Solar ITC Tax Normalization: Limits Solar Growth and Favors Fossil Fuels

Eric Blank and D.R. Richardson[1]
April 2020

Executive Summary
This paper finds that the tax normalization requirements associated with the solar energy investments of regulated for-profit utilities may be skewing utility decision making. This distortion may lead utilities to keep coal plants open longer than necessary and to replace them with new natural gas facilities instead of new solar plants -- even in situations where the solar alternative offers superior economics. As debate ramps up over potentially extending the solar ITC as part of a broader stimulus package, this paper concludes that removing the tax normalization requirements associated with the solar ITC (but not more broadly) could materially benefit customers and utility shareholders, as well as the environment.

I. Background

Expenditures on solar energy generation facilities are eligible for an Investment Tax Credit (ITC) up to 30% of the eligible investment in the project realizable when the project is first placed in service. For many years, unregulated energy companies and other solar project owners have joined with tax equity investors in partnerships that efficiently take advantage of the ITC, depreciation, and other benefits associated with solar facilities.

For regulated electric utilities that recover costs through rates set by public utility commissions (PUCs), however, broader tax normalization rules limit their ability to efficiently monetize the ITC and depreciation benefits.[2] More specifically, for purposes of recovering costs from customers, the tax normalization rules require that the solar ITC and other depreciation benefits must be realized over the economic life of the solar assets (generally 30 years or longer). This is in sharp contrast to how all other solar project owners utilize the full benefit of the solar ITC in the first year when the project is placed in service. In our financial models, this delay in realizing the ITC and depreciation benefits can increase the costs to customers of rate-based solar by as much as 20-30%.

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[1] Eric Blank is a lawyer and economist, who co-founded and co-owns Community Energy, a leading renewable energy company that has developed and built 2,000 MW of wind and solar, including the largest currently operating solar projects in PJM, MISO, and Colorado. Eric has a JD from Yale Law School and a MSc in Economics from the London School of Economics. David "D.R." Richardson is currently a private consultant who previously was a Partner at Vision Ridge Partners, a leading private equity firm investing in multiple pioneering clean energy companies. DR has a BA from Brown University.

[2] Tax normalization requirements apply generally to utility depreciation and not just the solar ITC. See generally Internal Revenue Code, Section 168(f)(2). This paper is suggesting a narrow change to exempt the solar ITC from the tax normalization requirement and is not arguing for the elimination of tax normalization more broadly.

Although some utilities have found ways to work around the tax normalization requirements, these approaches can be complex, risky, and expensive. [3] The current impact of the tax normalization rules has been to limit the ability of many for-profit investor-owned utilities (IOUs) to cost-effectively own and operate new solar facilities. Instead these utilities have had the option to enter into purchase power agreements (PPAs) with third-party solar generators which can be very beneficial for customers, but not necessarily profitable for the utility. Or, some utilities have chosen to pursue alternative non-solar resource investments even if these options have higher costs to ratepayers.[4]

II. Methodology

This paper focuses on the potential choices confronting a sample utility currently running an aging coal plant in the Southwest Power Pool market, to better understand the economic impacts of each choice for both utility customers and shareholders. We assume that the utility has four separate options with the current solar ITC normalization requirements: (1) keep running the existing coal plant, (2) replace the coal plant with a new combined cycle natural gas plant (CCGT) placed into rate base, (3) replace the coal plant with a solar PPA, firmed up by a new peaking resource, or (4) replace the coal plant with a solar plant placed into rate base with tax normalization, firmed up with a new peaking resource.[5] These alternative portfolios are sized to be consistent with the coal plant on either a capacity (for the CCGT) basis or both a capacity and energy (for the solar plus peaking options).

The first option studied is a sample existing coal plant in the Southwest Power Pool (SPP) built 40 years ago, with a 500 MW nameplate capacity, and operating at a net capacity factor just under 40% (not atypical for older coal plants). An existing coal plant has five cost streams associated with keeping it open: ongoing fuel costs, variable O&M, fixed O&M, incremental capital cost, and plant-specific overhead. Based on actual 2018 data from coal plants in and around the SPP market, this paper assumes an all-in incremental cost of $39.50/MWh (covering all five cost categories) for the utility to continue operating the plant. This does not include the sunk capital costs associated with any remaining unamortized investment in the plant.

A second choice is to retire the coal plant and replace it with an equivalent 500 MW natural gas-fired combined cycle (CCGT) unit to match the coal plant on a capacity basis. For the gas CCGT, we've assumed an upfront capital cost of just under $1,100/MW, a full-load heat rate of

[3] For example, Dominion Resources appears to be on its way to solving the normalization problem in Virginia (see generally) https://www.taxequitytimes.com/wp-content/uploads/sites/15/2016/06/Normalization-Dominion-Strategy-Solar-Industry-Article-Burton-2016_mod.pdf, but other utilities have not resolved this concern.
[4] See Generally, Lazard, Levelized Cost of Energy (LCOE) Analysis, Version 13, November 2019, at p. 7 (showing solar as the cheapest resource on a LCOE basis), at https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf.
[5] Our data and spreadsheet is available at https://communityenergyinc.com/press (not available yet).

6,400 MMBtu / kWH,[6] a net capacity factor of 48%,[7] and a delivered natural gas price starting at \$2.50/MMBtu, consistent with early 2020 expectations. We have also assumed that the additional cheaper energy generated by the CCGT, as compared to the now retired coal plant, can be used to partially offset some portion of the annual energy costs associated with the CCGT through sales into the wholesale power market.[8]

Lastly, we examine a portfolio of solar plus peaking capacity as a replacement for the coal plant: 700MW of solar at a 27% capacity factor provides approximately the same energy as the coal plant. Solar, in contrast to coal and gas, has a significantly lower variable cost due to the 'fuel' (the sun) being free. Based on our experience as a solar developer, we assume that the all-in cost of solar in SPP is \$27/MWh flat for 30-years and that the cost of building the new solar is \$0.70 watt / DC (or \$0.84 / watt AC assuming a DC to AC ratio of 1.2). Given that SPP provides solar a capacity value of only 52%, we add a 135 MW peaking resource (either natural gas turbines or storage) to the solar resource so that this portfolio provides equivalent capacity as the other two.

This analysis first assumes that the utility purchases the solar through a Power Purchase Agreement (PPA), which is expensed under traditional utility regulatory approaches such that the purchasing utility is not eligible to earn a profit on it. We then look at the costs of the solar under a rate base scenario with tax normalization. The peaking resource (like the CCGT) is included in rate base and the utility does earn a return. Table 1 below summarizes these inputs.

Table 1 - Portfolio Assumptions

	Existing Coal	CCGT	Peaker	Solar
Capacity (MW)	500	500	135	700
Energy (MWh)	1,708	2,102	83	1,656
Upfront Capital Cost (\$ / kW)	\$0	\$1,084	\$1,000	\$840
Net Capacity Factor	39%	48%	7%	27%
All-in Cost (\$ / MWh)	\$39	\$41		\$27
Escalation	2%	2%		0%

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[6] The input assumptions for the CCGT capital costs, heat rate, O&M, and other parameters come from the US EIA, Capital Cost Study for New Utility-Scale Electric Power Generating Technologies, December 2019, at pp. 8-1 to 8-7 (prepared by Sargent & Lundy). See https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

[7] CCGTs are capable of higher capacity factors. However, an analysis of LMP pricing at multiple nodes in SPP from 2015 – 2019 suggests that a CCGT would dispatch economically into the market 30-48% of all hours and lose money on a variable cost basis were it to be run at a higher capacity factor. We assume the highest capacity factor from the nodes that were studied.

[8] We assume that the additional energy generated by the CCGT (as compared against the coal plant) could be profitably sold on the wholesale power market at a price premium of \$2.50/MWh based on our analysis of the hourly nodal pricing.

III. Findings

Given these assumptions on basic unit economics, the economic impacts on both utility customers and shareholders can be calculated.

Economic Impacts with Tax Normalization

Table 2 below shows the economic impacts to customers associated with the four different scenarios. Continuing to operate the existing coal facility is somewhat less expensive than replacing it with a new natural gas plant on a cost-of-energy basis, largely because of the additional upfront capital costs associated with building the new gas plant. At the same time, however, continuing to operate the coal plant is roughly 20% more expensive than the Solar + Peaker alternative from a customer perspective using a PPA approach. The solar, as firmed up by a peaking resource, provides a similar energy and capacity output at a materially reduced cost. In contrast, because of the inefficiencies associated with tax normalization, a utility decision to rate base the solar is now more expensive than the existing coal plant and on par with the new natural gas. For customers, the Solar PPA + Peaker portfolio is the clear winner.

Table 2 - Portfolio Economics

	Coal	CCGT	Solar + Peaker	Solar + Peaker
Rate-base / PPA	Rate-base	Rate-base	PPA	W/ Normalization
Annual MWh	1,708	2,102	1,738	1,738
Rated Capacity (MW)	500	500	500	500
Annual Cost to Ratepayers				
Variable (Fuel / O&M) Cost ($mm)	$48	$50	$2	$2
Wholesale Benefit ($mm)	$0	$13	$0	$0
Solar PPA ($mm)	$0	$0	$35	$0
Fixed O&M / Overhead Cost ($mm)	$6	$2	$10	$10
Annualized Capital Cost ($mm)	$14	$47	$11	$53
Total Annual Cost ($mm)	**$67**	**$86**	**$58**	**$65**
Levelized Cost of Energy ($/MWh)	***$39***	***$41***	***$33***	***$40***

When the economics of the same resource decision are analyzed from the perspective of utility shareholders, however, a different outcome can occur. Regulated monopoly utilities are only allowed to earn a return or profit on capital investments that are placed into the rate base (and thus utility rates) as approved by state regulators.[9] All other (non-rate based) utility costs are expensed and directly passed through to customers in the rate making process with no profit accruing to the utility.

[9] Utility Price (in any customer segment) = Revenue Requirement / Sales. Revenue Requirement = (Rate Base X Rate of Return) + Expense. As such, utility profit in a regulated monopoly context only arises when new plant and equipment is added to rate base. Solar off-take contracts are considered an expense and do not create profit.

Table 3 below shows the financial impacts to utility shareholders, finding that the CCGT – because of the heavy capital investment – is the most profitable (excluding the solar rate base alternative, given its 20% premium to customers above the solar PPA). The coal plant, with its ongoing capital investment is second, while the Solar + Peaker option is the least profitable of the alternatives as the solar PPA is expensed and only the Peaker is rate-based.

Table 3 - Shareholder Returns

	Coal	CCGT	Solar + Peaker
Rate-base / PPA	Rate-base	Rate-base	PPA + Peaker
Annual MWh	1,708	2,102	1,738
Rated Capacity (MW)	500	500	500
Annual Cost to Ratepayers			
Variable (Fuel / O&M) Cost ($mm)	$48	$50	$2
Wholesale Benefit ($mm)	$0	$13	$0
Solar PPA Cost ($mm)	$0	$0	$35
Fixed O&M / Overhead Cost ($mm)	$6	$2	$10
Annualized Capital Cost ($mm)	$14	$47	$11
Total Annual Cost ($mm)	**$67**	**$86**	**$58**
Levelized Cost of Energy ($/MWh)	***$39***	***$41***	***$33***
Shareholder Return			
Annualized Capital Cost ($mm)	$14	$47	$11
Annualized Shareholder Return ($mm)	**$11**	**$33**	**$8**

This economic analysis shows that, with tax normalization, there is a fundamental mismatch between the best outcome for customers, which is the Solar PPA + Peaker option, versus the most profitable result for utility shareholders, which is the investment in the new natural gas plant (again, excluding the rate base solar with tax normalization). Customers are best served under the Solar PPA + Peaker portfolio, while shareholders may strongly prefer to rate base the capital costs of the CCGT unit. The second most attractive profit alternative for the utility is to continue to operate the coal plant and receive a profit from ongoing capital investments in the plant even though the solar is the most economic for customers. [10]

[10] For the purposes of this paper, we treat any unamortized balance in the coal plant as a sunk cost but support utility reimbursement of these undepreciated investments as an incentive to retire the coal plant and move on to cheaper alternatives.

Economic Impacts without Tax Normalization

The next section of this paper assumes that the tax normalization requirement surrounding the solar ITC is removed, such that regulated utilities could cost effectively invest in new solar and place those investments in their rate base without any adverse economic consequences. As shown in Table 4 below, if utilities can rate-base solar assets with no tax normalization, returns to shareholders increase significantly, while costs to ratepayers stay low. This makes the Solar + Peaker portfolio the most profitable path forward for utility shareholders. Given the substantially lower costs to ratepayers of the Solar + Peaker portfolio, that path becomes the clear optimal economic choice for both utility customers and shareholders.

Table 4 - Shareholder Returns With Rate-Basing of Solar Without Normalization

	Coal	CCGT	Solar + Peaker	Solar + Peaker
Rate-base / PPA	Rate-base	Rate-base	PPA	Rate Base, No Norm.
Annual MWh	1,708	2,102	1,738	1,738
Rated Capacity (MW)	500	500	500	500
Annual Cost to Ratepayers				
Variable (Fuel / O&M) Cost ($mm)	$48	$50	$2	$2
Wholesale Benefit ($mm)	$0	$13	$0	$0
Solar PPA Cost ($mm)	$0	$0	$35	$0
Fixed O&M / Overhead Cost ($mm)	$6	$2	$10	$10
Annualized Capital Cost ($mm)	$14	$47	$11	$46
Total Annual Cost ($mm)	**$67**	**$86**	**$58**	**$58**
Levelized Cost of Energy ($/MWh)	***$39***	***$41***	***$33***	***$33***
Shareholder Return				
Annualized Capital Cost ($mm)	$14	$47	$11	$46
Annualized Shareholder Return ($mm)	**$11**	**$33**	**$8**	**$34**

IV. Implications

Despite the attractive economics of solar, this paper has shown that under reasonable assumptions and circumstances, regulated monopoly utilities may not have a financial incentive to retire coal plants and replace them with solar, even when it is a better outcome for customers. As a result, in regulated markets coal plant retirements may be materially delayed. And when those coal plants are retired, utilities will find it more profitable to replace the asset with a natural gas plant, which may be a significantly worse outcome for customers as this example suggests. In contrast, when utilities find ways to profit from pursuing the cheapest alternatives, they can move very quickly in new directions.

As Table 5 below shows, there is a wide divergence in the percentage of coal plant retirements by region. In organized markets and in certain states perhaps where decision making may be based on environmental as well as economic criteria, coal plant retirements are moving forward aggressively. In other markets, particularly regulated markets in SPP, the southeast, and parts of MISO, coal plant retirements are occurring much less rapidly.

Table 5: Coal Plant Capacity and Retirements (as of Q3 2019)[11]

Region	Total Coal Capacity (MW)	Announced Retirements (MW)	Percent Retiring	Remaining Plants (MW)
WECC	24,094	11,242	47%	12,852
SPP	23,580	720	3%	22,860
MISO/Midwest	67,722	9,778	14%	57,944
Southern Region	57,812	2,208	4%	55,604
ERCOT	14,285	1,230	9%	13,055
PJM	51,529	7,115	14%	44,414
NE / NY / Other	1,917	603	31%	1,314
Total	240,939	32,896	14%	208,043

As a solar developer active in these markets, we believe that solar (appropriately firmed up with a peaking resource) provides roughly a similar capacity and energy resource at a substantially lower cost in many situations much like the example in this paper. This belief is confirmed by multiple comprehensive modeling studies by individual utilities and other third parties.[12] For us, the perverse financial incentives for regulated monopoly utilities associated with solar ITC tax normalization are likely a material part of the slow-down in coal plant retirements that would otherwise be driven by the economics.

Likewise, recent reports on new gas-fired generation suggest that utilities and independent power producers are also planning to build just under 70 GW of new natural gas-fired generation before 2025 and perhaps as much a 100 GW by 2030.[13] This is all in addition to the delayed coal plant retirements. These same reports also tend to find that a substantial portion

[11] Data in the table was compiled from EIA (https://www.eia.gov/electricity/data/eia860/) and FERC Form 1 (https://www.ferc.gov/docs-filing/forms/form-1/data.asp).

[12] See, e.g., https://www.pacificorp.com/energy/integrated-resource-plan.html (results of a PacifiCorp IRP finding that a number of its currently operating coal plants were no longer economic); https://www.xcelenergy.com/company/media_room/news_releases/xcel_energy_to_end_all_coal_use_in_the_upper_midwest (Xcel Energy study supporting the closure of its Midwest coal plants); and https://energyinnovation.org/wp-content/uploads/2019/03/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL.pdf (showing the economics of coal retirement across the US).

[13] See, e.g., "The Growing Market for Clean Energy Portfolios – Economic Opportunities for a Shift from New Gas-Fired Generation to Clean Energy Across the United States Electricity Industry," Rocky Mountain Institute, 2019, p 20, https://rmi.org/insight/clean-energy-portfolios-pipelines-and-plants; "Natural Gas: A Bridge to Climate Breakdown", Energy Innovation, 2019, https://energyinnovation.org/wp-content/uploads/2020/03/Natural-Gas_A-Bridge-to-Climate-Breakdown.pdf.

of this new gas generation is uneconomic given the rapidly improving economics of solar, wind, and storage technologies.[14]

Again, enabling regulated monopoly utilities to invest in solar and cost-effectively place these solar capital expenditures into their rate base may avoid a number of these new gas plants. With an ITC that did not have tax normalization requirements, the most profitable plan for any individual utility would now more often be the cheapest.

Ultimately, we believe that aligning utility and customer incentives will result in substantially more solar – including for independent power producers who want to own solar – as utilities accelerate coal plant retirement and avoid building new gas plants thereby creating enormous new investments in both utility-owned rate base solar and in solar PPA contracts offered to third party generators.[15]

V. Conclusion

It is our understanding that there are ongoing discussions about potentially extending the solar ITC, with several regulated utilities seeking to remove the normalization requirement and solar energy industry advocates fighting to retain it. The analysis in this paper suggests that efforts to maintain tax normalization are a mistake and may be limiting overall growth in solar.

Said another way, clean energy advocates can engage in multi-year, state-by-state fights to either change the fundamental for-profit nature of utility regulation or try to force regulated monopoly utilities into pursuing paths that may not be in their long-term profit interest. As an asset owner with an obligation to provide electricity, regulated monopoly utilities are almost always critical voices in the energy policy debate, if not the determinative one, and these fights may get resolved only slowly, over time.

Alternatively, clean energy and renewable resource advocates can work with the electric utility industry to eliminate the tax normalization rules and fundamentally make solar the most profitable investment for regulated utilities. There may be no magic bullet to accelerate coal plant retirement and avoid endless fights over new natural gas plants but eliminating tax normalization at the federal solar ITC level, particularly as part of any ITC extension, is probably as close as it gets.

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[14] Id.

[15] Examples include Xcel Energy in Colorado placing wind energy in rate base, rapidly shutting down its coal plants, and pursuing 50% of the greatly increased resource need through third-party PPA approaches. See, e.g., Xcel Energy, Leading the Energy Future, May 2018, at p. 8 (describing the Colorado Energy Plan). https://www.xcelenergy.com/staticfiles/xe/PDF/2017%20CR%20Highlights.pdf. Dominion Resources in Virginia has -- as a result of a multi-year effort to avoid tax normalization with the solar ITC – also decided to pursue a mix of rate base and PPA solar.