April 15, 2020

Via electronic mail

Indiana Utility Regulatory Commission
Attn: Research, Policy, and Planning Division
101 W. Washington Street, Suite 1500 E.
Indianapolis, IN 46204-3407
bborum@urc.in.gov

Re: Sierra Club Comments to IPL'S 2020 IRP

Dr. Borum:

On behalf of Sierra Club and our over 10,000 Indiana members, we submit these comments to the Indiana Utility Regulatory Commission regarding Indianapolis Power & Light's 2020 IRP. We believe IPL's 2020 IRP failed to fully assess the benefits that would accrue to customers from accelerating the retirement of all of IPL's high-cost coal units.

In particular, IPL's customers would likely save money if IPL retired Petersburg units 3 and 4 and replaced those units with a diverse portfolio of clean energy resources. As Sierra Club Senior Analyst John Romankiewicz demonstrates in the attached analysis, further investment in Petersburg units 3 and 4 to keep them running through 2030 will likely cost more money than replacing the full Petersburg plant with renewables, storage, and demand-side resources. The attached economic analysis shows why continued operation and investment in the Petersburg plant would in effect be a wasteful investment—pouring customers' money into maintaining an indisputably high cost resource and increasing stranded asset risk for IPL's shareholders.

To avoid replicating this stranded asset risk, any generation replacement of Petersburg units 3 and 4 should be both diverse and clean, not gas. Many of the scenarios that IPL is currently studying emphasize gas replacement or gas as a bridge resource. But, as the attached Romankiewicz study shows, a clean energy replacement portfolio (i.e., no gas combustion turbines or combined cycle units) for the Petersburg coal plant is cost-effective, and avoids sinking additional customer resources into a form of energy that faces significant regulatory and comparative cost risks, as carbon pricing becomes likely and the relative cost of non-carbon generation decreases. Replacing Petersburg with a new gas plant in the current energy context would be a bridge to nowhere; as the Romankiewicz study shows, the services provided by

Petersburg can be cost-effectively replaced entirely by a combination of clean energy resources now, and permanently.

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If you have any questions or would otherwise like to discuss this comment letter, please do not hesitate to contact us. Thank you for your consideration.

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Economic analysis of IPL's Petersburg coal plant and its clean energy replacement

John Romankiewicz, Senior Analyst, Sierra Club Beyond Coal Campaign

March 10, 2020

Coal generation in Indiana has been on a downward trajectory for about a decade, having fallen substantially (Figure 1) from 120 million megawatt hours (MWh) in 2008 to 65 million MWh in 2019, a 47% decrease. Generation from Indianapolis Power and Light's (IPL's) Petersburg plant has fallen, though more modestly, from 12 million MWh in 2008 to 8 million MWh in 2019, a 32% decrease.

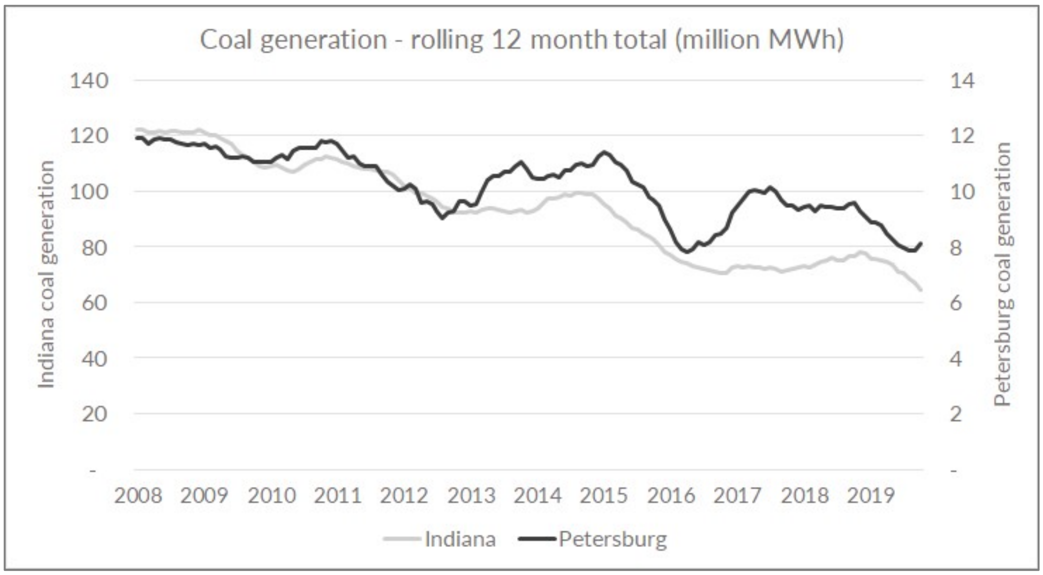

Figure 1: Indiana coal power generation and Petersburg generation

To help inform ratepayers and regulators about the value of these plants to IPL's customers, I modeled expected future costs and revenues of the Petersburg coal plant, first to determine whether Petersburg will be operating at a profit or a loss, and second to compare its future costs to a full clean energy replacement. The following sections walk through my analysis, step by step, before arriving at the final conclusions. I will explain how I derived the inputs for and the assumptions that I made in both calculating the net present value of Petersburg, and also in comparing the economics of these coal plants to a clean energy portfolio (CEP) replacement.

Future performance 2020-2039

In order to estimate the net present value of Petersburg for the period 2020-2039, I constructed a model to project future costs and revenues. To do so, I created starting assumptions or built projections for the following values:

- Capacity factor

- On- and off-peak generation
- Fuel costs
- Variable operations and maintenance expenses
- Fixed operations and maintenance expenses
- Annual capital expenses
- On- and off-peak prices

All of these assumptions and projections are derived from publicly available information. As I note in several places below, many of these estimates are conservative, and the actual performance of Petersburg may be less favorable to customers than my estimates.

Table 1 presents a summary of many of those starting assumptions, with additional details provided below on how I derived each of these assumptions and inputs.

	Capacity factor (2016-2018 avg.)	Fuel costs - 2018 ($/MWh)	Variable O&M costs - 2018 ($/MWh)	Fixed O&M costs - 2018 ($/kW-year)	Capital costs - 2017 ($/kW-year)
Petersburg ST1	75%	$22.01	$4.74	$55.73	--
Petersburg ST2	58%	$21.89	$4.74	$55.73	--
Petersburg ST3	55%	$21.87	$4.74	$55.73	$27.75
Petersburg 4	63%	$21.42	$4.74	$55.73	$27.88

Table 1: Summary of capacity factor, fuel, operations and maintenance, and capital cost assumptions by unit

Capacity factor

I used the average capacity factor for 2016-2018 as our starting assumption for capacity factor each unit in 2020. I then dropped the capacity factor by 1.5 percentage points per year. My analysis is defensible in this respect, given that I would expect coal units to continue to face increasing competition from wind, solar, and gas, and thus for capacity factors to decline over time. The historic average decline over the past 12 years (as fit by the trend line in Figure 2 below) is -0.15%/month or -1.8%/year.

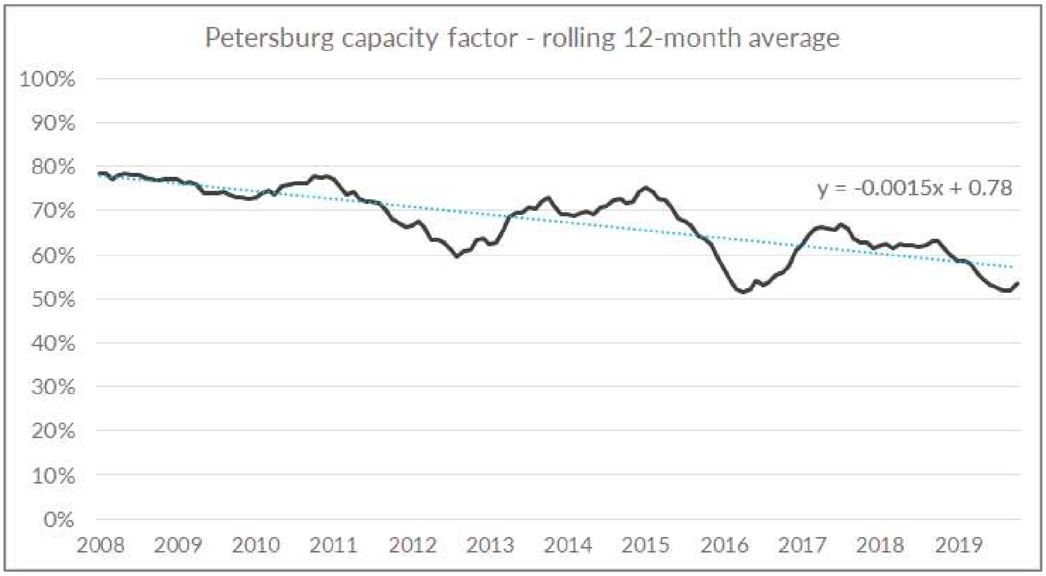

Figure 2: Rolling 12-month average capacity factor for Petersburg coal plant (2008-2019)

Fuel costs

I based fuel costs on data that IPL reported on the U.S. Energy Information Administration (EIA) Form 923 sourced via S&P Global Market Intelligence. Costs have been very stable for the past decade (Figure 3) but may increase in the future. IPL's 2018 fuel costs were used as a starting proxy and inflated by 2% per year. In EIA's 2019 Annual Energy Outlook, delivered coal costs (for the electric power sector) rise by an average of 2.7% per year out to 2039, so this assumption is conservative.

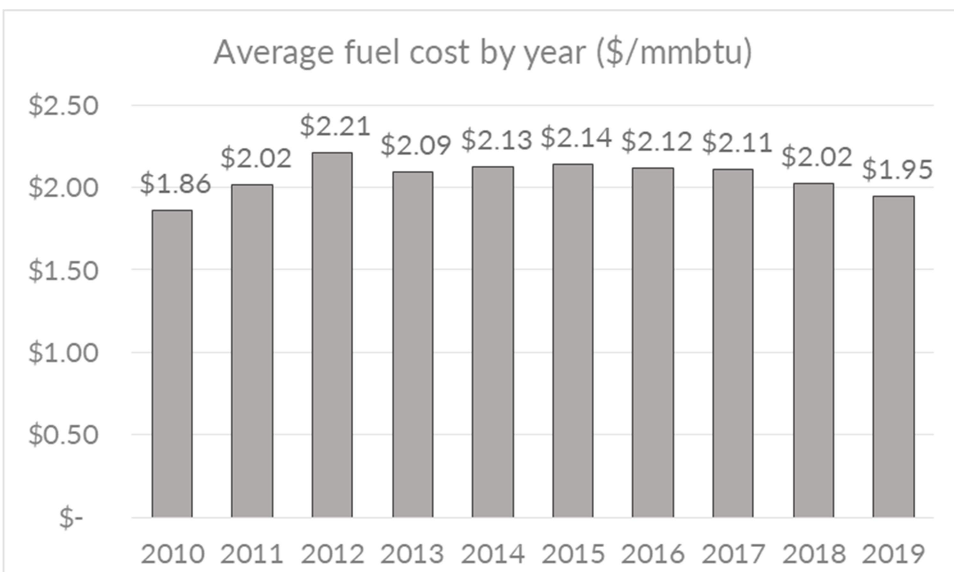

Figure 3: Average annual fuel costs for Petersburg, as delivered ($/mmbtu), 2019 data through June

Variable and fixed operations and maintenance costs

Variable and fixed operations and maintenance costs were based on data that IPL reported on FERC Form 1 via S&P Global Market Intelligence. These 2018 costs were used as a starting proxy and inflated by 2% per year.

Capital costs

Ongoing annual capital additions were calculated according to an equation sourced from EIA's Annual Energy Outlook methodology.[1] EIA found a generalized equation that describes how much coal plant owners spend on capital expenditures on average per year, as a function of coal plant age and whether or not the coal plant had flue gas desulphurization (FGD). For coal plants across the U.S., the range for ongoing capital expenditure is $19-30/kW-year. For Petersburg, the average ongoing capex is on the higher end of the range at $28/kW-year (2017 dollars), which makes sense as all units have FGD installed and the capacity-weighted average age of the units is 43 years. From here, we inflate this figure by 2% per year to account for normal inflation.

$$CAPEX = 16.53 + (0.126 * age) + (5.68 * FGD)$$
$$where\ FGD = 1\ if\ a\ plant\ has\ an\ FGD, 0\ if\ a\ plant\ does\ not\ have\ FGD$$

On- and off-peak prices

In order to forecast on- and off-peak power prices between 2020 and 2039, I multiplied EIA's forecast (from Annual Energy Outlook 2019) for gas delivered to East North Central (an EIA census region which includes Indiana) electric sector customers[2] by the implied heat rate of each unit, since gas is commonly the marginal, price-setting resource in most markets today. The implied heat rate for each plant was calculated by looking at historic on- and off-peak prices (monthly average day ahead on- and off-peak strips) for each plant's respective node and dividing by the average monthly delivered gas price to the Indiana electric sector as reported by EIA.[3] Then, the average of those implied heat rates during the years 2018 and 2019 was taken to represent the heat rate going forward. On-peak implied heat rates ranged from 7.83 to 8.39 mmbtu/MWh while off-peak implied heat rates ranged from 6.06 to 6.29 mmbtu/MWh. The

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[1] EIA Annual Energy Outlook Assumptions p. 14
https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf Accessed 6 Sept. 2019.

[2] The data was pulled using EIA's Excel data browser using the following tag:

AEO.2019.AEO2018NO.PRCE_REAL_ELEP_NA_NG_NA_ENC_Y13DLRPMMBTU.A

[3] The following node was identified for pulling monthly average day ahead on and off-peak prices for Petersburg: IPL.16PETE.AGG.

resulting on-peak prices ranged from $44/MWh in 2020 to $79/MWh in 2039, while the resulting off-peak prices ranged from $33/MWh in 2020 to $59/MWh in 2039 (Figure 4).

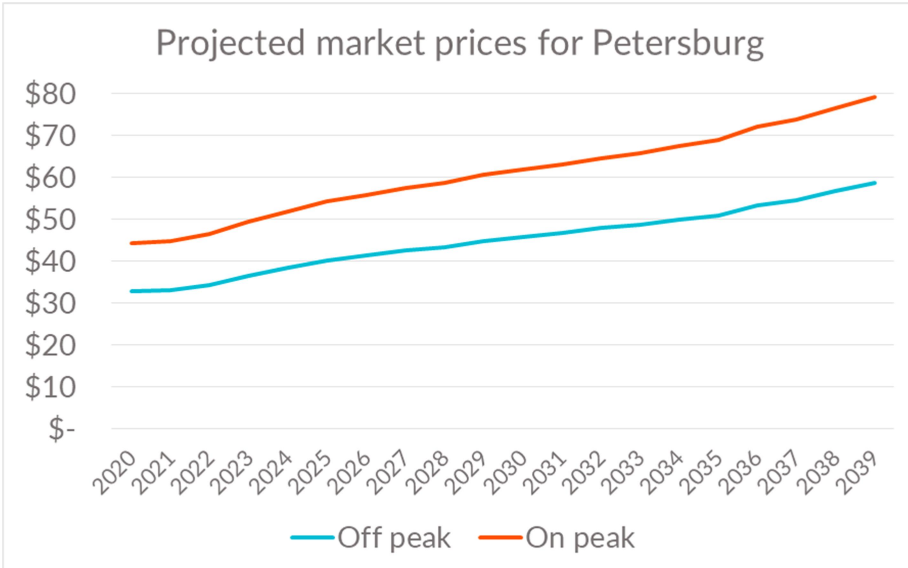

Figure 4: On-peak and off-peak price projections by plant ($ / megawatt hour)

Generation and energy revenue

Annual energy revenue was calculated by multiplying off-peak and on-peak generation by our annual off-peak and on-peak price forecasts. For my analysis, if the capacity factor was over 40%, then the unit was assumed to be generating on-peak for 40% of the year and off-peak for X% of the year where X = capacity factor minus 40%. If the capacity factor was under 40%, then it was assumed to be generating only during on-peak hours. This choice of assumption is a fairly conservative one because even units that are primarily targeting generation during on-peak hours will not exclusively be able to generate during those hours, given various operational constraints such as the time it takes to ramp a facility's capacity up and down.

Calculating net present value and levelized cost of energy

I calculated the sum of energy revenues minus the costs (fuel, variable and fixed O&M, capital) for each year. The net present value (NPV) of those annual sums was calculated using a discount rate of 8%, which is a typical rate used by utilities across the U.S. in integrated resource planning. The levelized cost of energy (LCOE) was calculated by taking an annualized payment of the net present value of all costs (also using a discount rate of 8%) and dividing it by annual generation.

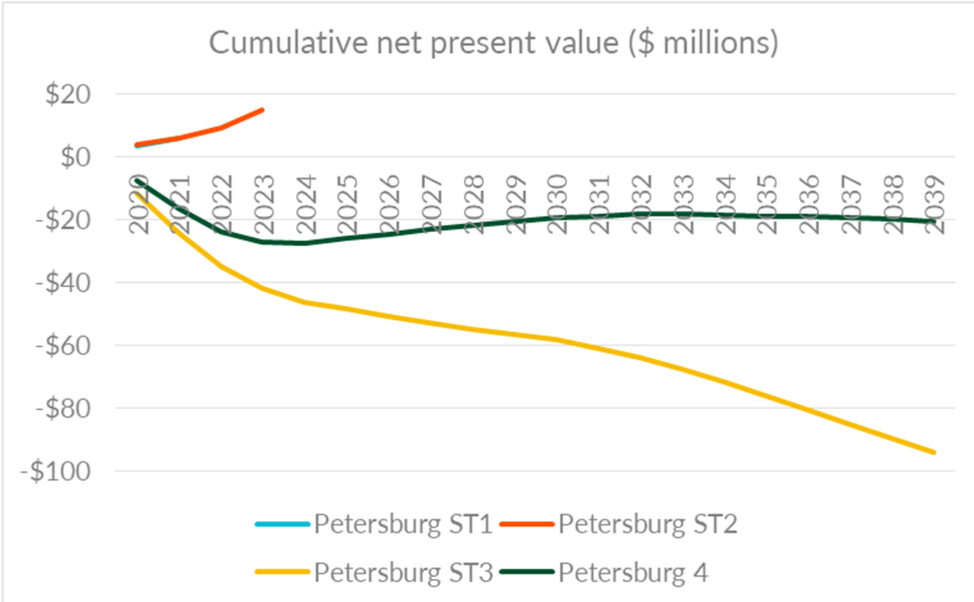

Figure 5: Cumulative Net Present Value for Petersburg units

Simply put, this analysis compares the projected costs of operating these plants to the projected revenues they will receive from the energy market over the next two decades. I found that in aggregate the Petersburg units would lose $94 million over the next two decades. If only considering units 3 and 4, then the losses are $115 million. That is, they would incur $115 million more in costs than the market energy revenues received by the coal plants. Units 1 and 2 have a positive outcome before they close, mostly due to the fact that those two units are not absorbing additional capital investment into the plant. Notably, these results do not include any future environmental regulations that these units may face, and also do not include a price on carbon emissions. In addition, the analysis assumes that the marginal cost of energy in MISO remains linked to the cost of gas generation, which may be an overly conservative assumption. The rapid increase in renewable energy in MISO suggests that marginal energy costs may in fact continue to be depressed relative to the cost of gas. If either of these risks transpire (environmental regulations or a decoupling of market revenues and gas prices), the economic outcome for IPL's coal units will be substantially worse than what is shown here, and my results already show that Petersburg's remaining coal units are either teetering on the margin or outright financial losers on a forward-looking basis. Detailed results can be found in Table 2.

	NPV (2020-2039)	NPV ($/kW-year)	LCOE ($/MWh)
Petersburg ST3	-94m	($8.7)	$57
Petersburg 4	-21m	($1.9)	$53

Table 2: Net Present Value (NPV) and Levelized Cost of Energy (LCOE) for coal units

Clean Energy Portfolio analysis

Given that continuing to run these coal units would be a net cost to ratepayers compared to the energy market, the next step in the analysis is to investigate whether they can be cost effectively replaced with clean energy and on what timeline. For this analysis, I used Rocky Mountain Institute's Clean Energy Portfolio's (CEP) algorithm to identify a suite of clean energy technologies (wind, solar, storage, energy efficiency, and demand response) that could replace the services of the Petersburg coal plant. I used the algorithm and methodology developed by Rocky Mountain Institute (RMI) in Dyson, M., G. Glazer, and C. Teplin's September 2019 report The Growing Market for Clean Energy Portfolios.

A clean energy portfolio, or CEP, is a combination of renewable energy, storage, and demand-side management (DSM) projects that meet the needs of the grid and a utility's customers. We use the term DSM to collectively refer to energy efficiency projects (which lead to a reduction in load) and demand response projects (which lead to the shifting or temporary reduction of load).

The use of CEPs differs from traditional resource planning, which at times focuses on a specific technology. Instead, a CEP looks at how a range of available clean energy resources contribute in each hour of the year, and finds the combination that meets the unique needs of customers at the lowest feasible cost. In this study, the CEPs are constructed to match the energy, peak capacity, and ramping characteristics of the Petersburg coal plant. Portfolios are optimized to satisfy these needs at the lowest cost possible.

The CEPs are conservatively designed to meet peak capacity needs in the top 50 hours of capacity need of the year in the Midcontinent Independent System Operator (MISO), the grid region where IPL and its Petersburg coal plant operate. Some of the 50 peak hours are in the summer, when solar output is high, and some of the hours are in the winter, when solar output is low. As such, the CEP must not rely on solar alone, but rather a complement of wind, solar, storage, and demand-side management technologies. The CEP also must meet the monthly energy requirement of the coal plant's total generation in each month of the year 2017. The CEP algorithm errs on the side of caution, in the sense that other grid resources (like existing gas plants or market purchases) play no role in the replacement, but those resources are typically included in system dispatch or capacity expansion models that utilities typically utilize in portfolio analysis. In other words, the CEP algorithm accounts for a complete energy and capacity replacement of the coal plant without the benefit of any other existing grid resources.

Lastly, I created two scenarios: one scenario where energy efficiency and demand response technologies are part of the coal plant replacement (Mid DSM) and one scenario where they are not (No DSM). In the former scenario, I assumed that energy efficiency and demand response could only comprise up to 25% of the replacement energy and capacity of replacement portfolios, respectively. In the latter scenario, only wind, solar, and battery storage technologies are used.

I populated the RMI model framework with storage and renewable cost assumptions from Lazard's Levelized Cost of Energy v11 and BNEF's New Energy Outlook 2018, both industry standard reports. In addition, the modeling includes the solar investment tax credit, excludes the wind production tax credit, and excludes an investment tax credit for storage (even though many storage projects qualify for the ITC by pairing with solar). Any excess energy that renewables produced above and beyond the coal plant was valued at \$27/MWh, which was the off-peak average price in MISO in 2018. The levelized costs of the CEPs were compared against the LCOE's calculated for the coal units in the prior section, which were in the range of \$53-57/MWh.

I found that the "No DSM" CEPs of wind, solar, and storage could serve as cost effective replacements for Petersburg by 2025, with no consideration of energy efficiency or demand response as resource options, and with consideration of the many conservative assumptions that I have built into this analysis as noted throughout. In the second scenario, once energy efficiency and demand response technologies were incorporated into the modeling (Mid DSM), the cost effective replacement dates moved up to 2018, respectively (see Figure 6). The detailed portfolios can be seen in Table 3. Given that the Mid-DSM scenario requires very high levels of efficiency and demand response (relative to historic levels achieved by IPL), there is likely a middle scenario where the cost effective year for the CEP would be prior to 2025 and involve several hundred megawatts of cost-saving energy efficiency and demand response.

In summary, my analysis shows that the Petersburg plant is high cost today when compared to the energy market, and IPL should therefore be exploring more cost effective replacements. Further, I have shown that IPL's customers would likely benefit if Petersburg was replaced in the early to mid-2020s with a clean energy portfolio of wind, solar, storage, and demand-side technologies that replace the coal plants' energy and capacity services and do so at a lower cost than the continued operation of the coal plants.

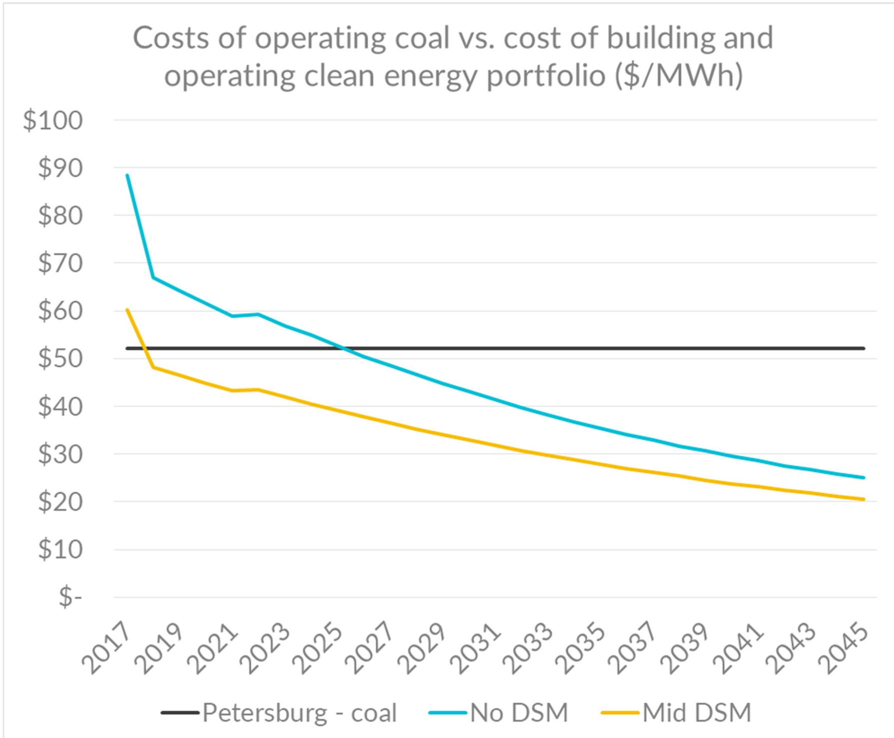

Figure 6: Petersburg vs. Mid-DSM and No-DSM clean energy portfolio replacements

Plant	Scenario	Solar	Wind	Storage	Efficiency	Response
Petersburg	No DSM	2,387	1,984	1,300	0	0
Petersburg	Mid DSM	1,410	1,789	691	859	671

Table 3: Clean energy portfolio makeup (megawatts) based on plant and replacement scenario