111(d) emission rate target with situs assigned renewable resources, or alternatively, PacifiCorp could eliminate its Washington 111(d) compliance obligation by retiring Chehalis at the end of 2019. Considering the low emission rate targets proposed by EPA in its 111(d) rule for Washington, a significant amount of situs assigned renewables would be required to offset emissions from Chehalis. For this sensitivity, PacifiCorp assumes a lower cost alternative *would be to retire Chehalis at the end of 2019*. With this early retirement, sensitivity case S-15 includes incremental FOTs and DSM resources, along with a *2020 west side natural gas peaking resource*.[5]

Obviously, sensitivity case S-15 produces a different thermal sufficiency period for QF pricing than does the preferred portfolio. And while PacifiCorp may advocate for adoption of a final rule that incorporates the flexibility assumed in the preferred portfolio, the disposition of this issue is yet to be determined.

[4] Id., Vol. I, pp. 140, 154.
[5] Id., Vol. I, p. 207. Emphasis added.

Q. What are the implications for Oregon QF pricing of the resource planning uncertainty engendered by 111(d)?

A. With the final rule yet to be decided, and with litigation certain to follow, the Commission should reflect on whether it is in the public interest to send a price signal to Oregon QFs that for an extended upcoming period, capacity from renewable QFs and zero-emitting QFs has virtually no value, particularly since increased output from renewable resources and zero-emitting resources constitute one of EPA's four building blocks. In my opinion, in light of these considerations, it would be reasonable to recognize some capacity value for renewable QFs and zero-emitting QFs in Schedule 37, at least on an interim basis, while the uncertainty surrounding the implications of 111(d) on the Company's resource planning is being sorted out.[6]

Q. On what basis should a capacity value be derived during this interim period?

A. PacifiCorp is planning a series of environmental upgrades to keep its coal plants operating. These upgrades represent planned investment in capacity *retention*. As such, the planned expenditures are indicative of the valuation the Company is placing on capacity during the IRP sufficiency period. I believe it is reasonable to use the projected per-kW revenue requirement associated with these investments in capacity retention to value the capacity contribution from renewable QFs and zero-emitting QFs while the implications from 111(d) are being determined.

[6] While certain resources are both renewable and zero-emitting, others, such as certain hydro resources, may not be classified as "renewable" for purposes of Schedule 37, but are nonetheless zero-emitting. Other resources may be renewable, but are not necessarily zero-emitting. My recommendation is directed to QFs that demonstrate either one of the characteristics of being renewable or zero-emitting (or of course both).

Q. What environmental upgrades is PacifiCorp planning?

A. According to the 2015 IRP,[7] the Company has the following environmental upgrade projects identified for planning purposes, recognizing that agency, regulator, and joint owner perspectives on acceptability have not necessarily been determined:

- Hayden 1 Selective Catalytic Reduction ("SCR") by Jun 2015
- Jim Bridger 3 SCR by Dec 2015
- Hayden 2 SCR by Jun 2016
- Jim Bridger 4 SCR by Dec 2016
- Craig 2 SCR by Jan 2018
- Naughton 3 Conversion by Jun 2018
- Craig 1 SCR by Aug 2021
- Hunter 1 SCR by Dec 2021
- Jim Bridger 2 SCR by Dec 2021
- Jim Bridger 1 SCR by Dec 2022
- Colstrip 4 SCR by Dec 2022
- Huntington 1 SCR by Dec 2022
- Colstrip 3 SCR by Dec 2023
- Hunter 3 SCR by Dec 2024
- Cholla 4 Conversion by Jun 2025

Q. How can this information be used to derive a capacity value for renewable QFs and zero-emitting QFs during your proposed interim period?

A. The cost information for these projects can be used to calculate the weighted average per-kW revenue requirement (on a present value basis) for the portfolio of environmental upgrades that the Company has planned during the Schedule 37 thermal sufficiency period. This value represents the planned cost of capacity retention.

Q. How should this value be calculated?

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[7] Id., Vol. II, pp. 298-299.

A. I have prepared a sample calculation consisting of the first six environmental upgrades listed above using information provided by PacifiCorp in its Confidential Response to REC 5.7. For the purpose of determining the capacity value, I recommend using all of the projects that are identified in the IRP during the sufficiency period. My sample calculation is summarized in Confidential Exhibit Joint QF Parties/101. Step 1 of the calculation is to identify the projected stream of annual revenue requirements for each project. For this purpose I used an approach that is comparable to what PacifiCorp uses for determining the revenue requirement of a deferrable thermal plant in calculating Schedule 37 rates. This stream of revenue requirements is then converted into a nominal levelized annual value over the remaining Oregon depreciable life of the facility and expressed on a per-kW basis for each project.[8] A blended capacity value for the entire portfolio is then determined by taking an average of the individual project per-kW revenue requirements, weighted by installed capacity. The blending occurs on a net present value basis, i.e., after discounting the revenue requirements calculated over disparate time periods to a common starting date.

The resulting per-kW capacity value then can be converted into on-peak energy prices consistent with the Schedule 37 method. For a renewable QF entering a contract during the interim period, this capacity component would be added to the market energy price until the pricing in the contract was governed

[8] Conceptually, this is comparable to the nominal levelized prices calculated by PacifiCorp in its Schedule 37 workpapers, except that I am expressing the value on a per-kW basis rather than on a per-MWh basis as PacifiCorp does.

either by the displaceable renewable IRP resource or displaceable IRP thermal resource, whichever is applicable to that contract.

Q. As a reference point, what is the capacity value that results from the sample calculation you performed?

A. The capacity value that results is $47.00 per kW-year. Using the Schedule 37 method for converting capacity values into on-peak energy charges, this value translates into an on-peak capacity price of $10.25/MWH for a baseload resource, $0.43/MWH for a wind resource, and $1.39/MWH for a solar resource, using the capacity contribution assumptions currently incorporated in Schedule 37. In using the current Schedule 37 capacity contribution assumptions I am not endorsing these assumptions, which I understand are being addressed separately. Also, for purposes of this proceeding, I have treated these prices as confidential because the underlying projected costs of the individual projects are deemed to be confidential by the Company. However, I do not believe that a composite capacity valuation or corresponding composite energy prices should ultimately be viewed as confidential.

Q. Please summarize your recommendation to the Commission regarding the use of environmental upgrade costs to derive a QF capacity value.

A. I recommend that the Commission adopt an interim capacity pricing mechanism for renewable QFs and zero-emitting QFs selling power to PacifiCorp under the Schedule 37 until the uncertainty surrounding implementation of Section 111(d) is resolved. Under this interim approach, the value of QF capacity would be determined by the net present value of the revenue requirement associated with environmental upgrades that PacifiCorp is planning for the sufficiency period. For a renewable QF or zero-emitting QF entering a contract during the interim period, the capacity value would be added to the market energy price until the pricing in the contract was governed either by the displaceable renewable IRP resource or displaceable IRP thermal resource, whichever is applicable to that contract.

Q. Is your recommendation limited just to PacifiCorp or does it have more general applicability?

A. My proposal is limited to PacifiCorp at this time because of its extraordinarily extended sufficiency period. However, my recommendation would have more generic applicability if the sufficiency periods for other utilities became greatly extended while the uncertainty surrounding implementation of 111(d) remained.

Q. Does this conclude your opening testimony?

A. Yes, it does.

REDACTED

(v) geothermal energy located outside the state;

(vi) waste gas and waste heat capture or recovery whether or not it is renewable, including methane gas from:

(A) an abandoned coal mine; or

(B) a coal degassing operation associated with a state-approved mine permit;

(vii) efficiency upgrades to a hydroelectric facility, without regard to the date upon which the facility became operational, if the upgrades become operational on or after January 1, 1995;

(viii) compressed air, if:

(A) the compressed air is taken from compressed air energy storage; and

(B) the energy used to compress the air is a renewable energy source; or

(ix) municipal solid waste;

(b) any of the following:

(i) up to 50 average megawatts of electricity per year per electrical corporation from a certified low-impact hydroelectric facility, without regard to the date upon which the facility becomes operational, if the facility is certified as a low-impact hydroelectric facility on or after January 1, 1995, by a national certification organization;

(ii) geothermal energy if located within the state, without regard to the date upon which the facility becomes operational; or

(iii) hydroelectric energy if located within the state, without regard to the date upon which the facility becomes operational;

(c) hydrogen gas derived from any source of energy described in Subsection (10)(a) or (b);

(d) if an electric generation facility employs multiple energy sources, that portion of the electricity generated that is attributable to energy sources described in Subsections (10)(a) through (c); and

(e) any of the following located in the state and owned by a user of energy:

(i) a demand side management measure, as defined by Subsection 54-7-12.8(1), with the quantity of renewable energy certificates to which the user is entitled determined by the equivalent energy saved by the measure;

(ii) a solar thermal system that reduces the consumption of fossil fuels, with the quantity of renewable energy certificates to which the user is entitled determined by the equivalent kilowatt-hours saved, except to the extent the commission determines otherwise with respect to net-metered energy;

(iii) a solar photovoltaic system that reduces the consumption of fossil fuels with the quantity of renewable energy certificates to which the user is entitled determined by the total production of the system, except to the extent the commission determines otherwise with respect to net-metered energy;

(iv) a hydroelectric or geothermal facility with the quantity of renewable energy certificates to which the user is entitled determined by the total production of the facility, except to the extent the commission determines otherwise with respect to net-metered energy;

(v) a waste gas or waste heat capture or recovery system, other than from a combined cycle combustion turbine that does not use waste gas or waste heat, with the quantity of renewable energy certificates to which the user is entitled determined by the total production of the system, except to the extent the commission determines otherwise with respect to net-metered energy; and

(vi) the station use of solar thermal energy, solar photovoltaic energy, hydroelectric energy, geothermal energy, waste gas, or waste heat capture and recovery.

(11) "Unbundled renewable energy certificate" means a renewable energy certificate associated with:

(a) qualifying electricity that is acquired by an electrical corporation or other person by trade, purchase, or other transfer without acquiring the electricity for which the certificate was issued; or

(b) activities listed in Subsection (10)(e).

HISTORY:

C. 1953, 54-17-601, enacted by L. 2008, ch. 374, § 15; 2010, ch. 119, § 2; 2010, ch. 125, § 2; 2010, ch. 268, § 2.

Effective Dates. —

Laws 2008, ch. 374, § 23 makes the act effective on March 18, 2008.

Amendment Notes. —

The 2010 amendment by ch. 119, effective May 11, 2010, added the language beginning "whether or not it is renewable" in (10)(a)(vi).

The 2010 amendment by ch. 125, effective May 11, 2010, added municipal solid waste to the list of renewable energy sources.

The 2010 amendment by ch. 268, effective May 11, 2010, added compressed air to the list of renewable energy sources.

This section has been reconciled by the Office of Legislative Research and General Counsel.

54-17-602. Target amount of qualifying electricity — Renewable energy certificate — Cost-effectiveness — Cooperatives.

(1)(a) To the extent that it is cost effective to do so, beginning in 2025 the annual retail electric sales in this state of each electrical corporation shall consist of qualifying electricity or renewable energy certificates in an amount equal to at least 20% of adjusted retail electric sales.

(b) The amount under Subsection (1)(a) is computed based upon adjusted retail electric sales for the calendar year commencing 36 months before the first day of the year for which the target calculated under Subsection (1)(a) applies.

(c) Notwithstanding Subsections (1)(a) and (b), an increase in the annual target from one year to the next may not exceed the greater of:

(i) 17,500 megawatt-hours; or

(ii) 20% of the prior year's amount under Subsections (1)(a) and (b).

(2)(a) Cost-effectiveness under Subsection (1) for other than a cooperative association is determined in comparison to other viable resource options using the criteria provided by Subsection 54-17-201(2)(c)(ii).

(b) For an electrical corporation that is a cooperative association, cost-effectiveness is determined using criteria applicable to the cooperative association's acquisition of a significant energy resource established by the cooperative association's board of directors.

(3) This section does not require an electrical corporation to:

(a) substitute qualifying electricity for electricity from a generation source owned or contractually committed, or from a contractual commitment for a power purchase;

(b) enter into any additional electric sales commitment or any other arrangement for the sale or other disposition of electricity that is not already, or would not be, entered into by the electrical corporation; or

(c) acquire qualifying electricity in excess of its adjusted retail electric sales.

(4) For the purpose of Subsection (1), an electrical corporation may combine the following:

(d) approving an energy resource under Section 54-17-402; or

(e) issuing an order under Section 54-17-404 regarding whether an energy utility should proceed with implementing a resource decision.

HISTORY:

C. 1953, 54-17-103, enacted by L. 2005, ch. 11, § 5; 2008, ch. 382, § 801.

Amendment Notes. —

The 2008 amendment, effective May 5, 2008, updated references to conform to the recodification of Title 63.

PART 2

SOLICITATION PROCESS

54-17-201. Solicitation process required — Exception.

(1)(a) An affected electrical utility shall comply with this chapter to acquire or construct a significant energy resource after February 25, 2005.

(b) Notwithstanding Subsection (1)(a), this chapter does not apply to a significant energy resource for which the affected electrical utility has issued a solicitation before February 25, 2005.

(2)(a) Except as provided in Subsection (3), to acquire or construct a significant energy resource, an affected electrical utility shall conduct a solicitation process that is approved by the commission.

(b) To obtain the approval of the commission of a solicitation process, the affected electrical utility shall file with the commission a request for approval that includes:

(i) a description of the solicitation process the affected electrical utility will use;

(ii) a complete proposed solicitation; and

(iii) any other information the commission requires by rule made in accordance with Title 63G, Chapter 3, Utah Administrative Rulemaking Act.

(c) In ruling on the request for approval of a solicitation process, the commission shall determine whether the solicitation process:

(i) complies with this chapter and rules made in accordance with Title 63G, Chapter 3, Utah Administrative Rulemaking Act; and

(ii) is in the public interest taking into consideration:

(A) whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electrical utility located in this state;.

(B) long-term and short-term impacts;

(C) risk;

(D) reliability;

(E) financial impacts on the affected electrical utility; and

(F) other factors determined by the commission to be relevant.

(d) Before approving a solicitation process under this section the commission:

(i) may hold a public hearing; and

(ii) shall provide an opportunity for public comment.

(e) As part of its review of a solicitation process, the commission may provide the affected electrical utility guidance on any additions or changes to its proposed solicitation process.

(f) Unless the commission determines that additional time to analyze a solicitation process is warranted and is in the public interest, within 60 days of the day on which the affected electrical utility files a request for approval of the solicitation process, the commission shall:

(i) approve a proposed solicitation process;

(ii) suggest modifications to a proposed solicitation process; or

(iii) reject a proposed solicitation process.

(3) Notwithstanding Subsection (2), an affected electrical utility may acquire or construct a significant energy resource without conducting a solicitation process if it obtains a waiver of the solicitation requirement in accordance with Section 54-17-501.

(4) In accordance with the commission's authority under Subsection 54-12-2(2), the commission shall determine:

(a) whether this chapter or another competitive bidding procedure shall apply to a purchase of a significant energy resource by an affected electrical utility from a small power producer or cogenerator; and

(b) if this chapter applies as provided in Subsection (4)(a), the manner in which this chapter applies to a purchase of a significant energy resource by an affected electrical utility from a small power producer or cogenerator.

HISTORY:

C. 1953, 54-17-201, enacted by L. 2005, ch. 11, § 6; 2007, ch. 289, § 1; 2008, ch. 374, § 11; 2008, ch. 382, § 802.

Amendment Notes. —

The 2007 amendment, effective March 14, 2007, rewrote Subsection (3), substituting the waiver requirement for a list of conditions justifying waiver and procedures for approving waiver that are similar to provisions in § 54-17-501.

The 2008 amendment by ch. 374, effective March 18, 2008, substituted "60 days" for "90 days" in (2)(f).

The 2008 amendment by ch. 382, effective May 5, 2008, updated references to conform to the recodification of Title 63.

This section has been reconciled by the Office of Legislative Research and General Counsel.

54-17-202. Requirements for solicitation.

(1) The commission shall make rules, in accordance with Title 63G, Chapter 3, Utah Administrative Rulemaking Act, outlining the requirements for a solicitation process. The rules required by this Subsection (1) shall include:

(a) the type of screening criteria an affected electrical utility may use in a solicitation process including the risks an affected electrical utility may consider;

(b) the required disclosures by an affected electrical utility if a solicitation includes a benchmark option;

(c) the required disclosures by an affected electrical utility related to the methodology the affected electrical utility uses to evaluate bids; and

(d) the participation of an independent evaluator in a manner consistent with Section 54-17-203.

(2) If an affected electrical utility is subject to regulation in more than one state regarding the acquisition, construction, or cost recovery of a significant energy resource, in making the rules required by Subsection (1), the commission may consider the impact of the multistate regulation including requirements imposed by other states as to:

(a) the solicitation process;

(b) cost recovery of resources; and

(c) methods by which the affected electrical utility may be able to mitigate the potential for cost disallowances.

HISTORY:

C. 1953, 54-17-202, enacted by L. 2005, ch. 11, § 7; 2008, ch. 382, § 803.

Amendment Notes. —

The 2008 amendment, effective May 5, 2008, updated references to conform to the recodification of Title 63.