STATE OF IOWA

BEFORE THE IOWA UTILITIES BOARD

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IN RE:	)	
	)	DOCKET NO. RPU-2019-0001
INTERSTATE POWER AND LIGHT	)	
COMPANY	)	

DIRECT TESTIMONY OF UDAY VARADARAJAN

On Behalf of

Environmental Law & Policy Center and
Iowa Environmental Council

August 1, 2019

Q. Please state your name and business address for the record.

A. My name is Uday Varadarajan. My business address is 1111 Broadway, Oakland, CA 94607.

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

A. I am a Principal at Rocky Mountain Institute's (RMI) Electricity Practice and a Precourt Energy Scholar at Stanford's Sustainable Finance Initiative (SFI), where I conduct financial, policy, and regulatory analysis to help drive a just transition to clean energy.

Q. Please describe the Rocky Mountain Institute.

A. RMI is an independent, nonpartisan nonprofit cofounded in 1982 by Amory Lovins, RMI's chairman emeritus and chief scientist. RMI engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables.

Q. Please summarize your professional and educational qualifications.

A. Before joining RMI and Stanford, I was a Principal at Climate Policy Initiative Energy Finance (CPI-EF), where I managed CPI-EF's San Francisco team. At CPI, I led the development of financial, regulatory, and policy data analytics and tools to help consumers, utilities, and communities in states across the United States (including New York, Colorado, Missouri, Minnesota, and Utah) realize the benefits from a just and equitable transition from uneconomic dirty resources to clean energy – with a focus in the last few years in particular on the potential benefits of financial tools such as ratepayer-backed bond securitization. Prior to my role at CPI, I served as a program examiner in the U.S. White House Office of Management and Budget (OMB), where I oversaw the budget for U.S. Department of Energy (DOE) energy efficiency and renewable energy programs and the cost assessment and approval of the first $8 billion in DOE loans to automakers, including loans to Tesla and Nissan to build electric vehicles. Before joining OMB, I was an AAAS Science and Technology Policy Fellow at the Department of Energy and then on detail to the staff of the U.S. House of Representatives, Appropriations Committee. Prior to my time in Washington, DC, I was a postdoctoral fellow in theoretical physics in the Weinberg Theory Group at the University of Texas at Austin. I received an AB in Physics from Princeton University and an MA and Ph.D. in Physics from the University of California, Berkeley.

Q. Have you previously filed testimony in a regulatory proceeding?

A. Yes. I have previously filed testimony in regulatory proceedings focused on depreciation rates and financial mechanisms in the states of South Carolina (Docket Nos. 2017-370-E; 2017-305-E; 2017-207-E – V.C. Summer nuclear plant cost recovery, on behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy), Colorado (16A-0231A – depreciation rate revision, on behalf of Western Resource Advocates), Minnesota (E015/GR-16-664 – rate case, on behalf of several Minnesota Clean Energy Organizations), and New York (15-E-0302 – large scale renewables program, on behalf of NYSERDA).

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

A. I am testifying on behalf of the Environmental Law & Policy Center and the Iowa Environmental Council, collectively "ELPC/IEC."

Q. What is the purpose of your direct testimony?

A. My testimony and exhibits support the position of the Environmental Law & Policy Center and the Iowa Environmental Council that Interstate Power and Light (IPL or "the

Company") could accelerate its plans to add low-cost renewable resources while reducing rates – rather than increasing them – by accelerating the retirement of the Company's increasingly uneconomic fossil generating assets.

Q. Please summarize IPL's request for a rate increase and its relationship to IPL's coal and gas generators.

A. IPL's application to the Board in the docket states that the company is requesting "an increase in annual revenues of $203.6 million, to recover the costs associated with those valuable grid improvements, cleaner generation, and other system improvements."[1] IPL goes on to note specifically that one justification for this increase is that the company has made over $2 billion in investments since its 2016 test year rate case, including in 1000 MW of wind farms, including English Farms and Upland Prairie (470 MW – currently in service), Whispering Willow North, Richland, and Golden Plains (530 MW – expected to be in service during TY 2020).

However, IPL also notes that it has made investments in environmental controls at its Ottumwa plant and Lansing Unit 4 – and has invested significantly over the last decade in its gas and coal plants. In fact, as shown in Figure 1 below, the eight largest of its fossil generators represent 2.5GW of capacity, currently account for $1.2 billion of IPL's rate base and generate over 11 TWh annually.

[1] IPL Application at 2.

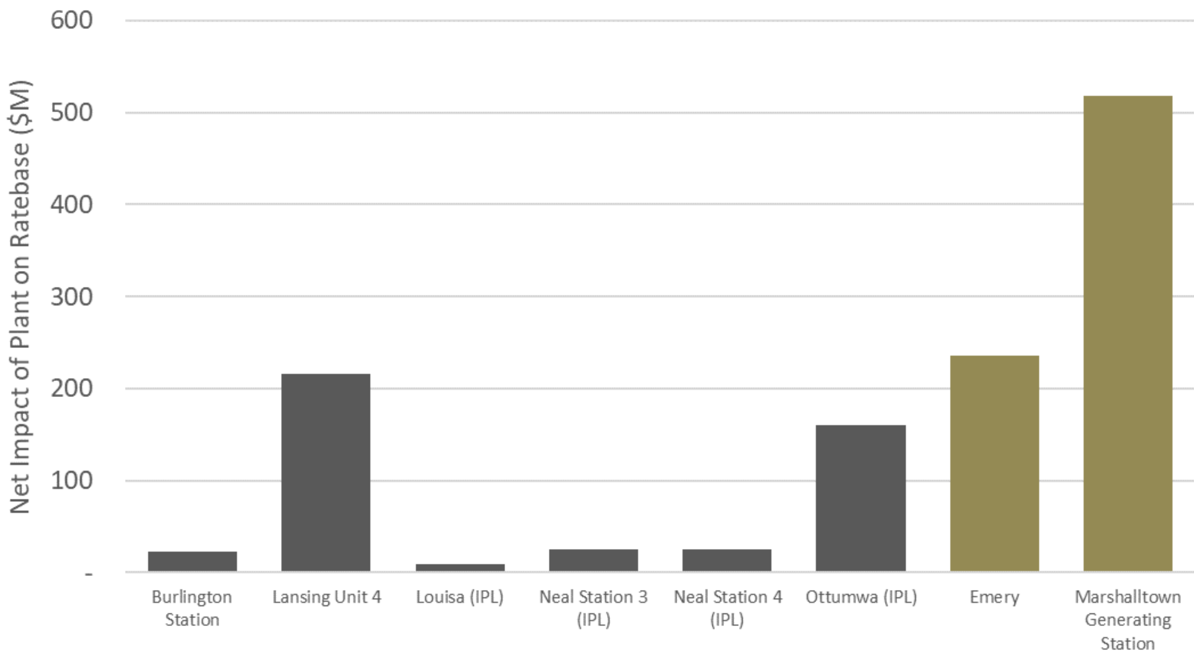

Figure 1: The estimated net impact of IPL's eight large generators on ratebase.[2]

Q. How does IPL's revenue requirement relate to IPL's coal and gas generators?

A. The majority of IPL's fossil generation revenue requirement comes from the fuel, operating and maintenance (O&M) expenses. I estimate that these eight generators account for nearly $494 million in annual revenues required, roughly $200 million to cover capital costs and $294 million to cover anticipated fuel, operating, and maintenance expenses. See Figure 2 below. For comparison purposes, note that wind assets do not have fuel costs and their impact on revenue requirements are primarily to cover capital costs. IPL estimates that the 470 MW of capacity at the English Farms and Upland Prairie wind farms have annualized O&M expenses of $9.8 million, for roughly 1.2 TWh of annual generation.[3]

[2] RMI analysis of IPL's 2018 FERC Form 1 filing of depreciation data at the plant and account level.

[3] IPL Ashenfelter Direct Exhibit 6 (Interim)(E), WP B-5(a):11-12

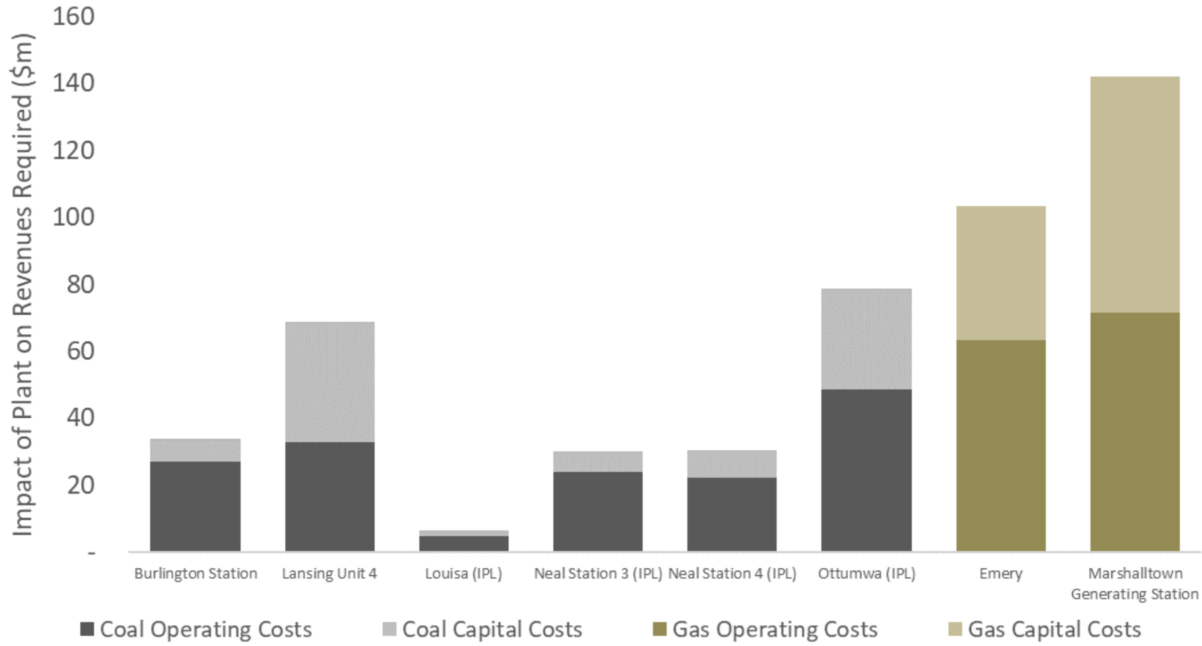

Figure 2: Estimated impact of IPL's eight large generators on revenues required in 2020.[4]

Q. Summarize the methodology of your analysis.

A. I performed comparative financial and economic analyses of continued operation of each of the Company's large generators relative to various options for early retirement and replacement of each generator's capabilities.

Q. Please summarize key conclusions and recommendations.

A. My analysis found that:

- Replacing the energy and grid services delivered by IPL's share of each of the company's large generators (Burlington Station, Emery, Neal 3, Neal 4, Louisa, Lansing, Marshalltown Generating Station (MGS), and Ottumwa) with a combination of services purchased from MISO and new wind (with the full production tax credit,

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[4]RMI analysis of IPL's 2018 FERC Form 1 filings, table f1_steam, and table f1_edcfu_epda, *available at:* ftp://eforms1.ferc.gov/f1allyears/f1_2018.zip

such as IPL's 1000 MW of new wind currently in operation or under development and construction, or in most cases even with a phased-down tax credit if in operation between 2021-2023) – could reduce future costs for ratepayers.

- Factoring down each of these assets and replacing the services they deliver with clean energy could benefit ratepayers – and that early retirement and replacement of each of these assets could be in the long-term interest of customers.
- The immediate retirement of Burlington and the IPL share of Neal 3 and Neal 4 with 10-year accelerated cost recovery and replacement of the full market value of the services they delivered to MISO through utility-owned wind with the full PTC could actually lower rates in 2020 by $16 million.
- For remaining large assets there may be one or more potential regulatory options – such as reducing the allowed return on regulatory assets – as well as refinancing options – such as ratepayer-backed bond securitization (if the Iowa legislature was to authorize the board's use of the latter tool) – that could better align both near-term and long-term ratepayer and utility shareholder interests with the retirement and replacement of these assets.

I. <u>Overview of analysis and results</u>

Q. How have you analyzed the economics of each of the Company's large generators?

A. I analyzed the economics of these generators in three phases.

Q. What was the first phase of the analysis?

A. First, I assessed the current cost to ratepayers of each of IPL's solely and jointly owned large generators (Burlington Station, Emery, Lansing Unit 4, Louisa, Neal 3, Neal 4, MGS, and Ottumwa). Specifically, I used publicly-available capital and operating cost data from the IPL's submissions to FERC (Form 1), EIA (Forms 860 and 923), and the Board (2017 depreciation study)[5] to estimate the impact of each of IPL's large generators on the revenues required in a 2020 test year. This analysis assessed both the revenues required to recover operating expenses as well as to allow for recovery of and on any undepreciated capital invested in the generator at IPL's currently authorized depreciation rates and rate of return respectively.

Q. What was the second phase of the analysis?

A. Second, I compared the total cost to ratepayers of each of these assets with the hourly market value of the energy, capacity, and ancillary services each of them have provided over the last five years. To assess the value of these services, I relied on publicly available hourly historical market data over the last five years made available by the Midcontinent Independent System Operator (MISO) including nodal Day-Ahead Locational Marginal Prices (LMPs), Market Clearing Prices (MCP) in the MISO Ancillary Services Market (ASM), annual capacity auction clearing prices, data on day-ahead cleared offers, and historical wind production across MISO.[6] I also used this data to compare the historical market value of these services with potential alternatives to their continued operation such as marginal purchases of energy, capacity, and ancillary services from the market as well as substitution of wind generation to deliver these services.

Q. What was the third phase of the analysis?

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[5] IPL response to OCA-DR-5, filed as ELPC/IEC Varadarajan Direct Exhibit 1

[6] MISO. Market Reports, *available at:* https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports

A. Third, I analyzed the financial feasibility and ratepayer impacts of retiring assets identified as uneconomic and replacing each of them with wind. To do this, I began by identifying uneconomic assets that could immediately be retired and replaced using the cost recovery tools already available to the Board and result in a net benefit to ratepayers while providing timely cost recovery and reinvestment opportunities for the utility. Then, I turn to assessing options for refinancing cost recovery obligations – such as ratepayer-backed bond securitization – that could be employed in the future to facilitate the transition from the remaining uneconomic assets with larger cost recovery challenges due to recent investments in a way that aligns the interests of ratepayers with that of the utility's investors.

Q. Could you summarize the results of the first phase of your economic analysis regarding the current cost of IPL's large generation assets to ratepayers?

A. As shown in Figure 3 below, just the operating costs alone of each of the eight large generators considered (the darker bars) exceed the average price paid by IPL for power purchased from MISO in 2018 as reported on FERC Form 1[7] – $17.27/MWh – as well as the average PPA price for contracts signed in 2017 in the Interior region in DOE's 2017 Wind Energy Technologies market report, $18.93/MWh.[8] For example, according to data provided in EIA's 2018 Form 923's Source and Disposition table, last year, the newly

[7] RMI analysis of consolidated FERC Form 1 data from ftp://eforms1.ferc.gov/f1allyears/f1_2018.zip, table f1_purchased_pwr.
[8] U.S. Department of Energy. 2017. Wind Technologies Market Report. Office of Energy Efficiency and Renewable Energy, *available at:* https://emp.lbl.gov/sites/default/files/2017_wind_technologies_market_report.pdf, p. 51

built Turtle Creek Wind farm sold its power at a price of $17.10/MWh – and that power is under contract for 15 years with IPL.[9]

If we also consider the capital costs that are expected to be recovered through rates for each of these assets (the lighter bars in Figure X), we find that six of the eight assets cost **more than double market prices and prevalent wind PPA prices.** This suggests that replacing the energy generated by each of these assets with purchased power from MISO or through long-term procurement or ownership of wind generators could significantly reduce ratepayer costs.

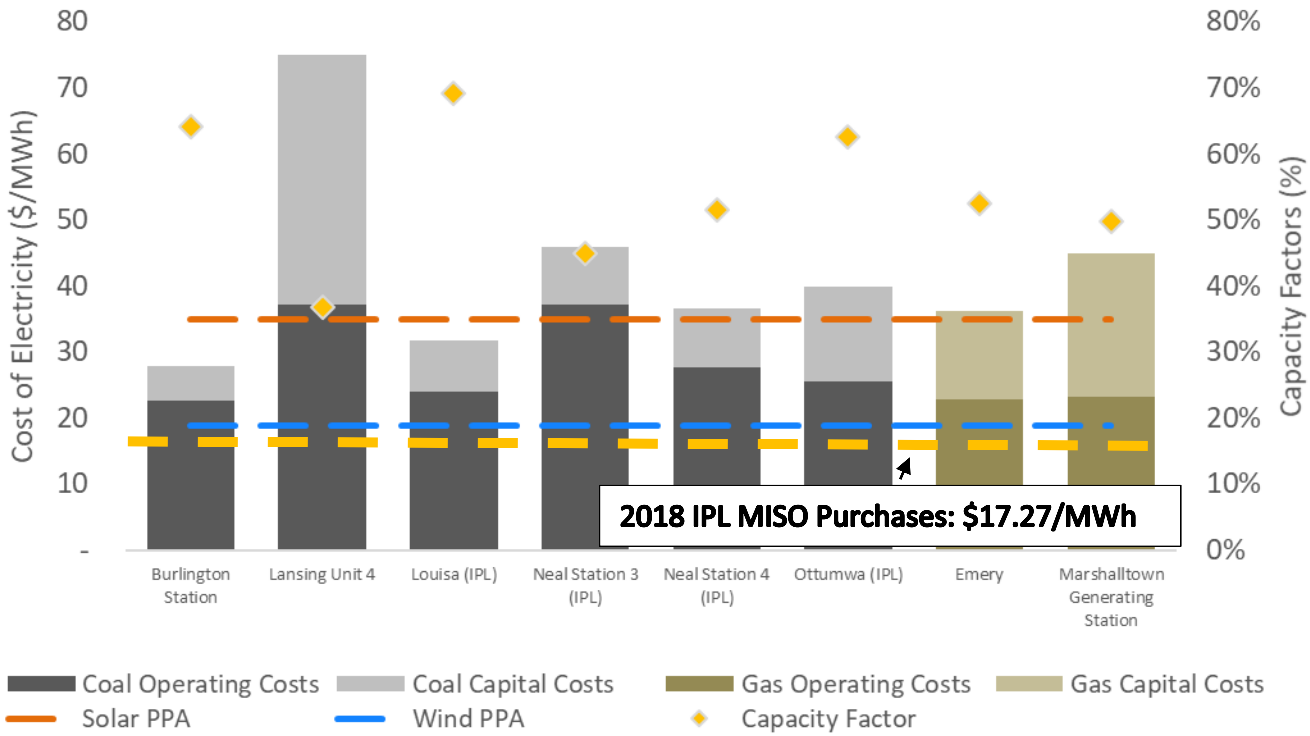


Figure 3: Summary of a cost analysis of IPL's generation assets as compared to prevalent market prices and long-term renewable contract prices.[10]

[9] *Id.*
[10] IPL 2018 FERC Form 1, f1_steam table, f1_purchased_pwr table, and f1_edcfu_epda table); EIA 923; DOE 2017 Wind Technologies Market Report.

Q. What does your analysis imply about the economic viability of the Company's generation fleet?

A. Our analysis suggests that the company could factor down its operations at each of its generation facilities, replacing the energy generated either with purchased power (either through MISO or long-term PPAs, particularly in the near term to capture wind with production tax credits) or with new owned generation (again, wind is quite attractive) and thereby save ratepayers money. As costs for solar and electrical energy storage drop further, and with their continued eligibility for the full investment tax credit for projects that start construction by the end of 2019 and are built by 2023, the same may soon be true for replacement with these technologies as well.

Q. But what about the other services beyond total energy that those plants provide?

A. Coal and gas facilities do provide a broader range of grid services that go beyond the kWh of energy they produce and deliver. The timing of the delivery of energy and its role in providing reliability services – such as regulation and spinning reserves – also have value. For example, a plant that is flexible and able to operate to serve peak demand may be more valuable than an inflexible plant. As IPL operates within MISO's service territory, and since MISO operates day-ahead and real-time markets that value these services, the benefits and costs associated with the delivery of these additional services as well as the hourly variation in the value of the energy delivered should be reflected in market prices.

As the operating characteristics of coal and gas facilities are different, the ancillary services these two classes of generation provide should be assessed independently, and valued based on system need. For example, as gas facilities tend to have more flexibility in their operations, plants like Emery and Marshalltown may be better able to serve peak demand than the coal plants included in the study.

Figure 4 below shows the impact on revenue requirements arising from each of IPL's larger generators from their average operating costs over the last five years as well as due to their current capital costs. Further, the yellow triangles indicate the estimated market value of the services they delivered to MISO including energy, capacity, and ancillary services, calculated based on historically cleared offer, LMP, and MCP data over the last five years that account for the timing and price of each of these services to MISO (along with capacity value).

Finally, much of RMI's research has shown that clean energy technologies, including battery energy storage[11] and distributed energy efficiency and demand response[12] can provide regulation, spinning reserves, and other essential grid services, often at a lower cost than conventional power plants.

Q. What does your analysis of the value of the grid services provided by IPL's plants imply about whether the plants are economic for ratepayers?

A. Figure 4 shows that the average operating costs alone of Lansing Unit 4, Neal Station 3, and Ottumwa exceed the total value of the grid services provided by those units over the

[11] "The Economics of Battery Energy Storage," Rocky Mountain Institute (2015), *available at:* https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_RMI-TheEconomicsOfBatteryEnergyStorage-ExecutiveSummary.pdf

[12] "The Economics of Clean Energy Portfolios," Rocky Mountain Institute, last visited July 31, 2019, *available at:* https://rmi.org/insight/the-economics-of-clean-energy-portfolios/; "Pushing the Limit: How Demand Flexibility Can Grow the Market for Renewable Energy," Rocky Mountain Institute, last visited July 31, 2019, available at https://rmi.org/demand-flexibility-can-grow-market-renewable-energy/.

last five years. That is, they do not provide value commensurate to even the operating costs passed through to ratepayers – and thus, should not continue to operate.

Further, the figure also makes clear that the total cost paid in rates for every one of the assets exceeds the value of the grid services provided – often by a very large margin. That is, ratepayers are paying in some cases double the price that they could be paying to get the same suite of grid services from MISO.

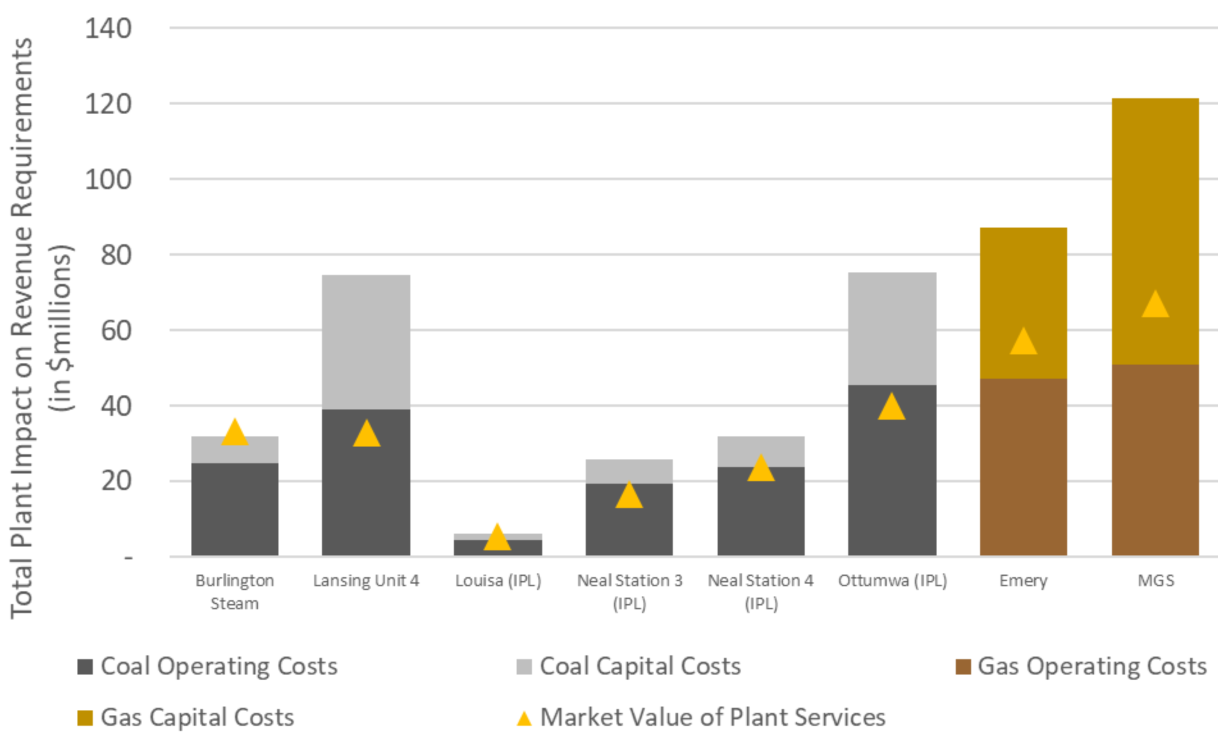


Figure 4: The revenue requirement impacts of IPL's large generators including operating expenses[13] and capital costs[14] compared to the average market value of the energy, capacity, and ancillary services delivered by each asset based on MISO historical data from 2013-2018.

[13] Calculated based on the average operating expenses reported for each facility reported on IPL's 2013-2018 FERC Form 1, f1_steam submissions

[14] Calculated for the 2020 test year based on depreciation data at the plant and account level filed on FERC Form 1, f1_edcfu_epda

Q. Are unrecovered balances an issue for the generating units you examined?

A. See Figure 5 below for a summary of the balance of unrecovered costs (including costs anticipated to be recovered for decommissioning costs net of salvage value) for each of the generating units we analyzed. Four of the units we analyzed – Louisa, Burlington Station, Neal Station 3, and Neil Station 4 – have unrecovered balances and net salvage decommissioning costs well below $100 million each.

However, Lansing Unit 4 and Ottumwa both have seen significant recent investment (largely pollution control equipment arising from a settlement with EPA in 2015) and have substantial costs yet to be recovered, while the two combined-cycle facilities are relatively new and have yet to see their original construction costs fully recovered.

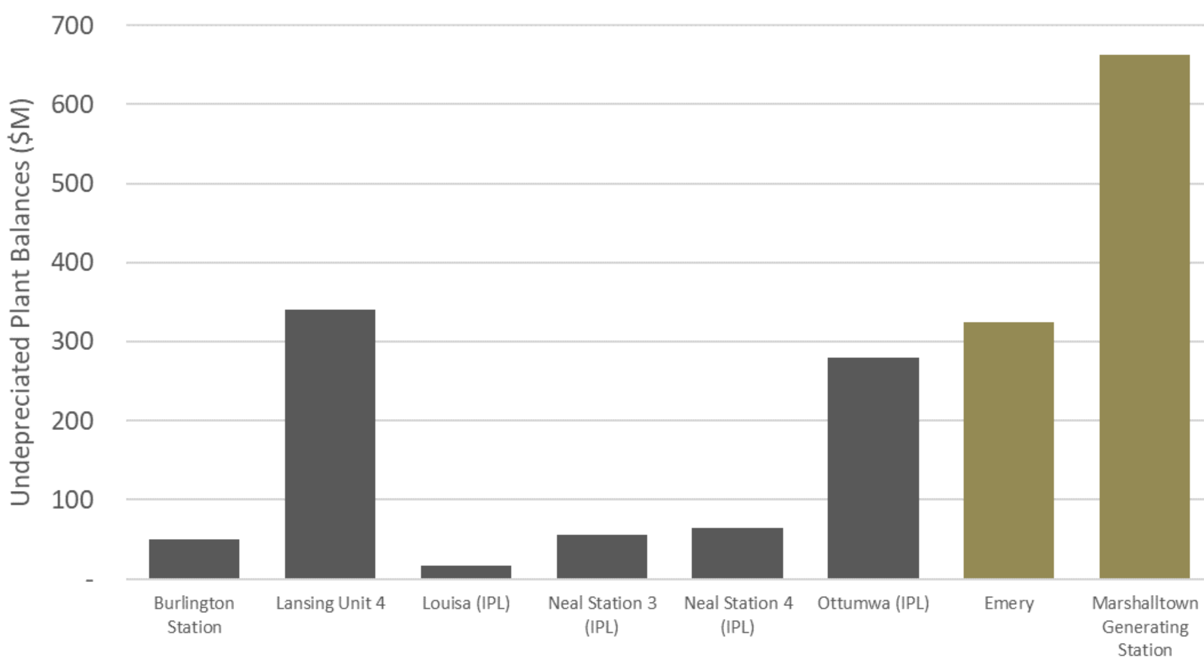


Figure 5: Unrecovered balances for each of the analyzed generators in 2020[15]

[15] Calculated using IPL's 2018 FERC Form 1 depreciation data at the plant and account level reported in f1_edcfu_epda.

Q. Based on your analysis, which of the units could be retired now and benefit ratepayers immediately even with accelerated cost recovery?

A. My analysis suggests that the immediate retirement of Burlington and the IPL share of Neal 3 and Neal 4 with 10-year accelerated cost recovery and replacement of the full market value of the services they delivered to MISO through utility-owned wind with the full PTC could actually lower rates in 2020 by $16 million – see Figure 6 below. Note that this analysis accounts for the fact that the market value of a kWh of wind energy produced by the wind facility may be lower than that of the facility it replaces. It does so by requiring that more wind is built than would be needed to replace the energy generated by the old facility – so as to provide enough value to procure both the replacement energy as well as any replacement capacity and ancillary services required to match the full value of the services that were being provided by the retired asset.

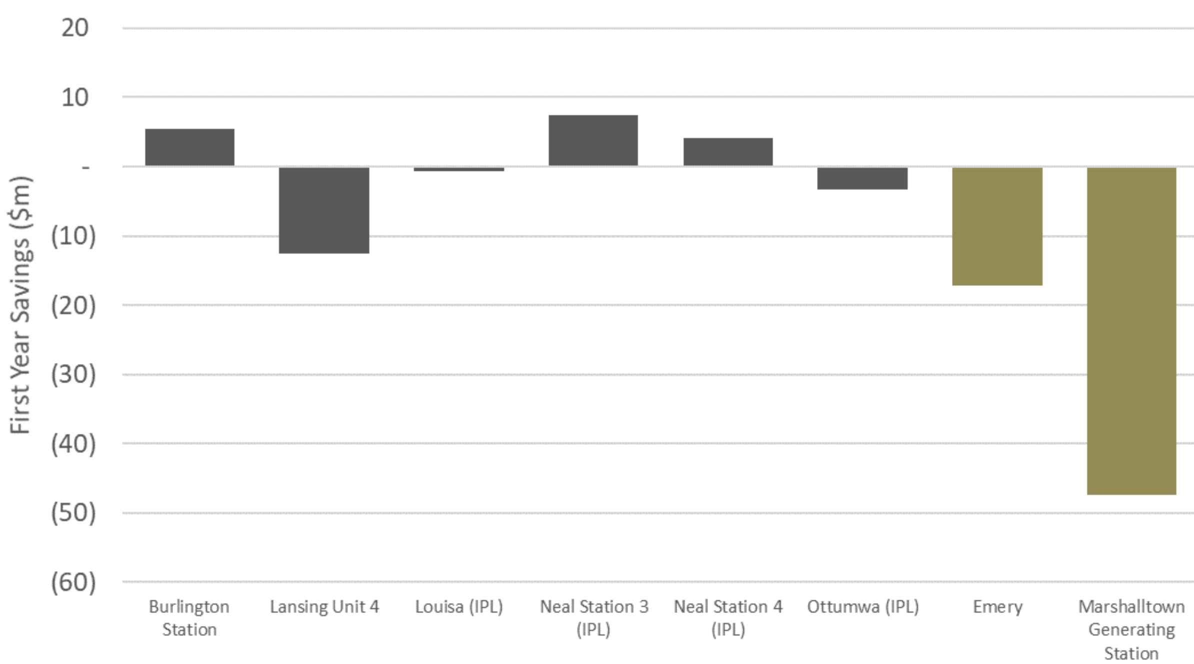


Figure 6: First-year savings from the immediate retirement of Burlington and the IPL share of Neal 3 and Neal 4 with 10-year accelerated cost recovery and

replacement of the full market value of the services they delivered to MISO through utility-owned wind with the full PTC.[16]

Q. And which of the units could be retired now with accelerated cost recovery and benefit future ratepayers?

A. I find that retirement of every one of the eight units with 10-year accelerated cost recovery and replacement of the full market value of the services they delivered through MISO with utility-owned wind with the full PTC would result in savings to future ratepayers on a net-present value (NPV) basis. Figure 7 shows the NPV savings possible for each plant, expressed as savings in levelized cost of electricity over the remaining life of the plant.

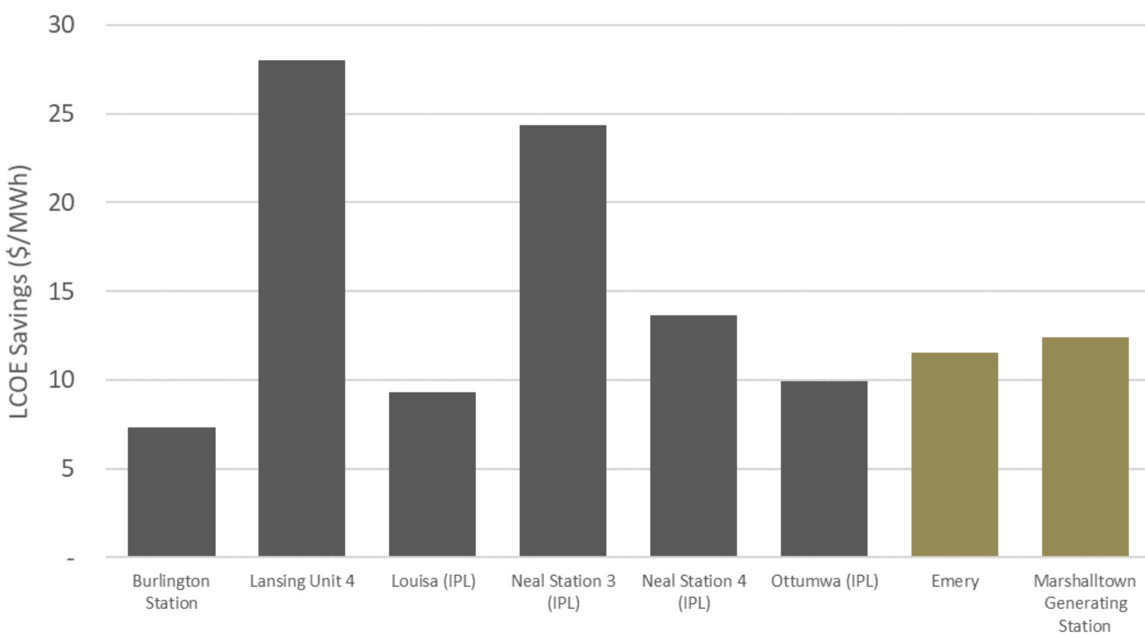


Figure 7: The savings in levelized cost of electricity possible if each of IPL's generators were retired, their costs recovered over ten years, and replaced with wind with full PTC.[17]

[16] RMI analysis based on 2018 EIA 923, 2018 EIA 860, IPL 2013-2018 FERC Form 1, MISO Market Reports from 2013-2018

[17] RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018

Q. Can you elaborate on why Burlington and the Neal Units could be retired and provide savings to ratepayers in the near term?

A. Yes. Let's consider the example of Burlington Station. This asset is expected to have an unrecovered balance of approximately $24 million in 2020, and $26 million in decommissioning costs net of salvage value, for a total of about $49 million in costs yet to be recovered if it is retired early in 2020 (ten years before full cost recovery).[18] The Board could choose to allow accelerated recovery of those costs over ten years and allow the utility to either procure or invest in replacement resources. If we assume that the replacement energy and grid service value is procured through wind with the full PTC (in this case, this would require 1.4 TWh of wind with full PTC, which would correspond to a little over the 1.2 TWh anticipated to be generated by the first 470 MW of the 1000 MW of full PTC wind already being built by IPL), then the savings from wind could be large enough to result in immediate savings to ratepayers as well as over the long term. See, for example, Figure 8 below. Thus, customers would, in this case, see a benefit from early retirement in spite of the outstanding plant balance.

[18] Based on RMI analysis of IPL's 2018 FERC Form 1 submission, f1_edcfu_epda table.

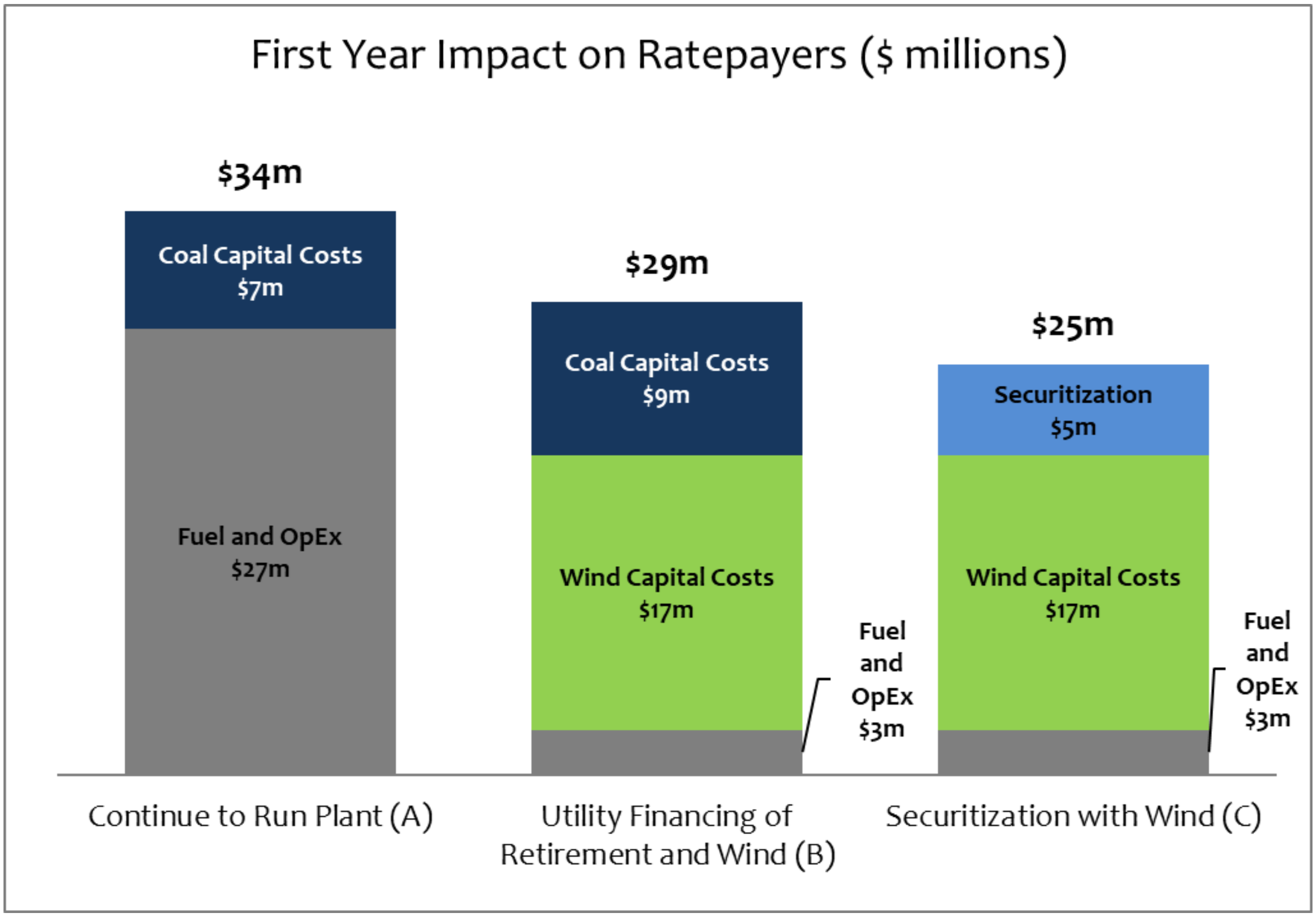


Figure 8: First year rate impact of early retirement of Burlington Station and replacement with utility-owned wind.[19]

Further, from the utility shareholder perspective, as the asset is nearing full cost recovery, there is little capital deployed in the asset. In fact, early retirement can actually pull forward decommissioning costs, which, if capitalized as a regulatory asset can actually allow for an **increase** in anticipated future earnings associated with asset retirement, even if the asset is replaced by purchased power. See Figure 9 below. For utility investors, the possibility of owning replacement generation could provide a meaningful potential upside on top of that increase.

[19] RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018.

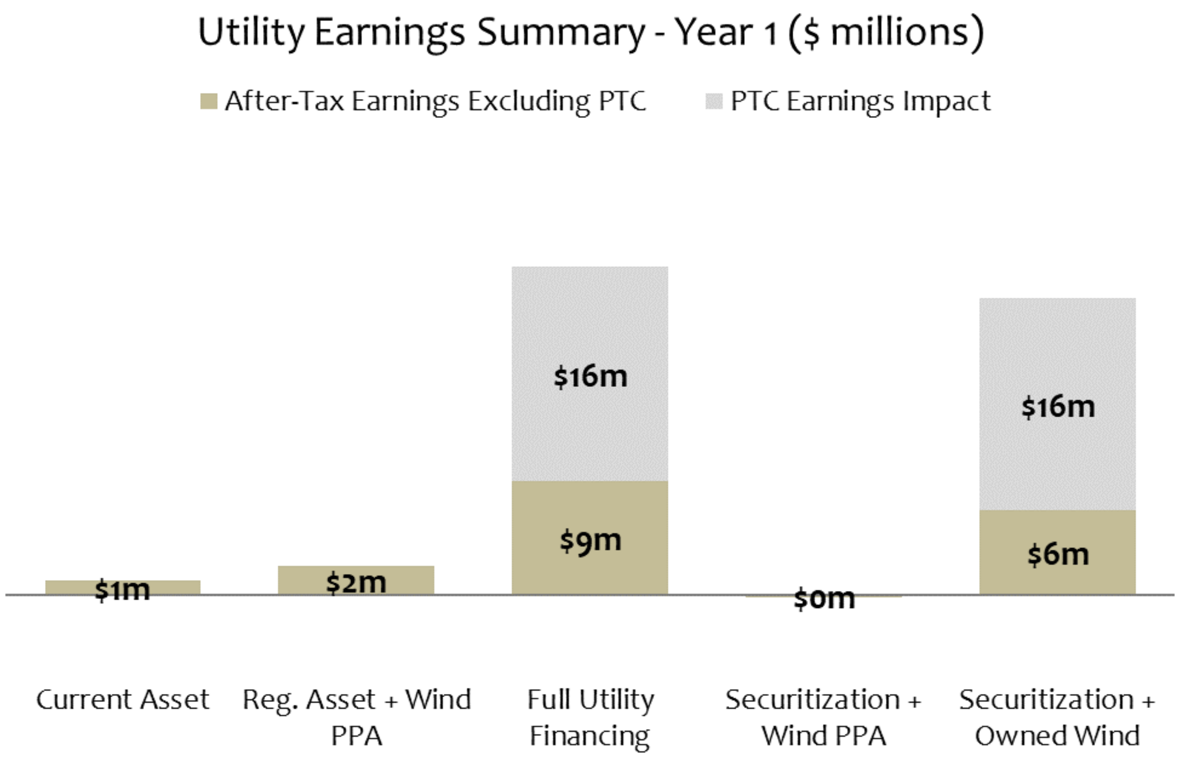


Figure 9: Utility earnings impact of the retirement of Burlington Station and replacement with either a wind PPA or utility-owned wind (Full Utility Financing).[20]

Q. Would there still be benefits from retirement and replacement by new wind with the phased-down PTC?

A. The phase-out of the PTC – down to 80% of its current value for plants that began construction by the end of 2017 and are in operation by the end of 2021, to 60% if in operation by 2022, and 40% if by 2023 – would negatively impact the relative economics of new wind, particularly in the near term. I find that with accelerated cost recovery and 80% of the PTC, only retirement and replacement of Neal 3 still provides immediate savings (see Figure 10). However, savings in the long-term persist for all plants with

[20] 2018 EIA 923, 2018 EIA 860, IPL 2013-2018 FERC Form 1, MISO Market Reports from 2013-2018

replacement by wind with 80% PTC (see Figure 11), and all the generators except for Burlington station with 60% of the PTC (see Figure 12).

Thus, my analysis suggests that there is some urgency to procuring potential replacement resources while the PTC is still at least 80% in effect in order to lock in the greatest benefits to ratepayers.

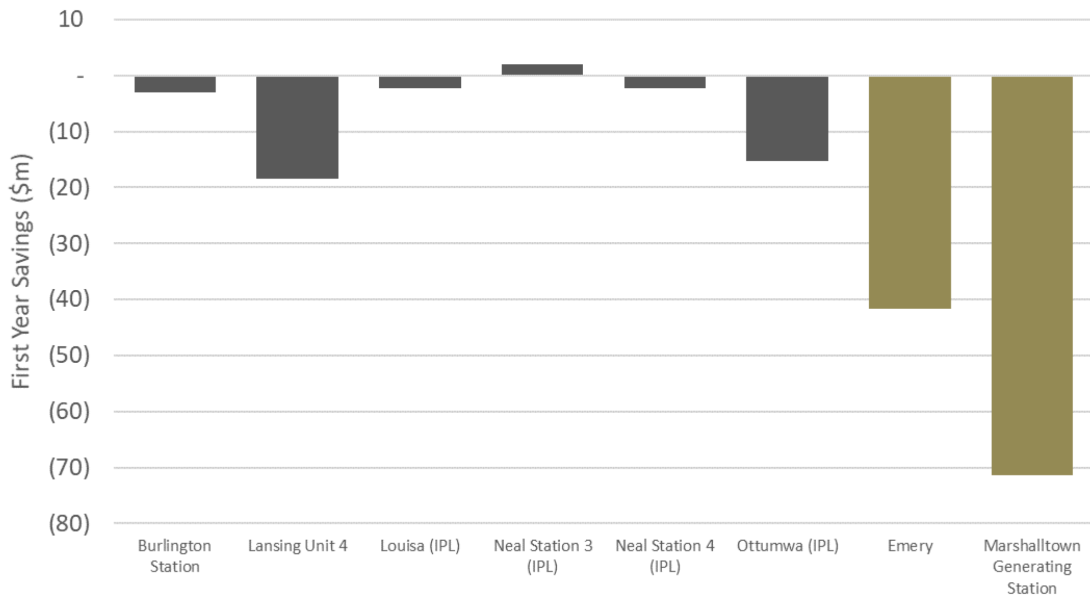


Figure 10: The first-year savings possible if each of IPL's generators were retired, their costs recovered over 10 years, and replaced with wind with 80% PTC.[21]

[21] RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018.

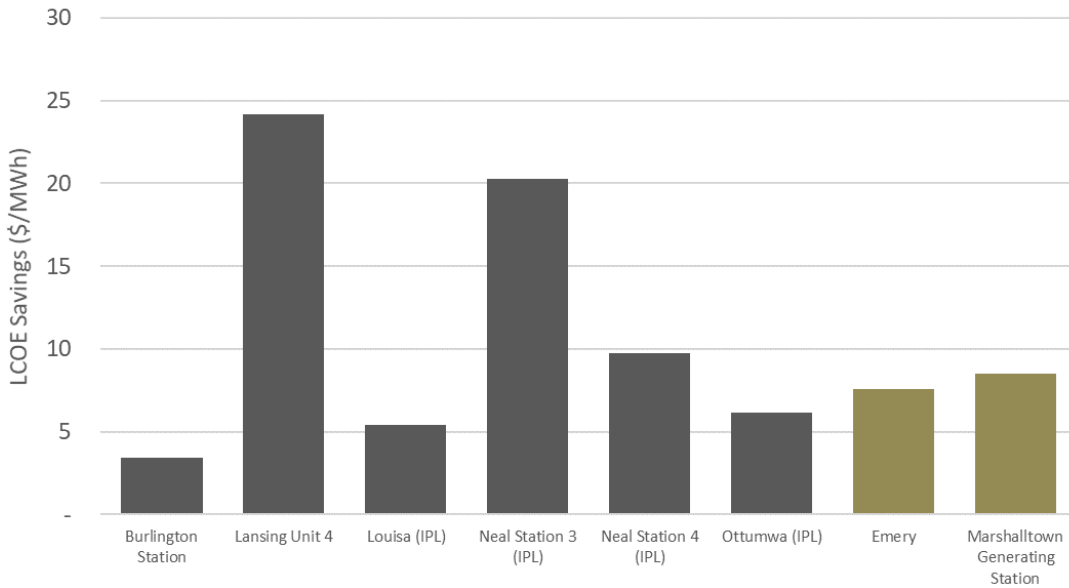


Figure 11: The savings in levelized cost of electricity possible if each of IPL's generators were retired, their costs recovered over 10 years, and replaced with wind with 80% PTC[22]

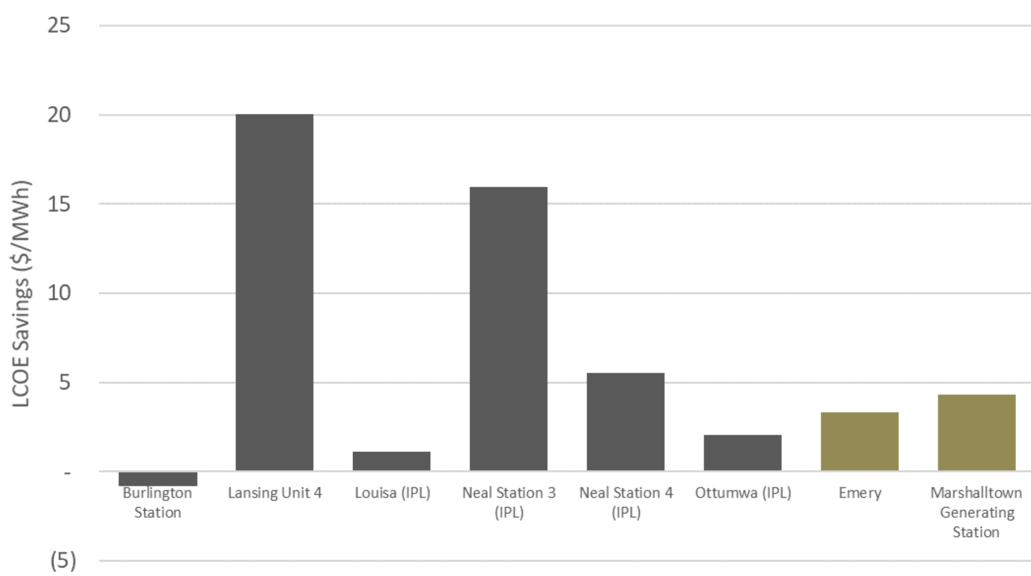


Figure 12: The savings in levelized cost of electricity possible if each of IPL's generators were retired, their costs recovered over 10 years, and replaced with wind with 60% PTC.[23]

[22] RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018

Q. Are there barriers to retiring these assets and realizing significant ratepayer savings?

A. Yes, but only for a subset of plants with significant unrecovered recent investment costs. One particularly important issue that can significantly reduce the attractiveness of retiring any facility early is the challenge of dealing with unrecovered costs.

In general, when a plant is retired early, a utility has usually not yet fully recovered its historical investment in the facility through rates. If those historical costs are still found by a regulator to have been prudently incurred for a facility that was used and useful, then a utility is generally able to argue for timely recovery of those costs through rates, even in the event of early retirement. If that is the case, then early retirement still leaves future ratepayers on the hook to continue paying the capital costs for the retired assets – even if those ratepayers no longer receive any services from the assets – along with the costs for the replacement generation. Often, this motivates regulators to accelerate the recovery of costs for early retirement, resulting in **increased capital costs** for current ratepayers that can sometimes wipe out any benefit from early retirement and replacement in the near

[23] RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018

term. See Figure 11 below.

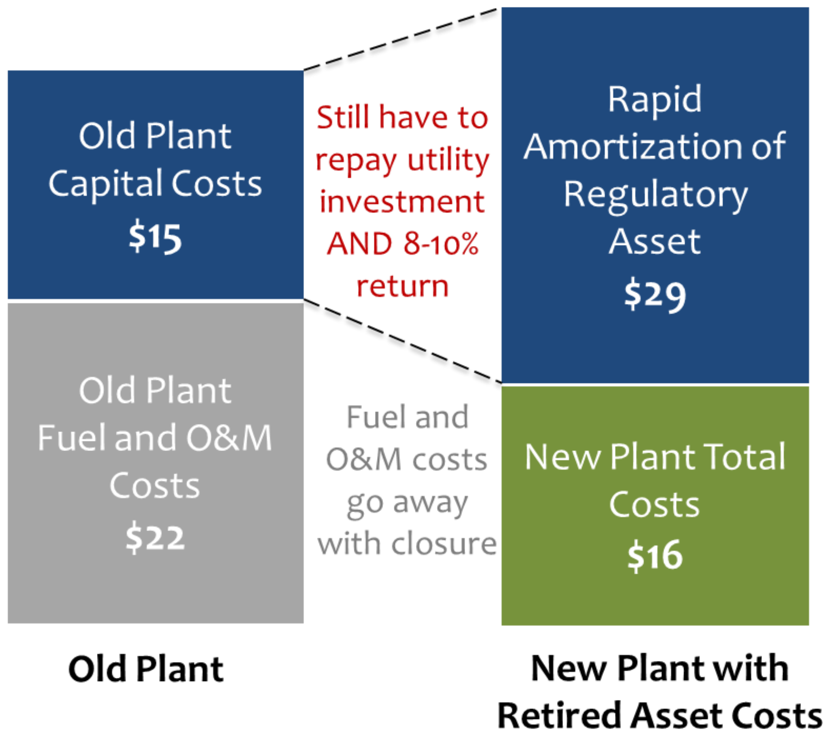


Figure 13: Early retirement with accelerated cost recovery can spike costs, even if the replacement resource is cheaper than just operating the retired asset.

A second barrier has to do with a utility's incentives around early plant retirement in traditional cost-of-service regulation. As a utility's investors earn a regulated rate of return on any unrecovered capital invested in an asset, they are not keen to recover their capital on an expedited schedule. Utility investors generally prefer to keep their invested capital deployed, earning the regulated rate of return – at least, when their allowed return exceeds their cost of capital. Further, if the replacement energy is procured via market purchases and if the costs of procurement are directly recovered through rates, then retirement and replacement result in a reduction in future earnings for the company's equity investors. Thus, utility management is generally not incentivized to consider early retirement as a preferred option.

Q. Are there any financial or regulatory tools that could help with the large outstanding balances in the Company's other generating facilities?

A. Yes. In particular, two of the most uneconomic units – Lansing Unit 4 and Ottumwa – would both benefit from a well-planned retirement that uses financial and regulatory tools to align the interest of ratepayers with that of the utility's investors.

A tool recently used in Michigan and Florida to finance cost recovery for early asset retirement – that has recently been approved for use in addressing early generation asset retirement in Colorado, New Mexico, and Montana – could be a promising approach. Since the early 1990s, over twenty states have passed legislation to encourage their public utility commissions to authorize a financial vehicle for cost recovery known as "ratepayer-backed bond securitization." This financial vehicle can both reduce the cost to ratepayers of early retirement and provide the utility with immediate cost recovery for any remaining net asset balances.

Q. What is the process for securitization?

A. With such appropriate legislative support in place, a public utility commission would execute ratepayer-backed bond securitization by taking the following basic steps:

1. **Set up a company to issue a bond and repay bondholders –** The commission would authorize the formation of a stand-alone company called a special purpose vehicle (SPV) whose sole asset is the rights to a dedicated stream of customer revenues that will be used to pay interest and principal on the bond the SPV issues. The company could be a public benefit corporation set up by the commission (and operated by the utility) as allowed by the authorizing statute or wholly-owned by the utility specifically for this purpose.

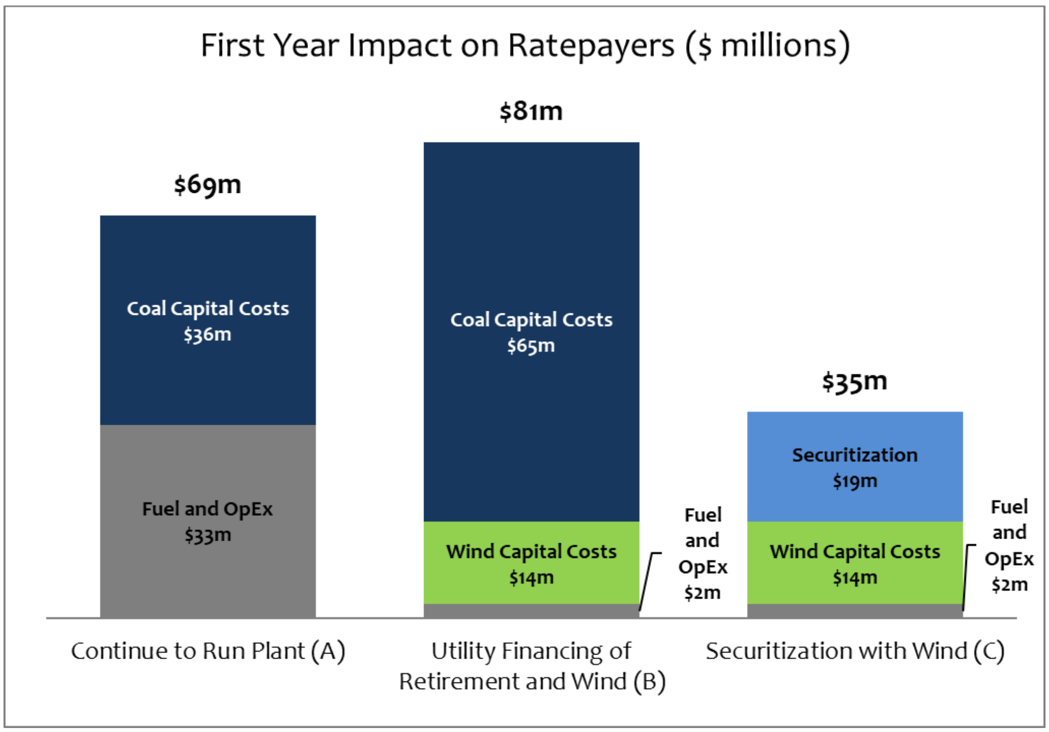
2. **Create a dedicated customer revenue stream to pay bondholders –** The commission would set up a dedicated line item on customer's bills whose sole purpose is to pay interest and principal on the bond issued by the SPV. The amount on the line item must be automatically adjusted each month to meet the required interest and principal payments. The rights to the revenues from this line item would be owned by the SPV.

3. **Issue a long-term (15-30 year) bond whose proceeds are used to provide immediate cost recovery to the utility –** The bond's proceeds are used to provide the utility with immediate cost recovery. For example, if this were done in 2020 for the $350 million in expected unrecovered plant balances and expected decommissioning costs net of salvage expected from the early retirement of Lansing Unit 4, a bond of the same size would be issued by the SPV, and the proceeds immediately transferred to the Company. The SPV and revenue line item can be structured to have no impact (or even a positive impact) on the utility's credit rating.

4. **Pay interest and principal on the bond over 15-30 years through dedicated customer revenues –** The dedicated customer revenues are then used by the SPV to pay interest on the bond and repay principal. Since the interest rate can be quite low, and the principal repaid over 15-30 years, the financing costs of securitization can be much lower than paying off a regulatory asset. Specifically, the credit rating agencies (Moody's, S&P) provide detailed criteria for the structuring of the authorizing legislation, the SPV, the revenue line item, and the bond so as to achieve the highest achievable bond credit rating. In today's low interest rate environment, such a highly-rated (AAA) bond can result in a 15-30 year bond with a yield of 3-4%.

Q. What are the results of using securitization?

A. As a result of this securitization, instead of the customers paying the company nearly 9-12% in authorized financing costs on a pre-tax basis each year on any outstanding unrecovered balances in assets retired early over an extended period of time, they will instead pay a much lower 3-4% interest annually over 15-30 years.



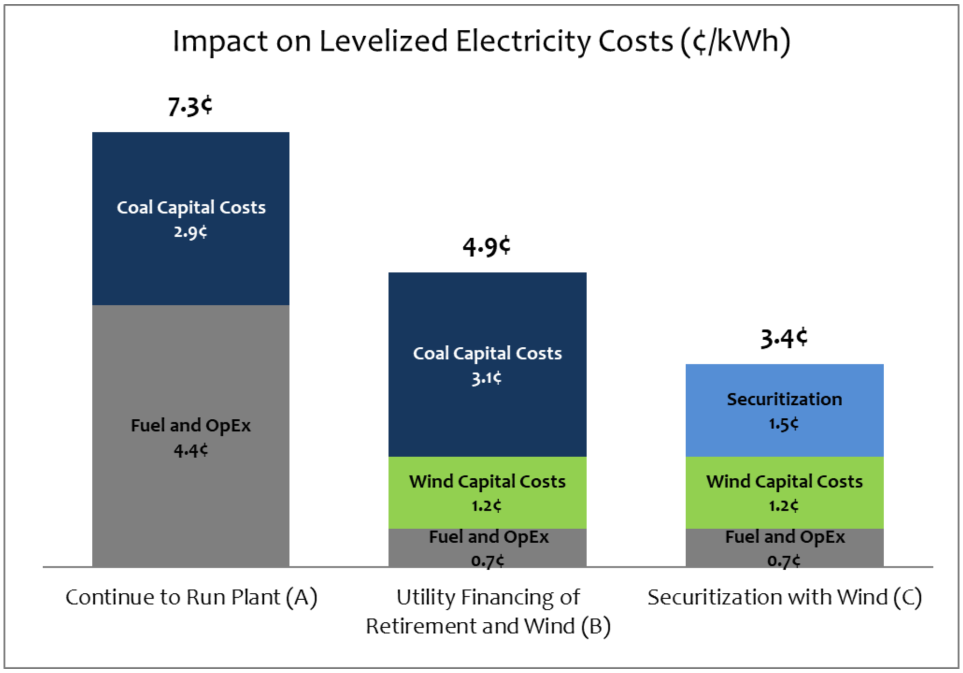


Figure 14: The current and long-term rate impact of Lansing 4 compared to scenarios involving early retirement and replacement with wind.[24]

For IPL, this approach to dealing with the risk of early retirement provides the utility with the flexibility to recycle their invested capital to take advantage of increasingly attractive future clean energy opportunities. That is, it gives them the option to eliminate underperforming assets when they find it economic to do so without losing their invested capital and with significantly reduced ratepayer impacts, thereby allowing them to potentially redeploy that capital (and more) in more economical alternative assets as the opportunity arises. The value of this option could be more attractive on a risk-adjusted basis in its impact on the long-term growth prospects for the Company than the riskier bet they are making around the continued operation of uneconomic facilities. That is,

[24] RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018.

securitization with capital recycling into new wind by the utility could be a win-win-win for customers, IPL, and the environment.

Q. How does securitization compare with accelerated depreciation for the Company's generators? Does is make sense here?

A. We have attached the results of a detailed analysis of the ratepayer and utility earnings impacts of each of the eight generating facilities as Appendix A to this testimony. As an example of how securitization could work for the Company, consider the potential early retirement of Lansing Unit 4. If accelerated cost recovery is implemented, as shown in Figure 14 above, early retirement and accelerated depreciation could increase rates by $12 million in the first year alone. If accelerated cost recovery is not required – or a refinancing tool like securitization is used – these hypothetical increases could be avoided, instead providing near term cost savings of $34 million from early plant retirement and replacement. And for the utility, securitization paired with the potential upside of ownership of the replacement generating facility could boost future earnings by over 30%. See Figure 15 below.

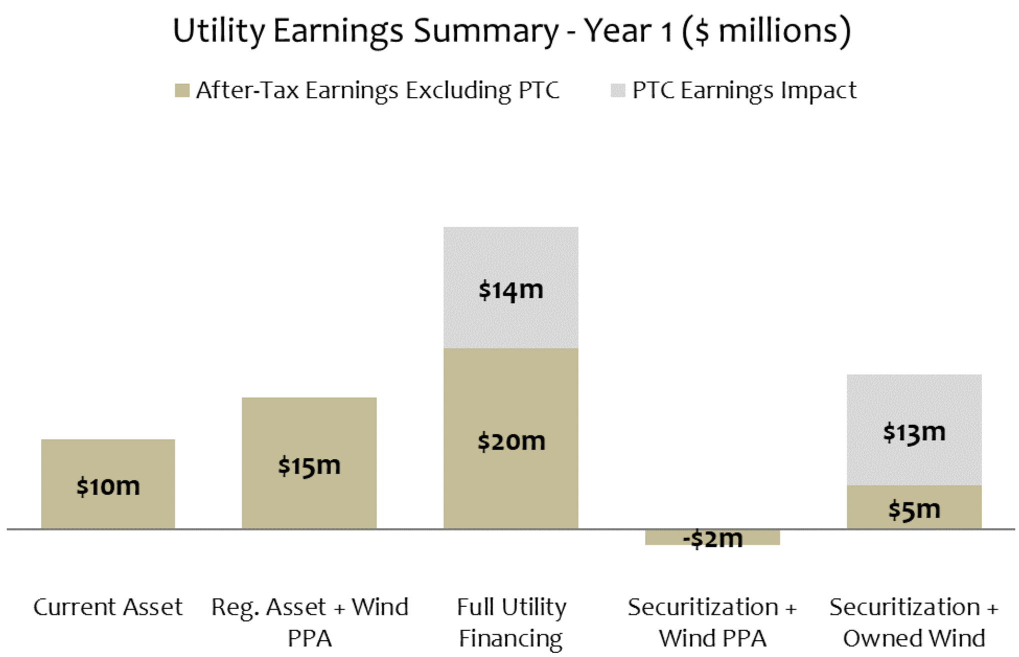


Figure 15: Utility earnings impacts for early retirement and replacement of Lansing Unit 4.[25]

The use of securitization, in particular, paired with allowing the utility to invest in replacement wind, can reduce electricity costs for ratepayers not only today but also into the future. See Figure 14 above.

We see similar results for all the other large generating assets, as shown in Appendix A of my testimony.[26]

Q. What are the limits and challenges with using securitization?

A. There are several challenges that are worth mentioning. First, securitization needs to be enabled by legislation – as it has been in the other states that the tool has been used. Therefore, it is not currently available for use in the state of Iowa. However, securitization can be used after a retirement decision is made to refinance regulatory

[25] RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018.
[26] Input assumptions for each plant are also provided for reference in Appendix B.

assets remaining after early retirement, even retrospectively. Therefore, if a retirement decision is made today, the option remains open for legislators and the Board to use the tool in the future to mitigate the costs of that decision.

Further, securitization is just an example of a mechanism to refinance cost recovery with lower-cost bonds. It is possible that such a refinancing could be accomplished without legislative authority and through corporate bond financing. However, I am not aware of any precedent for the use of such an approach so far to deal with cost recovery.

Second, we note that securitization does have limits. While Moody's, S&P, and Fitch's general guidance on securitization suggests that the tool is credit neutral or mildly credit positive for most utilities, that assessment has limits. As a rule of thumb, the tool generally cannot result in securitization charges that exceed roughly 20% of total bills before leading to negative credit implications.

Q. What options besides securitization can be implemented now?

A. While securitization still likely represents the most economic option to address cost recovery, there are other financial and regulatory tools that can address this issue and reduce ratepayer costs and risks while aligning the Company's interests with that of transitioning its assets more rapidly to reflect cleaner, cheaper generation options that could result in cost savings for both current and future ratepayers.

State regulators across the country have applied a number of financial and regulatory tools to address cost recovery in early retirement, with varying impacts on the utility and ratepayers in the short and long term. These tools include disallowance of some or all the costs for uneconomic plants, reduction in the allowed return on unrecovered costs for assets retired early (ranging from debt cost to the weighted average cost of capital, or WACC), accelerated cost recovery, and full cost recovery without acceleration.

As described in Figure 16 below, each of these tools has drawbacks for customers, and in the absence of any opportunity for a utility to reinvest its capital, is generally unattractive for the utility – with the exception of full utility cost recovery without acceleration. For example, a reduction in the allowed return for costs remaining to be recovered after early plant retirement can help mitigate near-term rate impacts for customers. However, for the utility's equity investors, the presence of a long-term asset on the utility's balance sheet with a return too low to provide earnings commensurate with the cost of their equity capital is unattractive – and for their debt investors, the reduced cash flows mean reduced margins of safety on debt repayments. This, in turn, can result in lower potential future credit ratings, and a higher long-term cost of capital that can negatively impact future ratepayers.

However, as shown in the second chart in Figure 16, if some of these tools are accompanied by "capital recycling," allowing the utility to reinvest its capital or otherwise replenish the future cash flows or earnings lost to the utility as a result of early retirement, some of these options become more attractive. For the above example of a reduced allowed return, the potential negative credit and future ratepayer impacts are alleviated if the utility can reinvest recovered capital and replenish its earnings and cash flows over time.

Further, the use of any one of these tools would not preclude the future use of securitization if the Iowa legislature chooses to make it available to the Board.

Q. Is the consideration of financial tools similar to securitization consistent with legislative direction and prior decision-making by the Board?

A. I would point to the following guidance from the general assembly, indicating that the utility board will not *"be limited to traditional ratemaking principles or traditional recovery mechanisms*."[27] Furthermore, the code stresses that the board may seek these alternative recovery mechanisms to provide "reasonable restrictions upon the ability of the public utility to seek a general increase in electric rates." [28]

This opens the door for alternative refinancing mechanisms like securitization and for the commission to explore disallowance – especially in situations where those mechanisms can be shown to prevent customer rate increases or to actually decrease those rates over time.

In its final Decision and Order in MidAmerican's Wind XII Docket, the Board has indicated an openness to the possibility of disallowing some or all asset-related costs it deems as "imprudent and unreasonable" "should a rate-regulated utility continue to utilize an uneconomic facility."[29]

Given that the utility is operating coal assets that are not reasonable and prudent investments and given that the ensuing high operational and fuel costs are being completely borne by the ratepayer – the Board should pursue a method to share the risk burden for those costs or disallow them completely.

[27] IOWA CODE § 476.53(3a)"2"(b) (2019).
[28] *Id.*
[29] IUB Docket No. RPU-2018-0003, Final Decision & Order, Page 34.

	Impacts on UTILITY		Impacts on CUSTOMER	
NO Capital Recycling	Credit	Equity	Short-Term	Long-Term
Disallowance (from 0-100%)	XX	XX	✓✓	--
Vary Allowed Return (from Debt Only to WACC)	X	X	✓	--
Accelerate Depreciation (to 4-10 Years)	--	--	XX	--
Full Utility Finance (Full WACC, No Accel)	✓	✓	X	X
Securitization	--	X	✓	✓

	Impacts on UTILITY		Impacts on CUSTOMER	
with Capital Recycling	Credit	Equity	Short-Term	Long-Term
Disallowance (from 0-100%)	X	X	✓✓	--
Vary Allowed Return (from Debt Only to WACC)	--	--	✓	--
Accelerate Depreciation (to 4-10 Years)	✓	✓	XX	--
Full Utility Finance (Full WACC, No Accel)	✓✓	✓✓	X	X
Securitization	✓	✓	✓	✓

Figure 16: The impacts of various options for addressing cost recovery compared, both with and without capital reinvestment (“capital recycling”). The **“X” and “XX” in Figure 16 above indicate negative consequences, while check marks and double checkmarks indicate potential positive consequences.**

Q. What else should the Board consider doing?

A. In other jurisdictions, risk-sharing mechanisms exist wherein utilities may be mandated to sell some or all of their power into wholesale markets and purchase replacement power to cover demand. By invoking a risk-sharing mechanism, the utilities bear a portion of the risk associated with selling (potentially more expensive) power into the market and purchasing replacement power at a loss, incentivizing them to lower the generating costs of existing assets to reduce this loss.

In order to incorporate market signals into utility operations, the Board should consider establishing a risk-sharing mechanism. In this scenario, the utility only passes on a portion of its losses from selling uneconomic power into the market and must internalize the remainder. This has the benefit of incentivizing the utility to strive to lower its operating costs to minimize these losses, which also lowers costs for ratepayers.

Q. What do you recommend that the Board do at this time?

A. My analysis has shown that three of IPL's units could be retired with accelerated cost recovery and replaced with sufficient wind generation to replace the full value of the grid services they provide, while still achieving $16 million in savings in rates in the 2020 test year.

As a result, I recommend that the Board move forward immediately with disallowing the operating costs of Neal 3, Neal 4, and Burlington in rates and instruct IPL to move forward with retiring those plants early, recovering their costs using ten-year accelerated cost recovery.

I also recommend that the Board instruct IPL to build on its plan to acquire 1000MW of wind by soliciting for additional cost-effective, clean generation (particularly wind with full or partial production tax credits, and solar and storage while their investment tax credits are still available) that could cost-effectively replace the services provided by these assets.

Further, I recommend that the Board require IPL to explore accelerating its acquisition of additional wind (as well as solar power and storage) to take maximal advantage of expiring federal tax credits to reduce ratepayers costs by:

1) fully replacing the services that Neal 3, Neal 4, and Burlington currently provide, and
2) reducing IPL's reliance on the uneconomic energy and grid services provided by IPL's other large coal units (Lousia, Lansing 4 and Ottumwa) and combined-cycle gas unity (Emery and MGS).

Q. What else should the Board consider doing?

A. Finally, for the remaining five units, the board should consider exploring alternative approaches to refinancing cost recovery akin to securitization. While securitization is likely the most efficient tool to use to address cost recovery, there are other mechanisms that can be deployed, both with and without the option of allowing the utility the opportunity to reinvest any capital recovered.

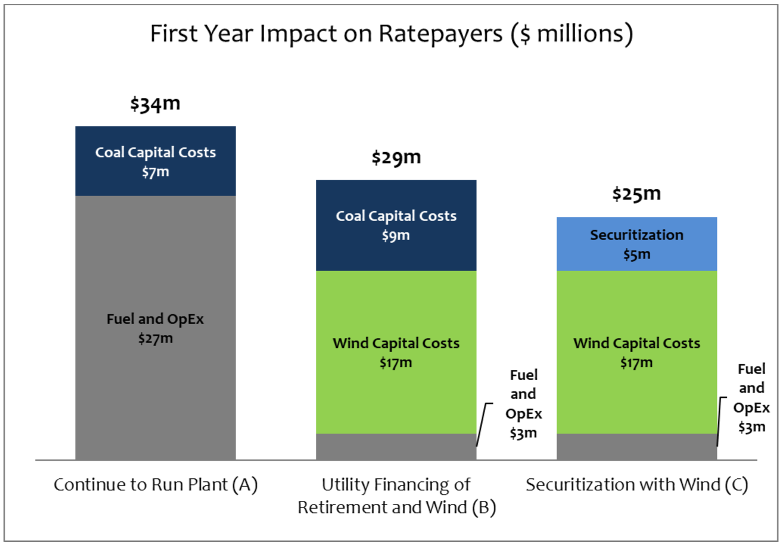
Q. Does this conclude your testimony?

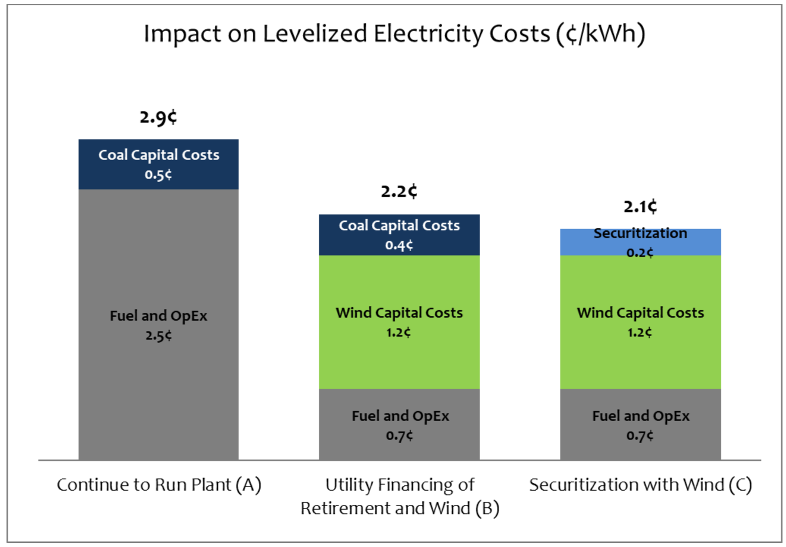
A. Yes.

APPENDIX A

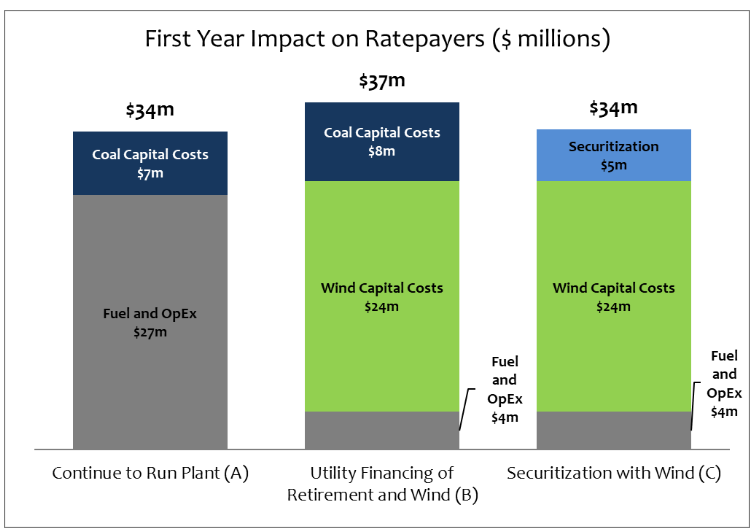
Burlington Station

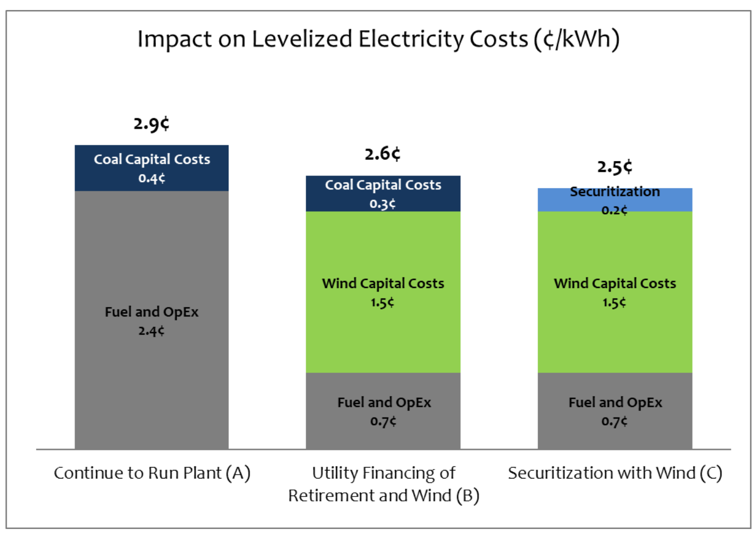
Effect on Revenue Requirement and LCOE – Full PTC



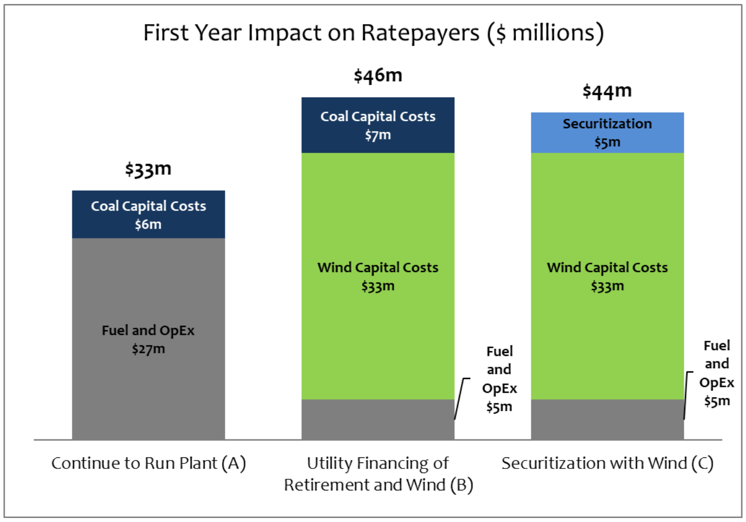


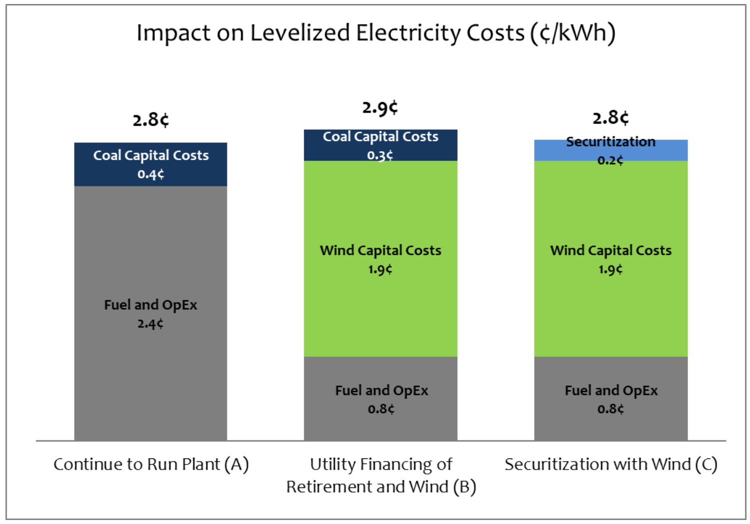
Effect on Revenue Requirement and LCOE – 80% PTC



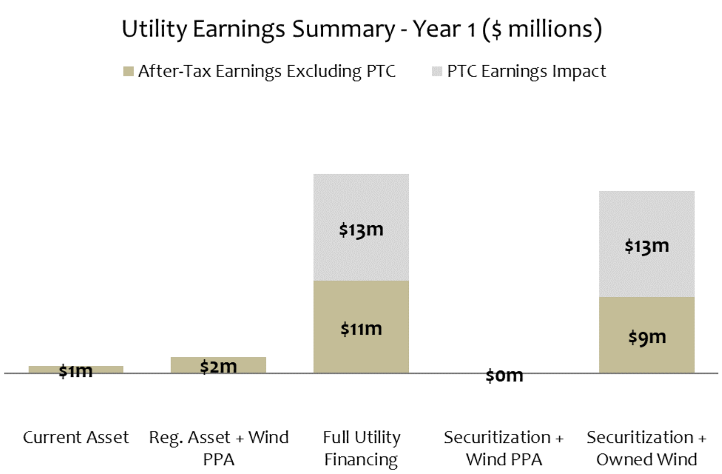


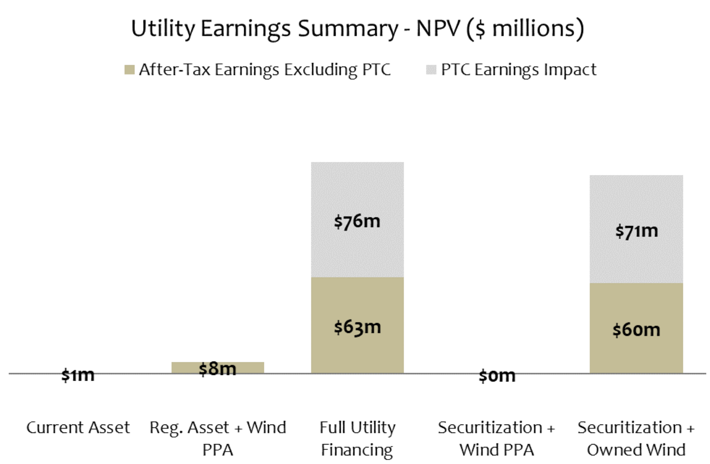
Effect on Revenue Requirement and LCOE – 60% PTC





Effect on Utility Earnings – 80% PTC

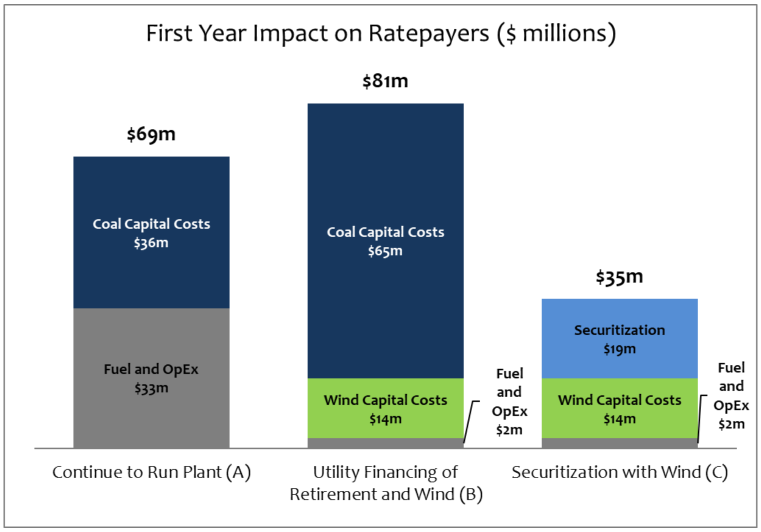


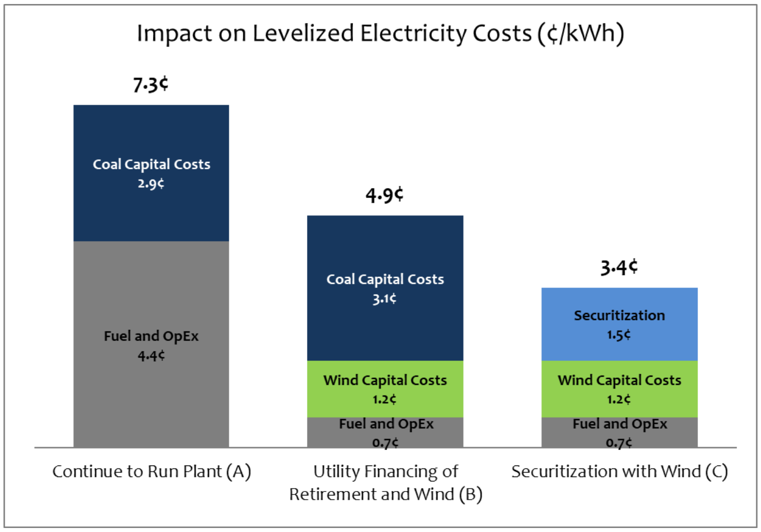


Source: RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018.

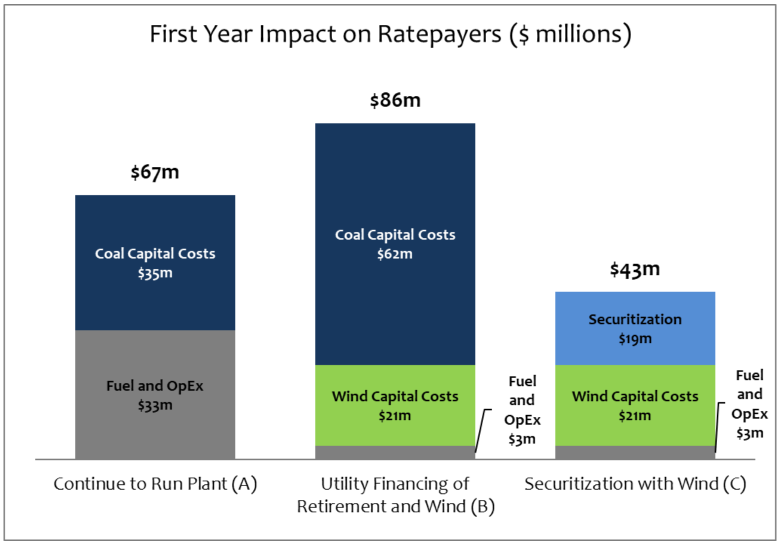
Lansing Unit 4

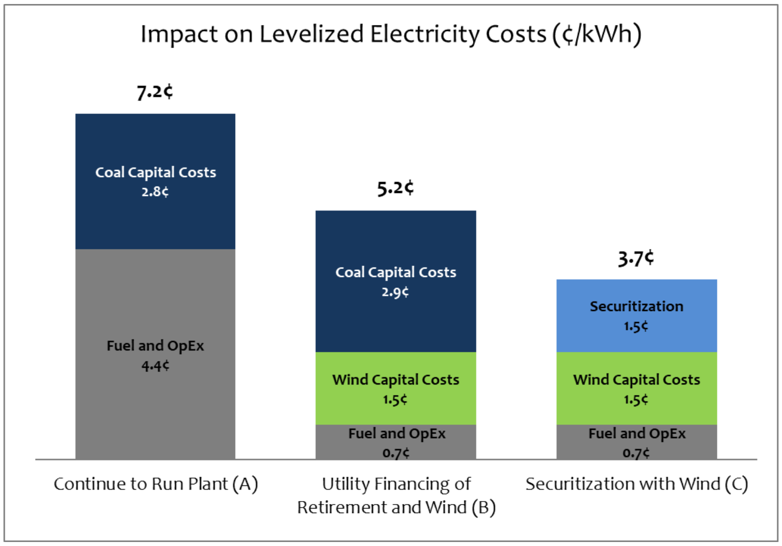
Effect on Revenue Requirement and LCOE – Full PTC



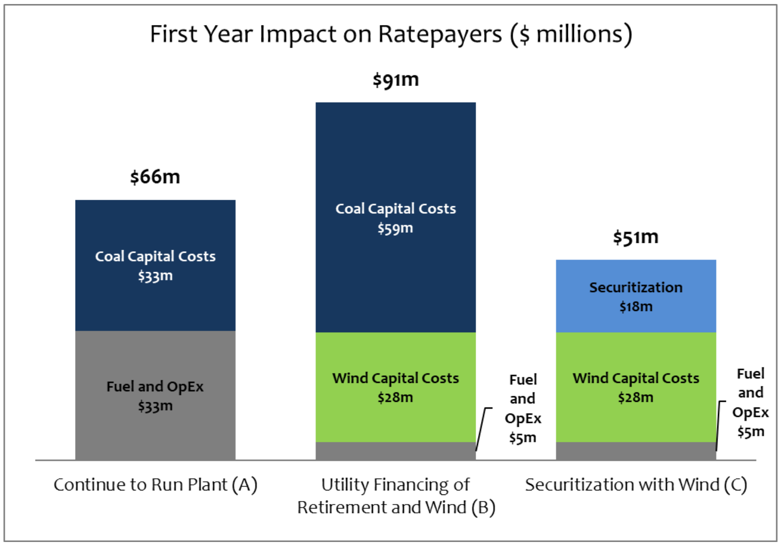


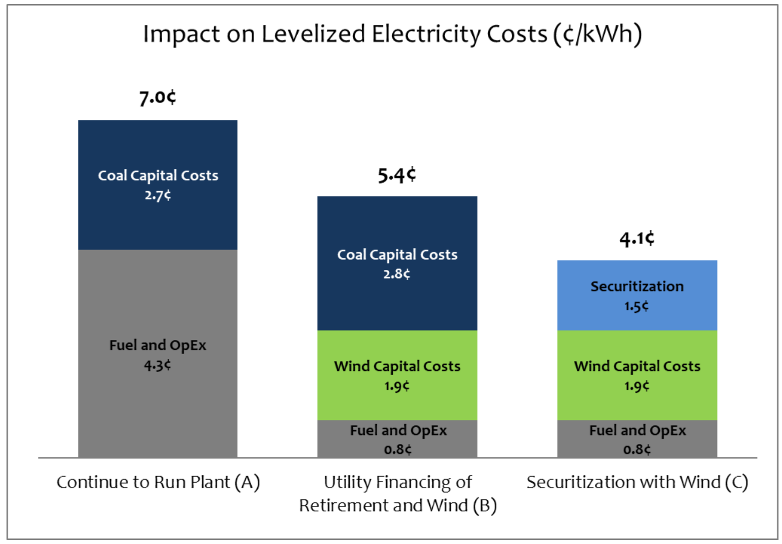
Effect on Revenue Requirement and LCOE – 80% PTC



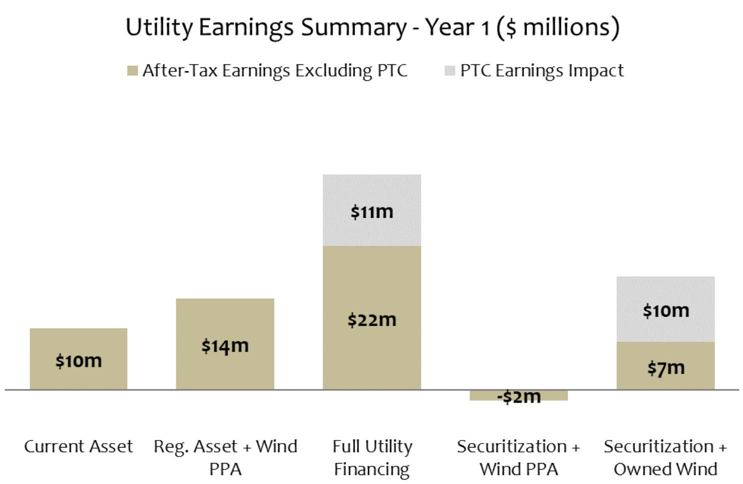


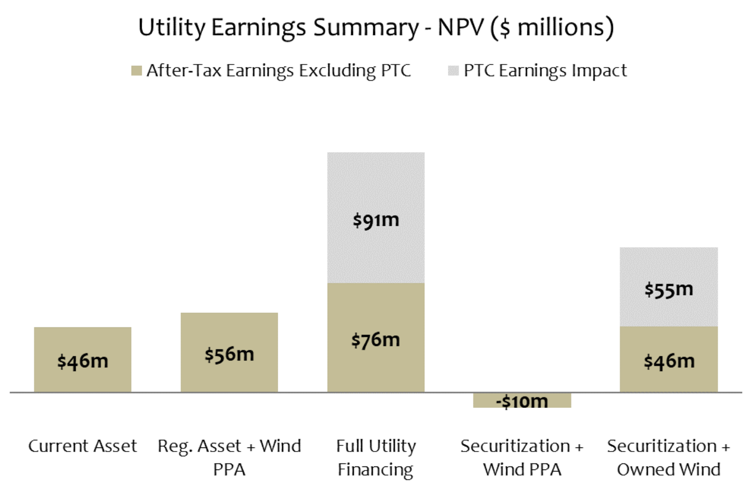
Effect on Revenue Requirement and LCOE – 60% PTC





Effect on Utility Earnings – 80% PTC

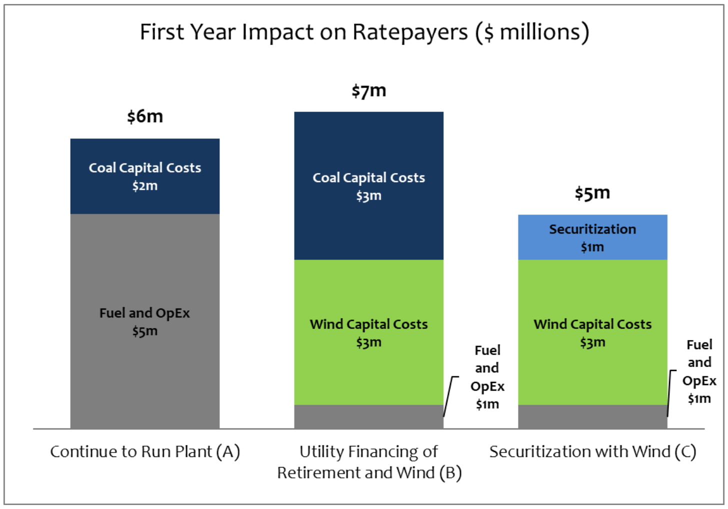


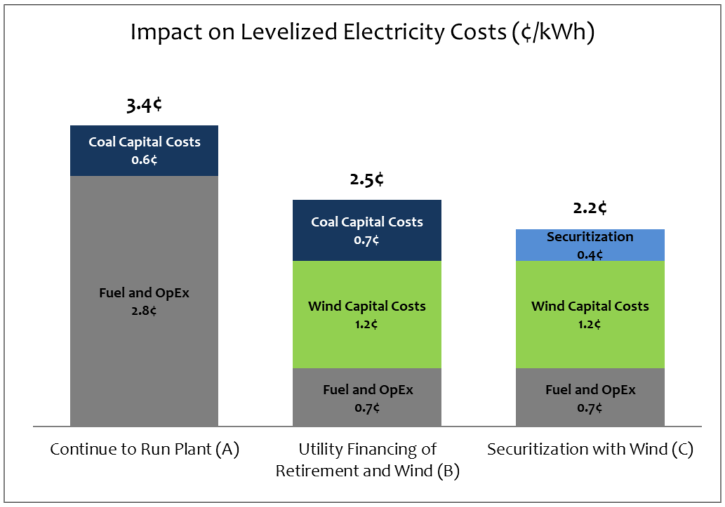


Source: RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018.

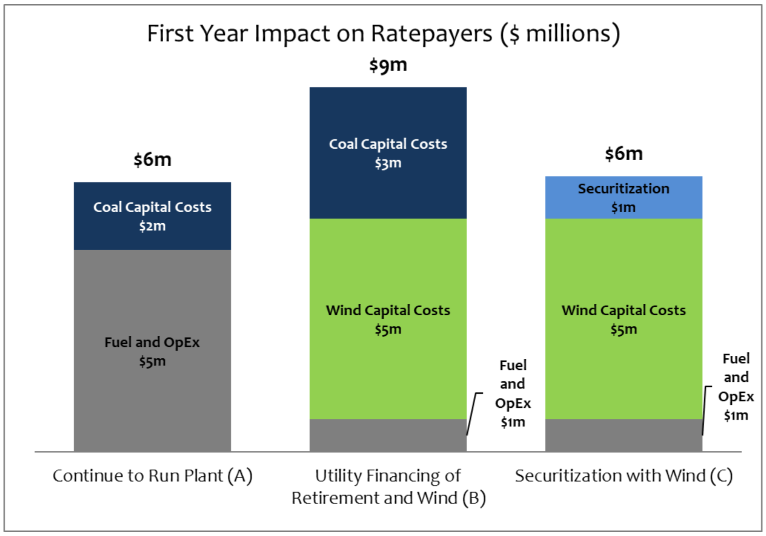
Louisa (IPL)

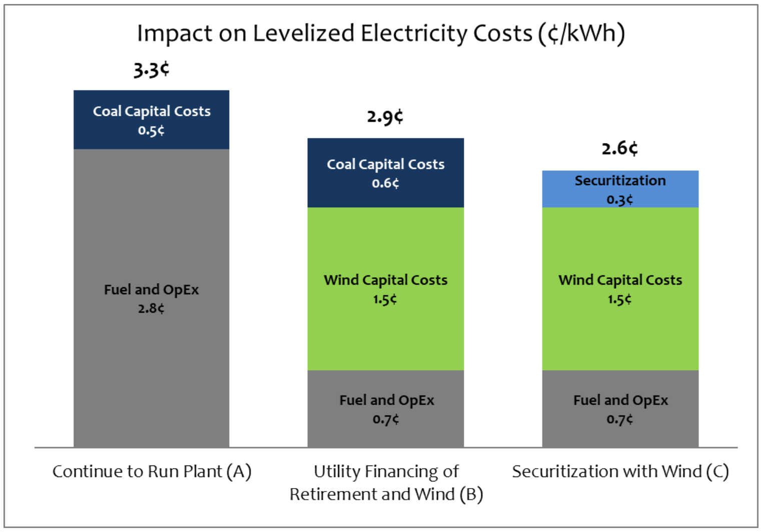
Effect on Revenue Requirement and LCOE – Full PTC



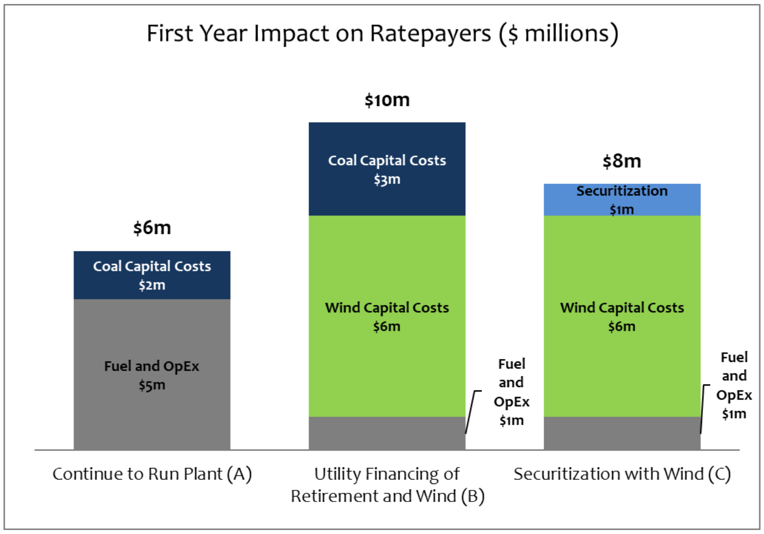


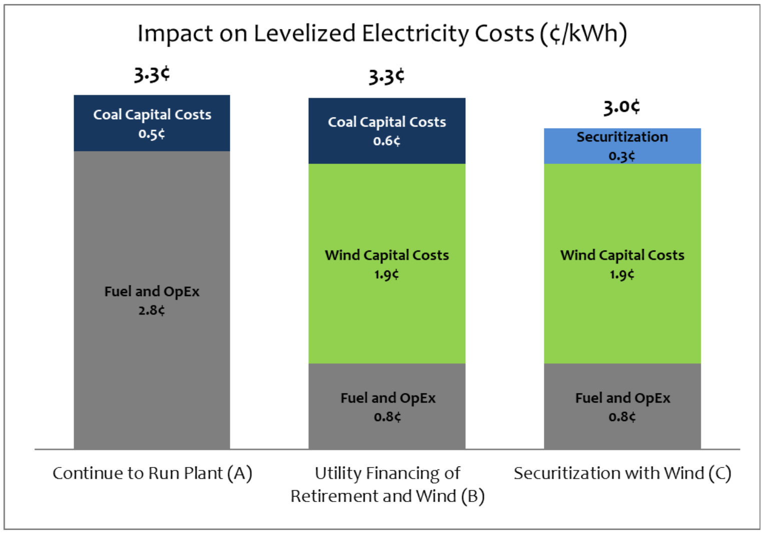
Effect on Revenue Requirement and LCOE – 80% PTC



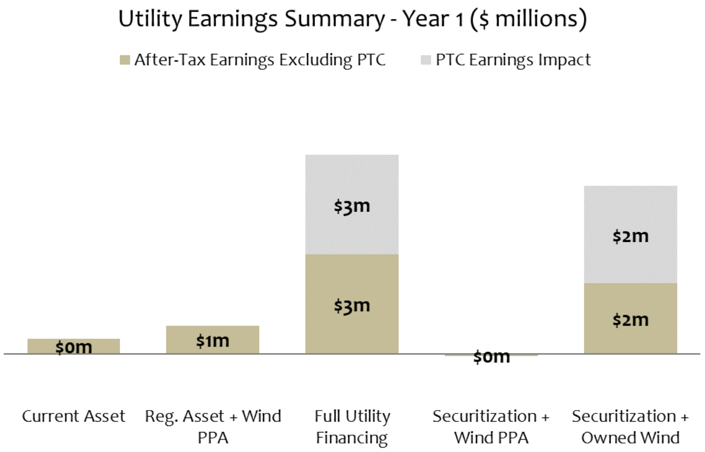


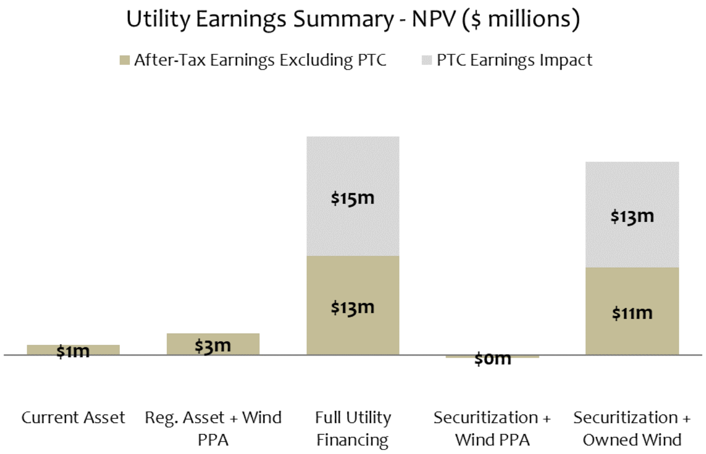
Effect on Revenue Requirement and LCOE – 60% PTC





Effect on Utility Earnings – 80% PTC

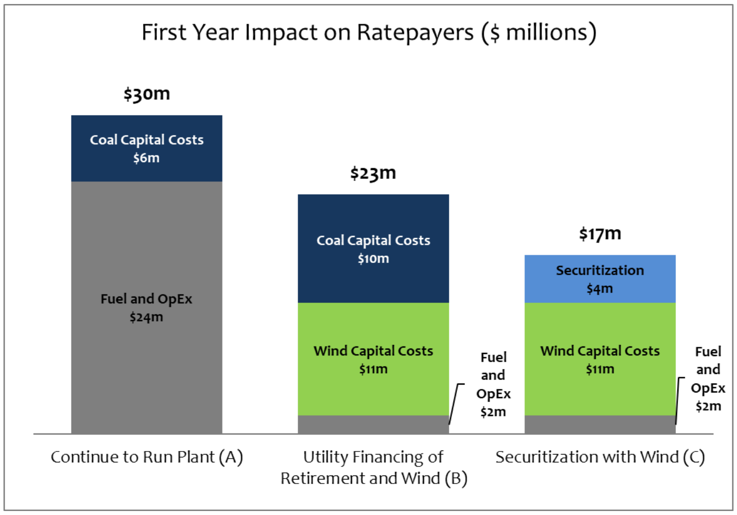


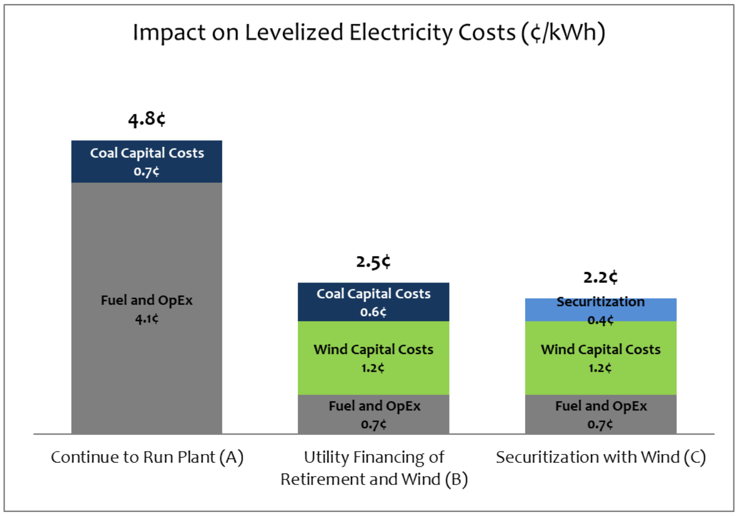


Source: RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018.

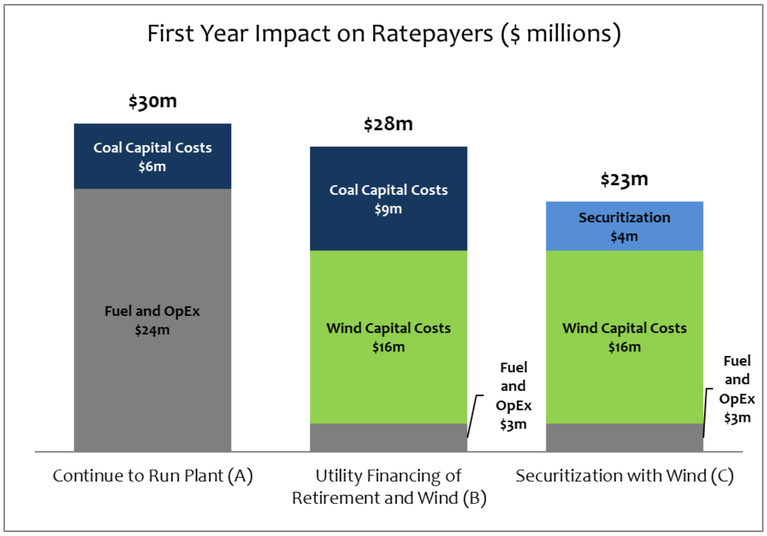
Neal Station 3

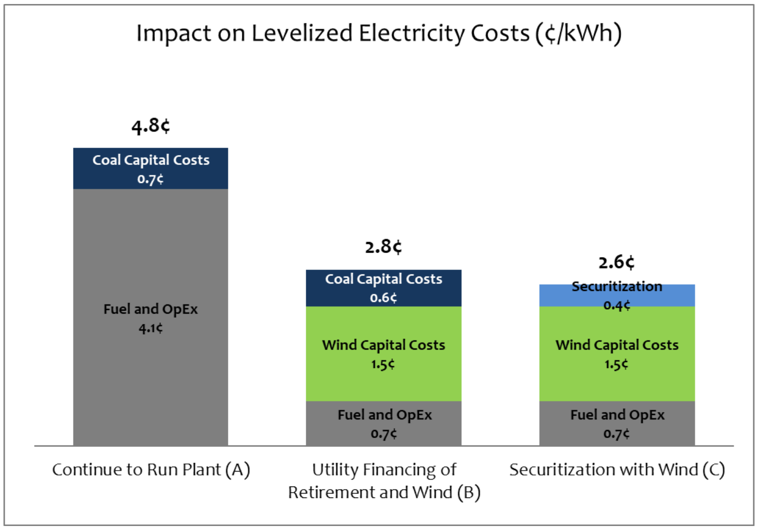
Effect on Revenue Requirement and LCOE – Full PTC



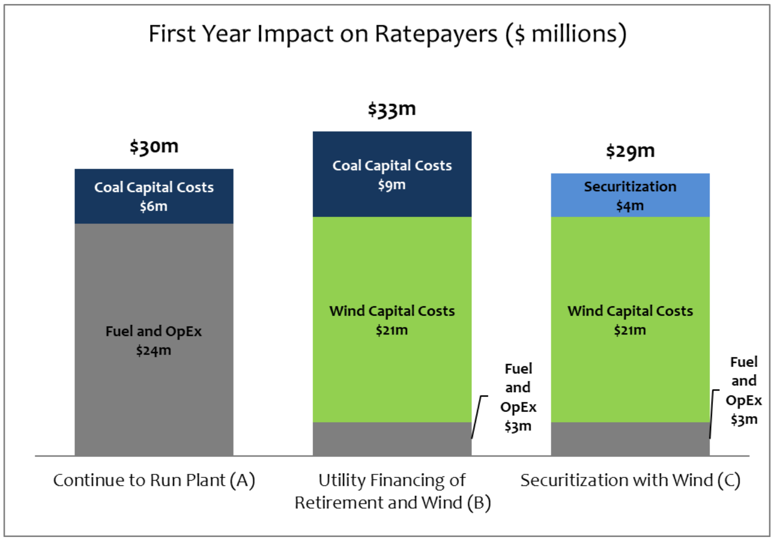


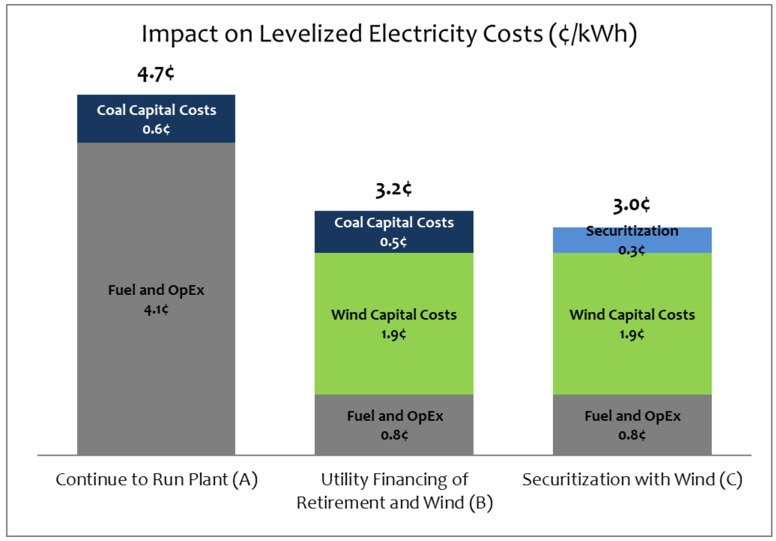
Effect on Revenue Requirement and LCOE – 80% PTC



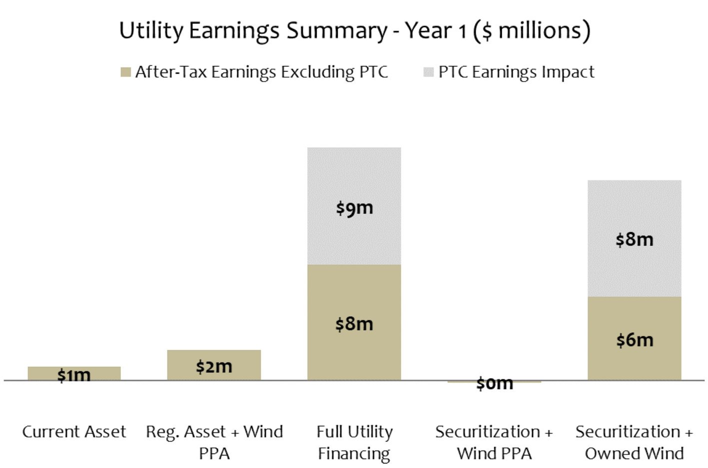


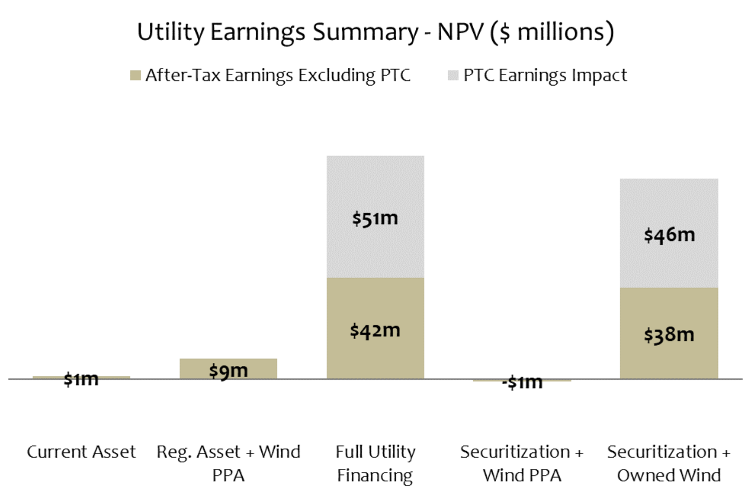
Effect on Revenue Requirement and LCOE – 60% PTC





Effect on Utility Earnings – 80% PTC

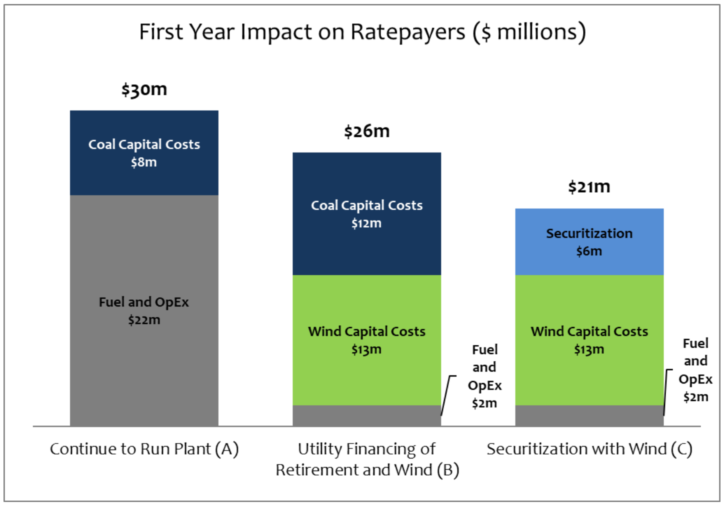


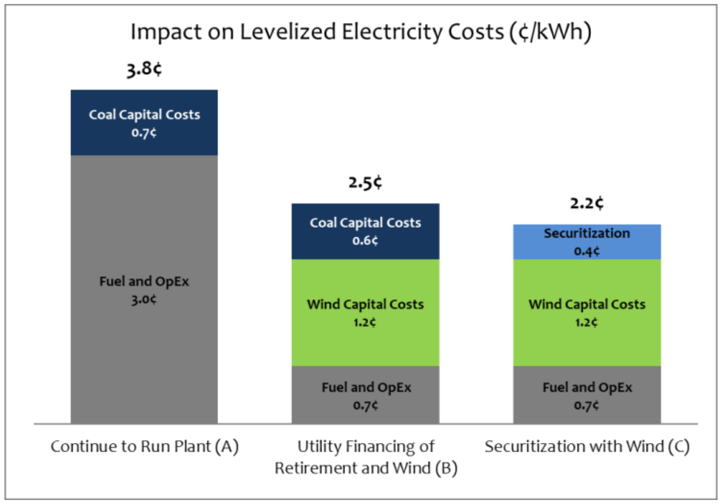


Source: RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018.

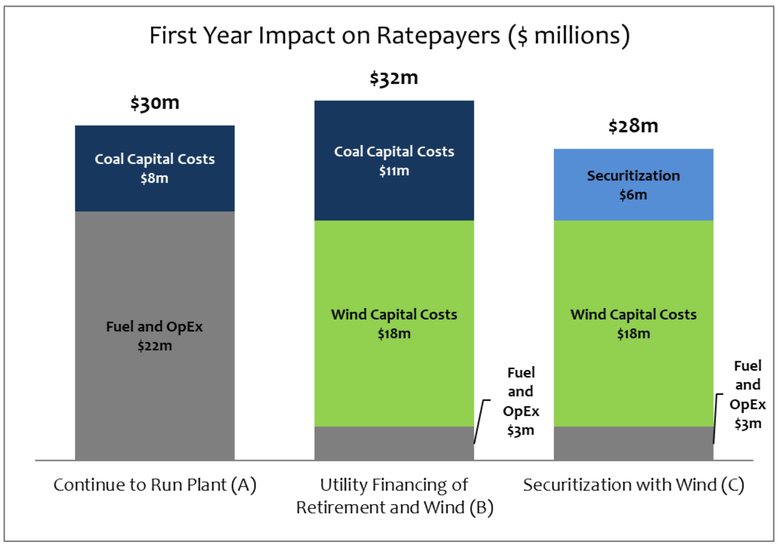
Neal Station 4

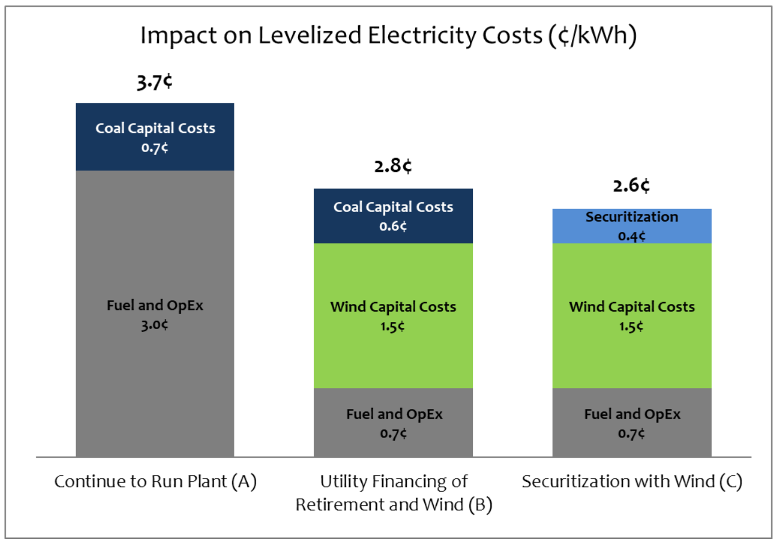
Effect on Revenue Requirement and LCOE – Full PTC



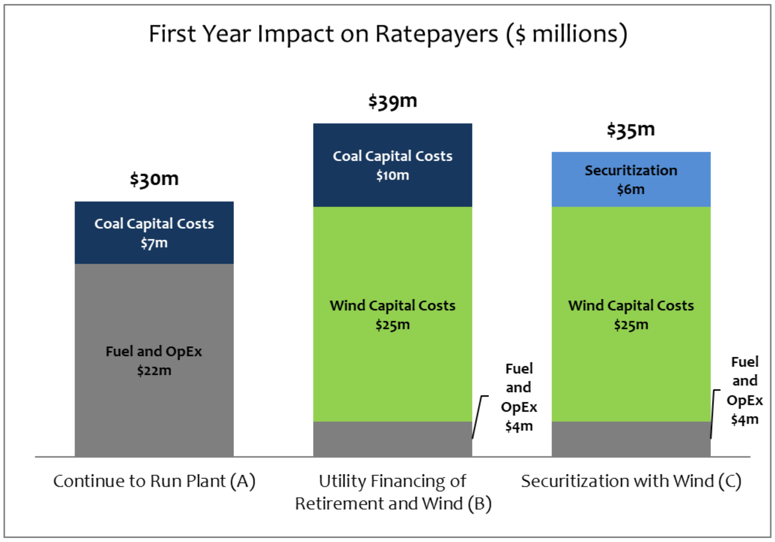


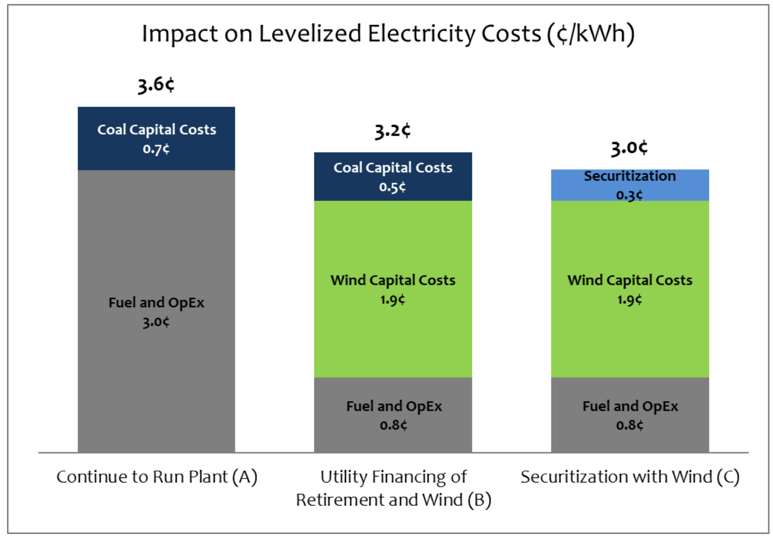
Effect on Revenue Requirement and LCOE – 80% PTC



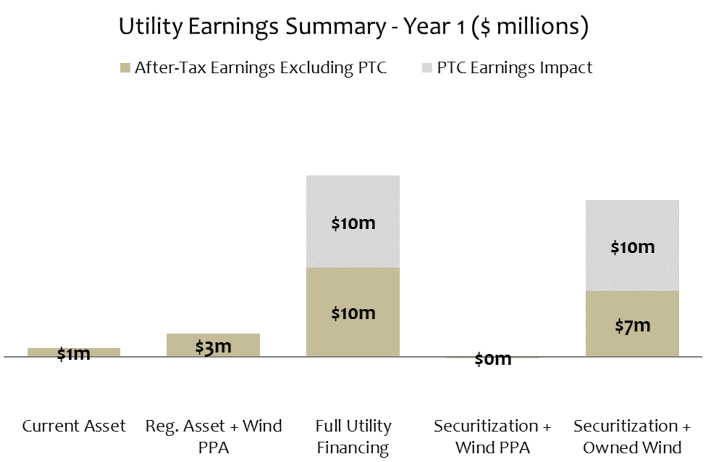


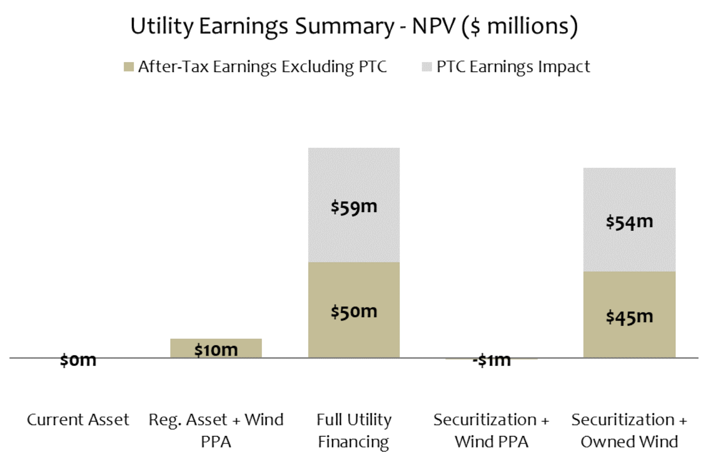
Effect on Revenue Requirement and LCOE – 60% PTC





Effect on Utility Earnings – 80% PTC

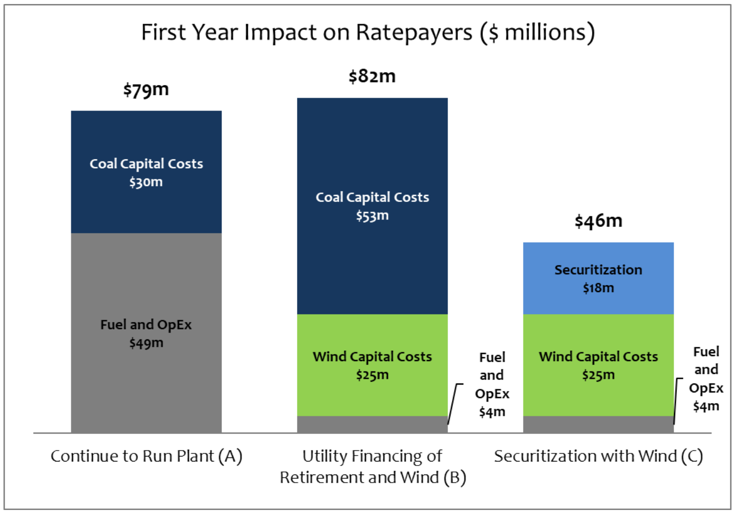


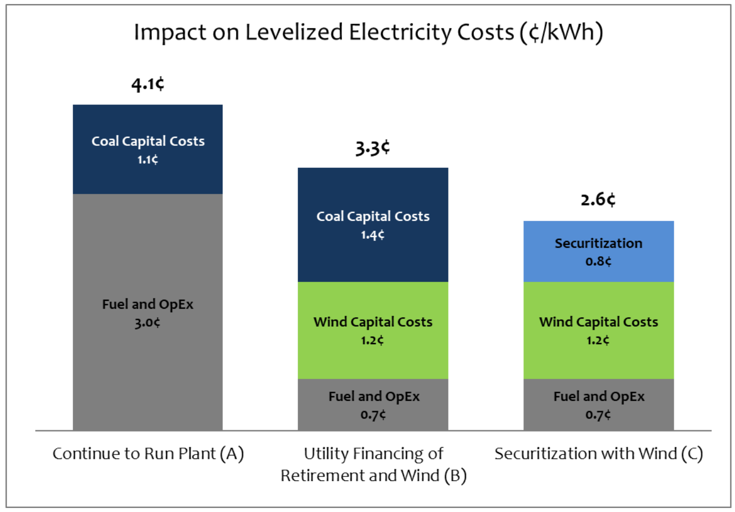


Source: RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018.

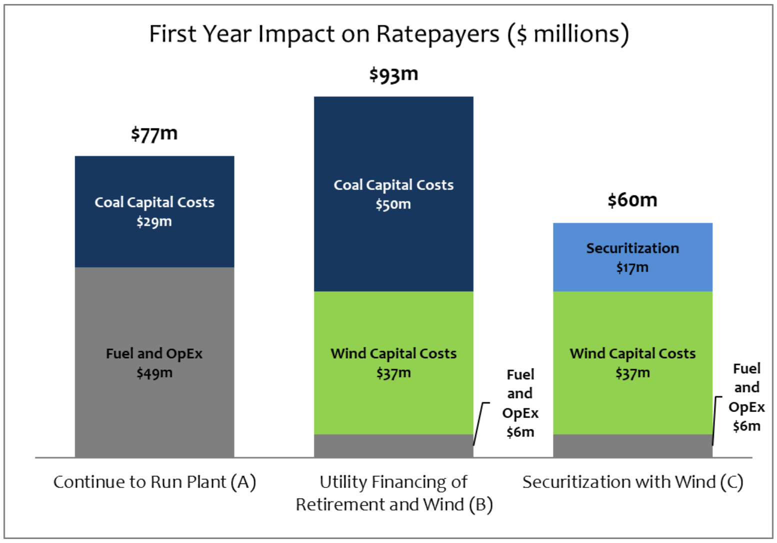
Ottumwa (IPL)

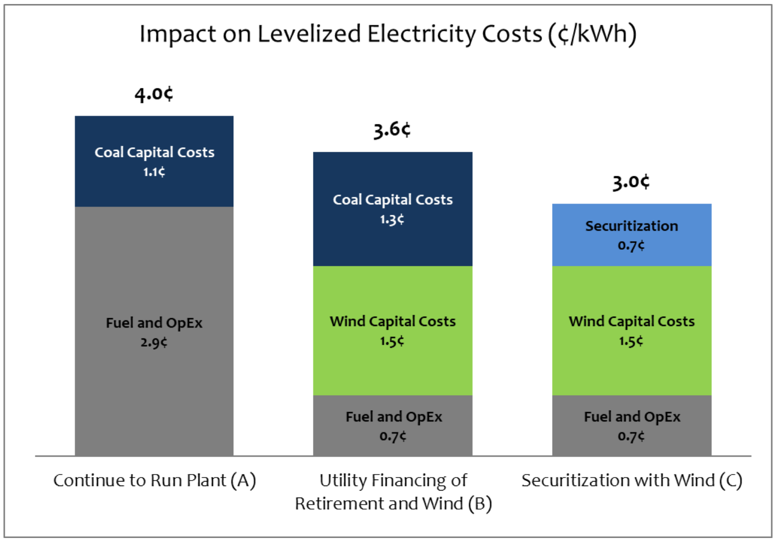
Effect on Revenue Requirement and LCOE – Full PTC



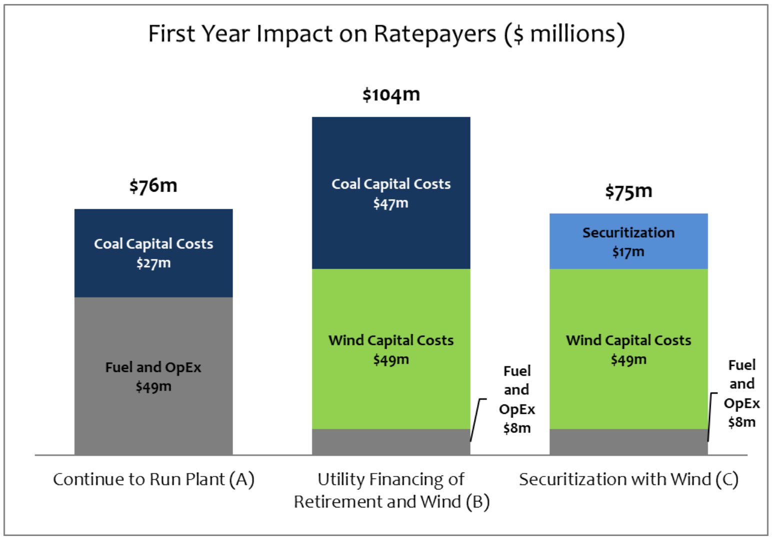


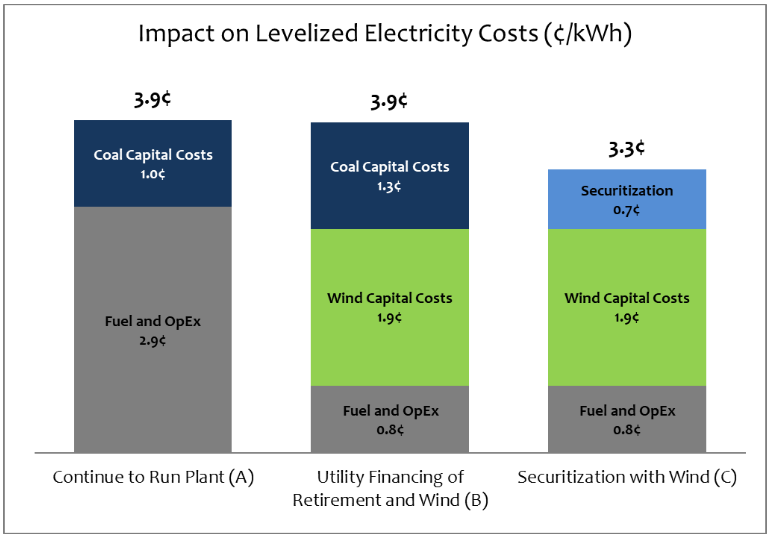
Effect on Revenue Requirement and LCOE – 80% PTC



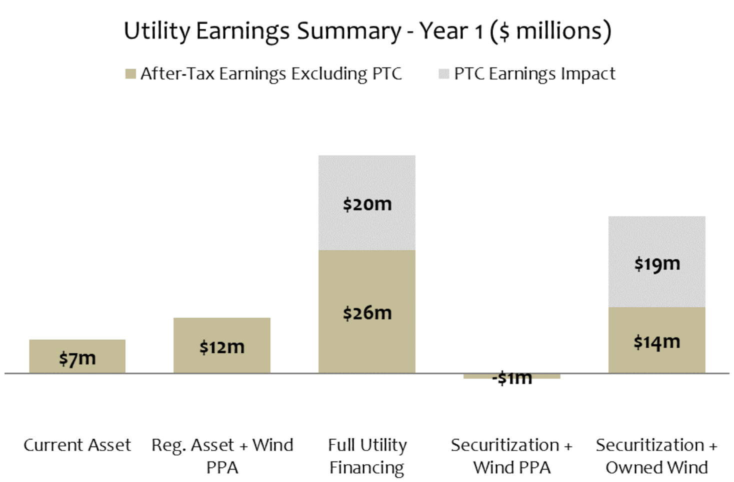


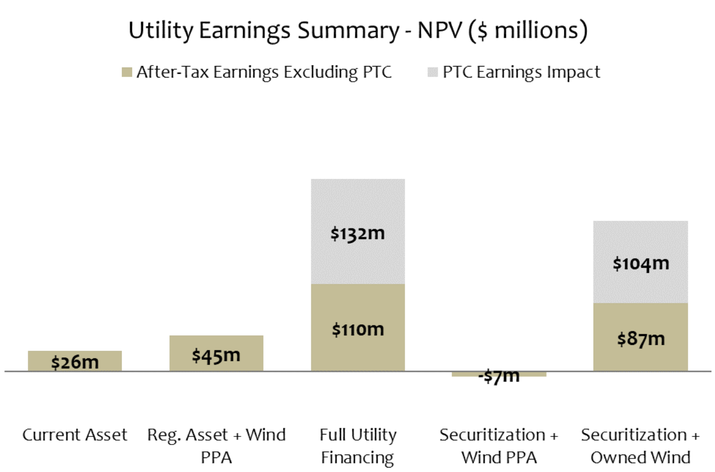
Effect on Revenue Requirement and LCOE – 60% PTC





Effect on Utility Earnings – 80% PTC

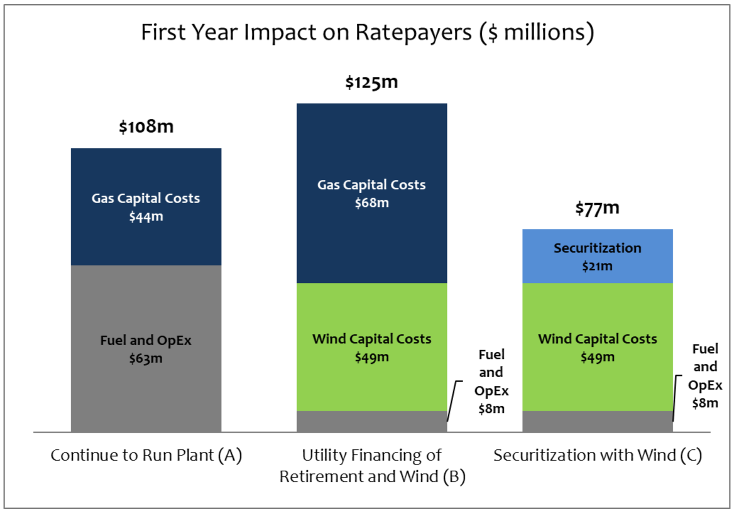


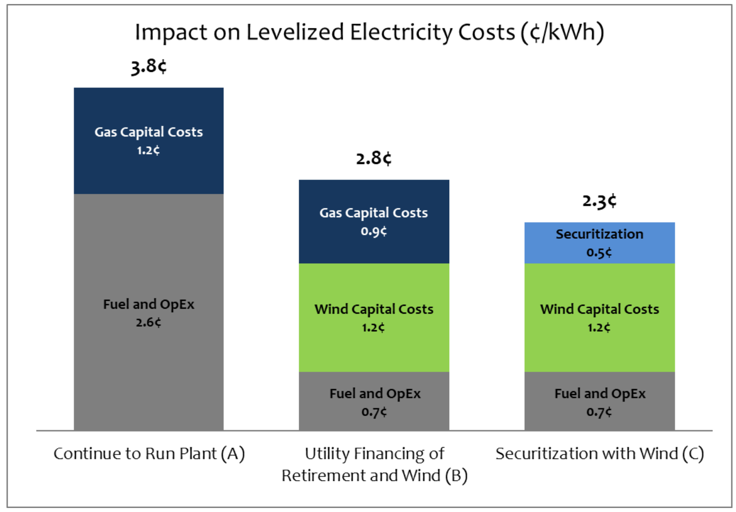


Source: RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018.

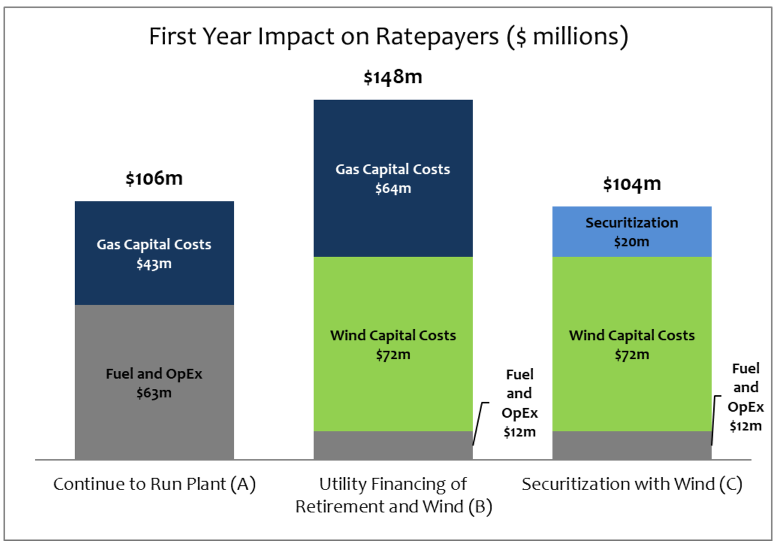
Emery (IPL)

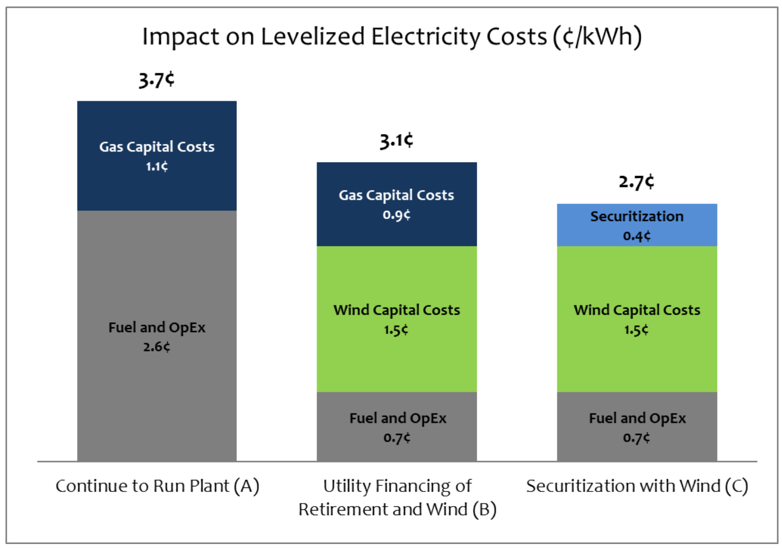
Effect on Revenue Requirement and LCOE – Full PTC



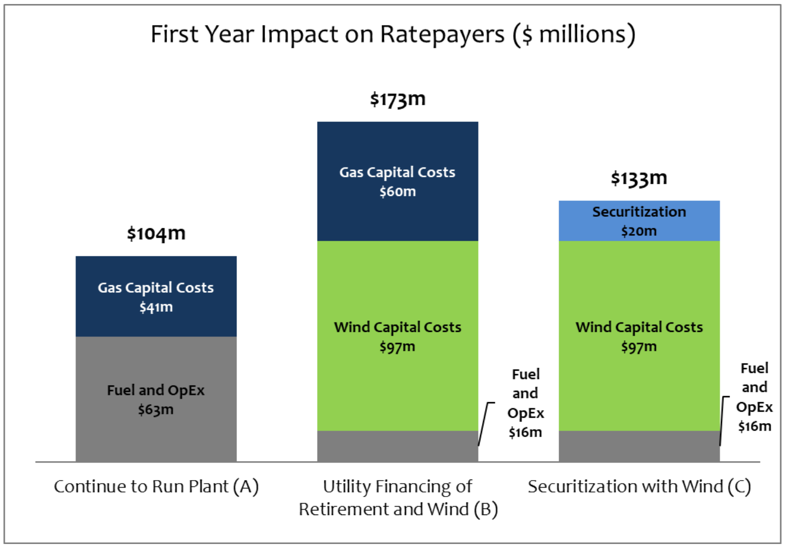


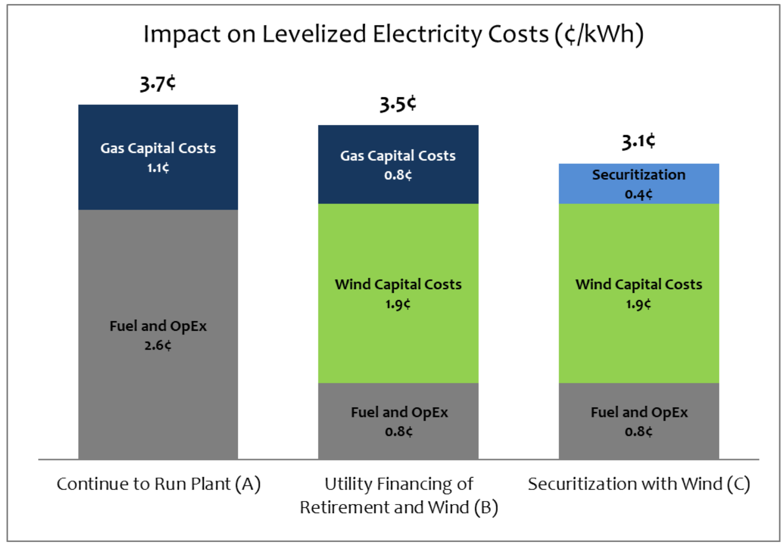
Effect on Revenue Requirement and LCOE – 80% PTC



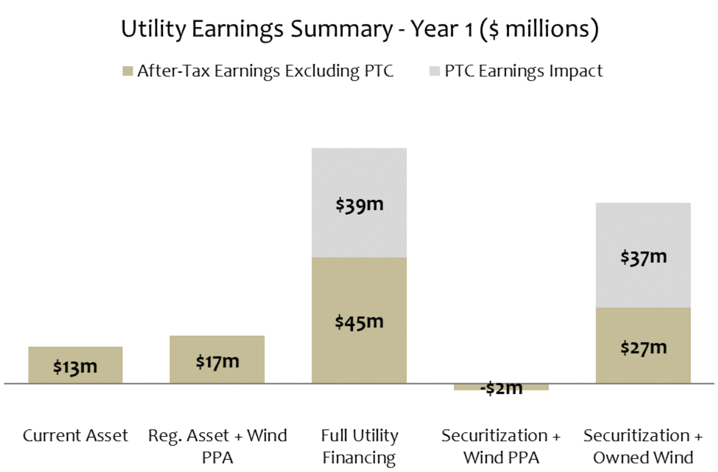


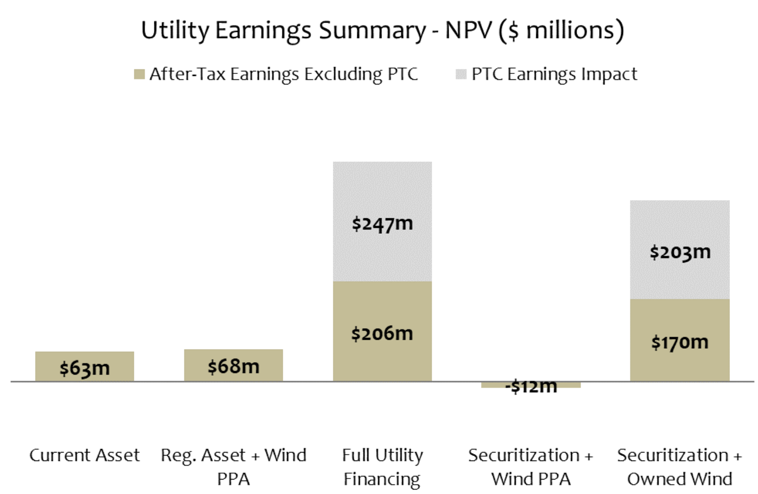
Effect on Revenue Requirement and LCOE – 60% PTC





Effect on Utility Earnings – 80% PTC

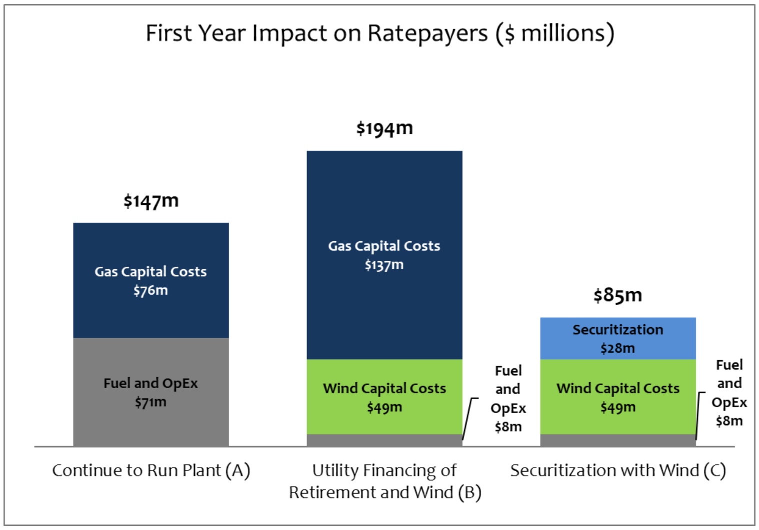


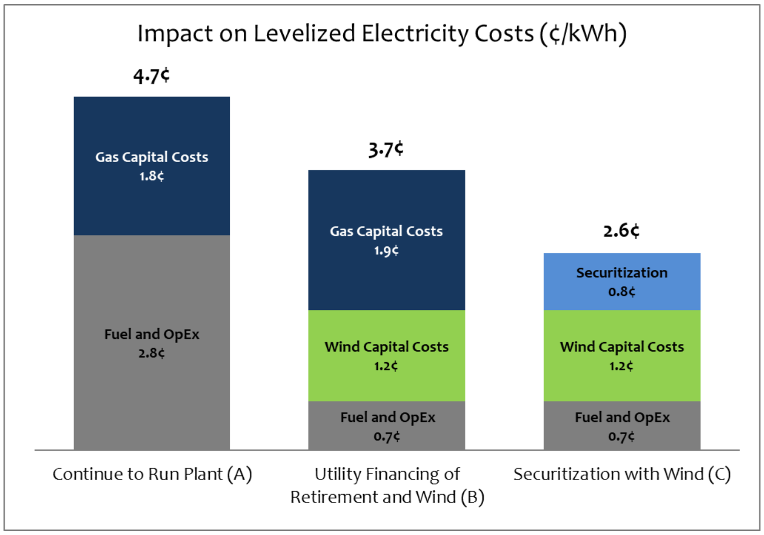


Source: RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018.

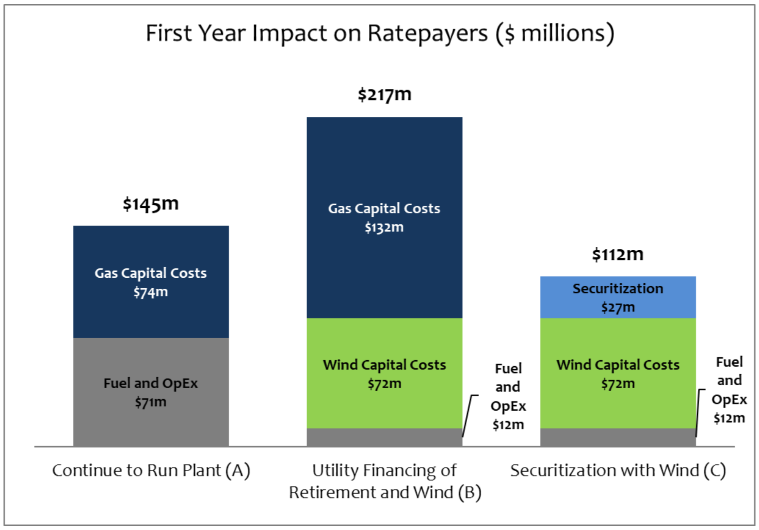
Marshalltown Generating Station

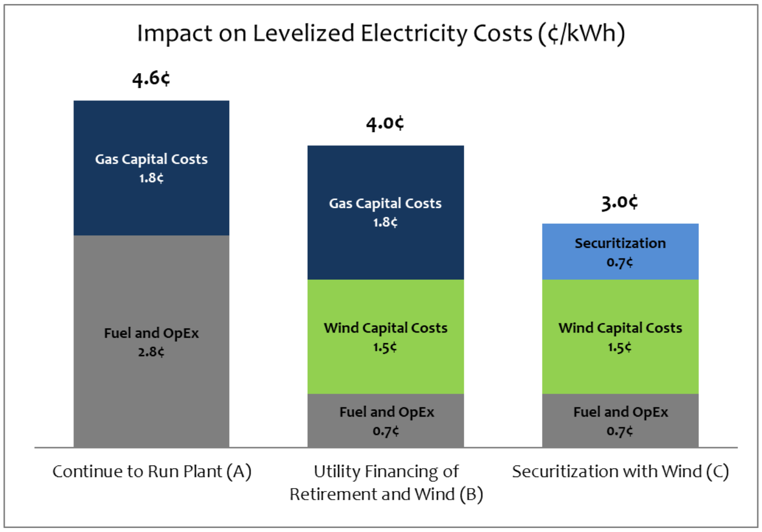
Effect on Revenue Requirement and LCOE – Full PTC



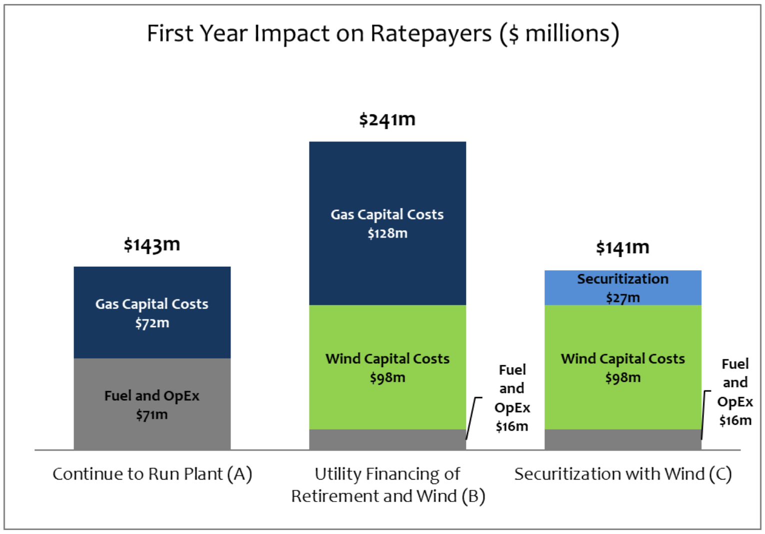


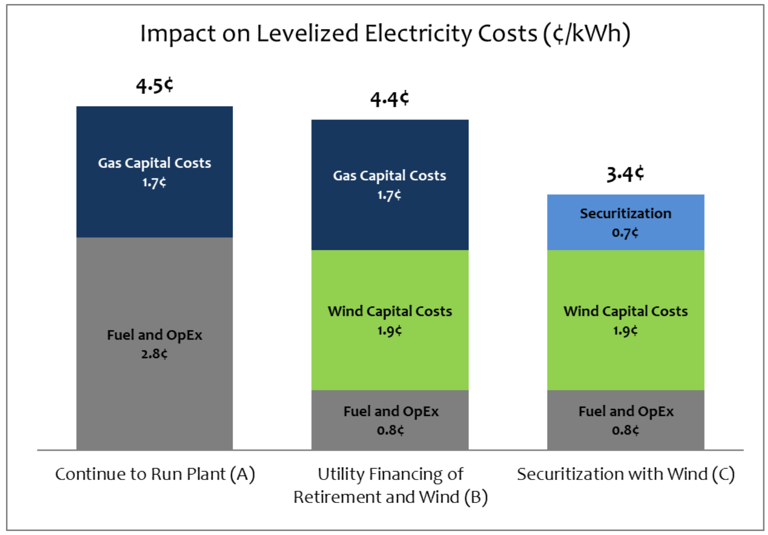
Effect on Revenue Requirement and LCOE – 80% PTC



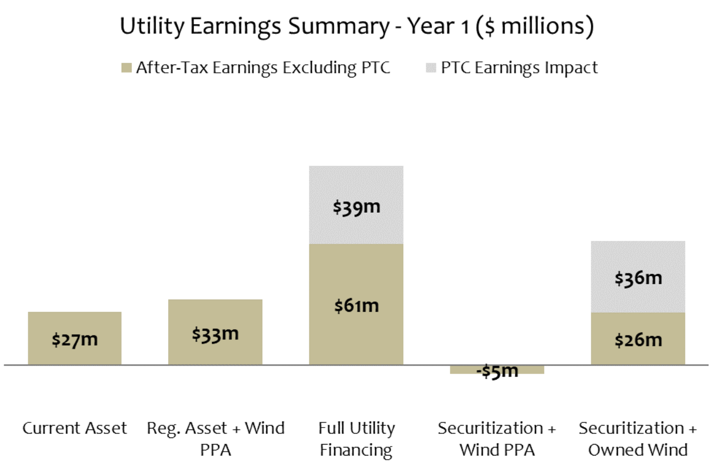


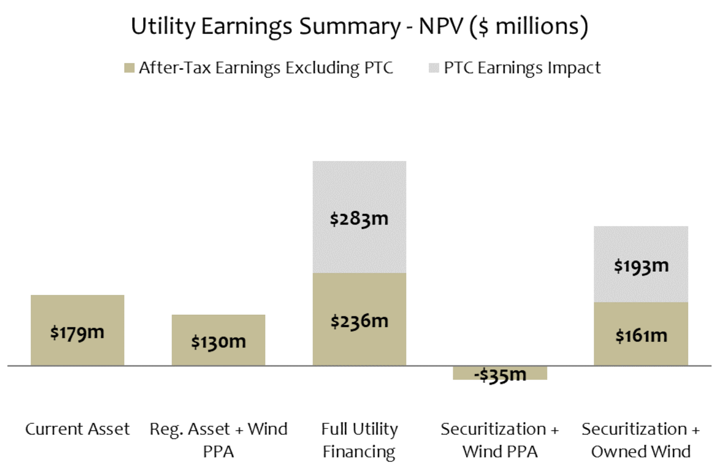
Effect on Revenue Requirement and LCOE – 60% PTC





Effect on Utility Earnings – 80% PTC





Source: RMI analysis based on 2018 EIA 923; 2018 EIA 860; IPL 2013-2018 FERC Form 1; MISO Market Reports from 2013-2018.

APPENDIX B

Generator Input Assumptions

Burlington Station	**Unit Name**
Existing Brown Plant Snapshot:	
Plant Type	Conventional Steam Coal
Current Net Plant Balance ($)	$21,003,422
Current Total Retirement Cost ($)	$44,802,222
Net Capacity (MW)	211.95
Assumed Year of Early Retirement	2021
Current Remaining Life (Yrs)	9
Amortization Period of Regulatory Asset with Early Retirement	10
Capacity Factor (%)	64.06%
Net Generation (MWh)	1,189,433
NPV Brown Plant Generation at Utility ROE Discount Rate (MWh)	6,960,253
Operating Costs ($/MWh)	$22.63
Fuel Portion of Coal MCOE	75%
Fuel Hedge Adder	0%
Securitization and Green Bond Assumptions:	
Securitization Assumed Interest Rate	3.10%
Securitization Bond Tenor	9
Green Bond Assumed Interest Rate	3.75%
Green Bond Tenor	9
Share of Securitization Savings For Transition Assistance	15%
Include Transition Assistance in Regulatory Asset Case?	Yes
Calculate Savings Relative to Regulatory Asset Case or BAU Case?	BAU Case
Does the green bond affect the utility's allowed ROR?	No
Is the utility recycling the proceeds from securitization or green bond?	Yes
Is the capital structure of the new facility different from the utility's?	No
If yes, input the new facility's debt ratio here:	50.00%
Does the new facility's capital structure impact the utility's allowed ROR?	No
Other Financial Metrics/Ratios:	
Ratepayer Discount Rate	7.00%
Shareholder Discount Rate	9.60%
Utility's Allowed ROR (%)	7.30%
Utility's Allowed ROR used (accounting for deductability of interest)	6.51%
Plant Allowed ROR used (accounting for deductability of interest)	6.51%
Wind Allowed ROR used (accounting for deductability of interest)	7.19%
Solar Allowed ROR used (accounting for deductability of interest)	6.51%
Equity Ratio (%)	49.00%
Utility's Allowed ROE (%)	9.60%
Existing Plant Allowed ROE (%)	9.60%
Wind Allowed ROE (%)	11.00%
Solar Allowed ROE (%)	9.60%
Assumed Allowed Preferred Equity Ratio	0.00%
Assumed Allowed Return on Preferred Equity (ROPE)	0.00%
Implied Debt Ratio	51.00%
Implied Cost of Debt	5.09%
Cost of Debt (%)	3.75%
Federal Corporate Tax Rate	21.00%
Utility's Blended Tax Rate (%)	30.48%
Brown Plant Assumed Starting Book-Tax Disparity	50.00%
Macro Inflation	2.0%
O&M and Fuel Escalator	2.5%
Utility-Owned Wind Metrics:	
Wind Services Value as Percentage of Brown Plant Services Value	88%
Required Generation (MWh)	1,351,628
Wind Capacity Factor (%)	47%
Assumed Wind Capacity Factor in the Region (%)	47%
Req'd Replacement Wind Capacity (MW)	328
Wind Plant Useful Life (Yrs)	30
Capital Cost of Wind ($/MW)	$1,350,000
Transmission Costs ($/MW)	$0
Total Capital Cost of Utility-Owned Wind ($)	$443,189,146
NPV MACRS (%)	0.78
NPV Wind Generation at Utility ROE Discount Rate (MWh)	13,179,407
Impact of Capital Costs on NPV Revenue Required ($)	$486,310,615
PTC Price ($/MWh)	$20.31
NPV PTC Value ($)	$253,429,968
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$232,880,646
Wind O&M Expense ($/MWh)	$7.00
Wind PPA Metrics:	
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$232,880,646
NPV Wind Generation (MWh)	12,338,402
NPV Wind Generation at Utility Shareholder DR (MWh)	11,828,465
Wind PPA Price ($/MWh)	$23.41
Wind PPA Assumed WACC	9.0%
Wind PPA Period (Yrs)	20
Post-PPA Period O&M Increase	100%
Utility-Owned Solar Metrics:	
Req'd Replacement Solar Capacity (MW)	485
Solar Capacity Factor (%)	28%
Solar Plant Useful Life (Yrs)	30
Capital Cost of Solar ($/MW)	$1,100,000
Transmission Costs ($/MW)	$0
Total Cost of Utility-Owned Solar ($)	$533,421,518
NPV Solar Generation at Utility ROE Discount Rate (MWh)	11,597,878
ITC	30%
Solar O&M Expense ($/MWh)	$3.26
Post-PPA Period O&M Increase	100%
Solar PPA Metrics:	
Solar PPA Price ($/MWh)	$33.59
NPV Solar Generation (MWh)	12,600,870
NPV Solar Generation at Utility Shareholder DR (MWh)	10,409,049
Solar PPA Assumed WACC	7.00%
Solar PPA Period (Yrs)	20
Market-Indexed Solar PPA Metrics:	
Assumed Cost of Debt	5.09%
Assumed Cost of Equity	9.60%
Assumed Fraction of Debt (%)	51.00%
Size of Market-Indexed PPA (MW) (max. 300 in UT)	485
Market-Indexed Solar PPA Price ($/MWh)	$26.33
Market-Indexed Solar PPA Assumed WACC	6.51%
Market-Indexed Solar PPA Period (Yrs)	30
Market-Indexed Solar Price ($/MWh) without ITC	$33.15

Lansing Unit 4	**Unit Name**
Existing Brown Plant Snapshot:	
Plant Type	Conventional Steam Coal
Current Net Plant Balance ($)	$237,787,822
Current Total Retirement Cost ($)	$325,549,672
Net Capacity (MW)	274.50
Assumed Year of Early Retirement	2021
Current Remaining Life (Yrs)	21
Amortization Period of Regulatory Asset with Early Retirement	10
Capacity Factor (%)	36.73%
Net Generation (MWh)	883,147
NPV Brown Plant Generation at Utility ROE Discount Rate (MWh)	7,857,486
Operating Costs ($/MWh)	$37.26
Fuel Portion of Coal MCOE	75%
Fuel Hedge Adder	0%
Securitization and Green Bond Assumptions:	
Securitization Assumed Interest Rate	3.10%
Securitization Bond Tenor	21
Green Bond Assumed Interest Rate	3.75%
Green Bond Tenor	21
Share of Securitization Savings For Transition Assistance	15%
Include Transition Assistance in Regulatory Asset Case?	Yes
Calculate Savings Relative to Regulatory Asset Case or BAU Case?	BAU Case
Does the green bond affect the utility's allowed ROR?	No
Is the utility recycling the proceeds from securitization or green bond?	Yes
Is the capital structure of the new facility different from the utility's?	No
If yes, input the new facility's debt ratio here:	50.00%
Does the new facility's capital structure impact the utility's allowed ROR?	No
Other Financial Metrics/Ratios:	
Ratepayer Discount Rate	7.00%
Shareholder Discount Rate	9.60%
Utility's Allowed ROR (%)	7.30%
Utility's Allowed ROR used (accounting for deductability of interest)	6.51%
Plant Allowed ROR used (accounting for deductability of interest)	6.51%
Wind Allowed ROR used (accounting for deductability of interest)	7.19%
Solar Allowed ROR used (accounting for deductability of interest)	6.51%
Equity Ratio (%)	49.00%
Utility's Allowed ROE (%)	9.60%
Existing Plant Allowed ROE (%)	9.60%
Wind Allowed ROE (%)	11.00%
Solar Allowed ROE (%)	9.60%
Assumed Allowed Preferred Equity Ratio	0.00%
Assumed Allowed Return on Preferred Equity (ROPE)	0.00%
Implied Debt Ratio	51.00%
Implied Cost of Debt	5.09%
Cost of Debt (%)	3.75%
Federal Corporate Tax Rate	21.00%
Utility's Blended Tax Rate (%)	30.48%
Brown Plant Assumed Starting Book-Tax Disparity	50.00%
Macro Inflation	2.0%
O&M and Fuel Escalator	2.5%
Utility-Owned Wind Metrics:	
Wind Services Value as Percentage of Brown Plant Services Value	77%
Required Generation (MWh)	1,146,944
Wind Capacity Factor (%)	47%
Assumed Wind Capacity Factor in the Region (%)	47%
Req'd Replacement Wind Capacity (MW)	279
Wind Plant Useful Life (Yrs)	30
Capital Cost of Wind ($/MW)	$1,350,000
Transmission Costs ($/MW)	$0
Total Capital Cost of Utility-Owned Wind ($)	$376,074,665
NPV MACRS (%)	0.78
NPV Wind Generation at Utility ROE Discount Rate (MWh)	11,183,579
Impact of Capital Costs on NPV Revenue Required ($)	$412,666,021
PTC Price ($/MWh)	$20.31
NPV PTC Value ($)	$215,051,725
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$197,614,296
Wind O&M Expense ($/MWh)	$7.00
Wind PPA Metrics:	
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$197,614,296
NPV Wind Generation (MWh)	10,469,932
NPV Wind Generation at Utility Shareholder DR (MWh)	10,037,218
Wind PPA Price ($/MWh)	$23.41
Wind PPA Assumed WACC	9.0%
Wind PPA Period (Yrs)	20
Post-PPA Period O&M Increase	100%
Utility-Owned Solar Metrics:	
Req'd Replacement Solar Capacity (MW)	360
Solar Capacity Factor (%)	28%
Solar Plant Useful Life (Yrs)	30
Capital Cost of Solar ($/MW)	$1,100,000
Transmission Costs ($/MW)	$0
Total Cost of Utility-Owned Solar ($)	$396,062,337
NPV Solar Generation at Utility ROE Discount Rate (MWh)	8,611,356
ITC	30%
Solar O&M Expense ($/MWh)	$3.26
Post-PPA Period O&M Increase	100%
Solar PPA Metrics:	
Solar PPA Price ($/MWh)	$33.59
NPV Solar Generation (MWh)	9,356,072
NPV Solar Generation at Utility Shareholder DR (MWh)	7,728,658
Solar PPA Assumed WACC	7.00%
Solar PPA Period (Yrs)	20
Market-Indexed Solar PPA Metrics:	
Assumed Cost of Debt	5.09%
Assumed Cost of Equity	9.60%
Assumed Fraction of Debt (%)	51.00%
Size of Market-Indexed PPA (MW) (max. 300 in UT)	360
Market-Indexed Solar PPA Price ($/MWh)	$26.33
Market-Indexed Solar PPA Assumed WACC	6.51%
Market-Indexed Solar PPA Period (Yrs)	30
Market-Indexed Solar Price ($/MWh) without ITC	$33.15

Louisa (IPL)	**Unit Name**
Existing Brown Plant Snapshot:	
Plant Type	Conventional Steam Coal
Current Net Plant Balance ($)	$9,528,470
Current Total Retirement Cost ($)	$16,451,920
Net Capacity (MW)	32.48
Assumed Year of Early Retirement	2021
Current Remaining Life (Yrs)	20
Amortization Period of Regulatory Asset with Early Retirement	10
Capacity Factor (%)	69.19%
Net Generation (MWh)	196,829
NPV Brown Plant Generation at Utility ROE Discount Rate (MWh)	1,722,504
Operating Costs ($/MWh)	$23.92
Fuel Portion of Coal MCOE	75%
Fuel Hedge Adder	0%
Securitization and Green Bond Assumptions:	
Securitization Assumed Interest Rate	3.10%
Securitization Bond Tenor	20
Green Bond Assumed Interest Rate	3.75%
Green Bond Tenor	20
Share of Securitization Savings For Transition Assistance	15%
Include Transition Assistance in Regulatory Asset Case?	Yes
Calculate Savings Relative to Regulatory Asset Case or BAU Case?	BAU Case
Does the green bond affect the utility's allowed ROR?	No
Is the utility recycling the proceeds from securitization or green bond?	Yes
Is the capital structure of the new facility different from the utility's?	No
If yes, input the new facility's debt ratio here:	50.00%
Does the new facility's capital structure impact the utility's allowed ROR?	No
Other Financial Metrics/Ratios:	
Ratepayer Discount Rate	7.00%
Shareholder Discount Rate	9.60%
Utility's Allowed ROR (%)	7.30%
Utility's Allowed ROR used (accounting for deductability of interest)	6.51%
Plant Allowed ROR used (accounting for deductability of interest)	6.51%
Wind Allowed ROR used (accounting for deductability of interest)	7.19%
Solar Allowed ROR used (accounting for deductability of interest)	6.51%
Equity Ratio (%)	49.00%
Utility's Allowed ROE (%)	9.60%
Existing Plant Allowed ROE (%)	9.60%
Wind Allowed ROE (%)	11.00%
Solar Allowed ROE (%)	9.60%
Assumed Allowed Preferred Equity Ratio	0.00%
Assumed Allowed Return on Preferred Equity (ROPE)	0.00%
Implied Debt Ratio	51.00%
Implied Cost of Debt	5.09%
Cost of Debt (%)	3.75%
Federal Corporate Tax Rate	21.00%
Utility's Blended Tax Rate (%)	30.48%
Brown Plant Assumed Starting Book-Tax Disparity	50.00%
Macro Inflation	2.0%
O&M and Fuel Escalator	2.5%
Utility-Owned Wind Metrics:	
Wind Services Value as Percentage of Brown Plant Services Value	77%
Required Generation (MWh)	255,622
Wind Capacity Factor (%)	47%
Assumed Wind Capacity Factor in the Region (%)	47%
Req'd Replacement Wind Capacity (MW)	62
Wind Plant Useful Life (Yrs)	30
Capital Cost of Wind ($/MW)	$1,350,000
Transmission Costs ($/MW)	$0
Total Capital Cost of Utility-Owned Wind ($)	$83,816,641
NPV MACRS (%)	0.78
NPV Wind Generation at Utility ROE Discount Rate (MWh)	2,492,511
Impact of Capital Costs on NPV Revenue Required ($)	$91,971,842
PTC Price ($/MWh)	$20.31
NPV PTC Value ($)	$47,929,082
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$44,042,761
Wind O&M Expense ($/MWh)	$7.00
Wind PPA Metrics:	
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$44,042,761
NPV Wind Generation (MWh)	2,333,458
NPV Wind Generation at Utility Shareholder DR (MWh)	2,237,018
Wind PPA Price ($/MWh)	$23.41
Wind PPA Assumed WACC	9.0%
Wind PPA Period (Yrs)	20
Post-PPA Period O&M Increase	100%
Utility-Owned Solar Metrics:	
Req'd Replacement Solar Capacity (MW)	80
Solar Capacity Factor (%)	28%
Solar Plant Useful Life (Yrs)	30
Capital Cost of Solar ($/MW)	$1,100,000
Transmission Costs ($/MW)	$0
Total Cost of Utility-Owned Solar ($)	$88,271,341
NPV Solar Generation at Utility ROE Discount Rate (MWh)	1,919,233
ITC	30%
Solar O&M Expense ($/MWh)	$3.26
Post-PPA Period O&M Increase	100%
Solar PPA Metrics:	
Solar PPA Price ($/MWh)	$33.59
NPV Solar Generation (MWh)	2,085,210
NPV Solar Generation at Utility Shareholder DR (MWh)	1,722,504
Solar PPA Assumed WACC	7.00%
Solar PPA Period (Yrs)	20
Market-Indexed Solar PPA Metrics:	
Assumed Cost of Debt	5.09%
Assumed Cost of Equity	9.60%
Assumed Fraction of Debt (%)	51.00%
Size of Market-Indexed PPA (MW) (max. 300 in UT)	80
Market-Indexed Solar PPA Price ($/MWh)	$26.33
Market-Indexed Solar PPA Assumed WACC	6.51%
Market-Indexed Solar PPA Period (Yrs)	30
Market-Indexed Solar Price ($/MWh) without ITC	$33.15

Neal Station 3 (IPL)	**Unit Name**
Existing Brown Plant Snapshot:	
Plant Type	Conventional Steam Coal
Current Net Plant Balance ($)	$24,990,205
Current Total Retirement Cost ($)	$51,222,705
Net Capacity (MW)	163.55
Assumed Year of Early Retirement	2021
Current Remaining Life (Yrs)	13
Amortization Period of Regulatory Asset with Early Retirement	10
Capacity Factor (%)	44.88%
Net Generation (MWh)	642,939
NPV Brown Plant Generation at Utility ROE Discount Rate (MWh)	4,663,233
Operating Costs ($/MWh)	$37.13
Fuel Portion of Coal MCOE	75%
Fuel Hedge Adder	0%
Securitization and Green Bond Assumptions:	
Securitization Assumed Interest Rate	3.10%
Securitization Bond Tenor	13
Green Bond Assumed Interest Rate	3.75%
Green Bond Tenor	13
Share of Securitization Savings For Transition Assistance	15%
Include Transition Assistance in Regulatory Asset Case?	Yes
Calculate Savings Relative to Regulatory Asset Case or BAU Case?	BAU Case
Does the green bond affect the utility's allowed ROR?	No
Is the utility recycling the proceeds from securitization or green bond?	Yes
Is the capital structure of the new facility different from the utility's?	No
If yes, input the new facility's debt ratio here:	50.00%
Does the new facility's capital structure impact the utility's allowed ROR?	No
Other Financial Metrics/Ratios:	
Ratepayer Discount Rate	7.00%
Shareholder Discount Rate	9.60%
Utility's Allowed ROR (%)	7.30%
Utility's Allowed ROR used (accounting for deductability of interest)	6.51%
Plant Allowed ROR used (accounting for deductability of interest)	6.51%
Wind Allowed ROR used (accounting for deductability of interest)	7.19%
Solar Allowed ROR used (accounting for deductability of interest)	6.51%
Equity Ratio (%)	49.00%
Utility's Allowed ROE (%)	9.60%
Existing Plant Allowed ROE (%)	9.60%
Wind Allowed ROE (%)	11.00%
Solar Allowed ROE (%)	9.60%
Assumed Allowed Preferred Equity Ratio	0.00%
Assumed Allowed Return on Preferred Equity (ROPE)	0.00%
Implied Debt Ratio	51.00%
Implied Cost of Debt	5.09%
Cost of Debt (%)	3.75%
Federal Corporate Tax Rate	21.00%
Utility's Blended Tax Rate (%)	30.48%
Brown Plant Assumed Starting Book-Tax Disparity	50.00%
Macro Inflation	2.0%
O&M and Fuel Escalator	2.5%
Utility-Owned Wind Metrics:	
Wind Services Value as Percentage of Brown Plant Services Value	74%
Required Generation (MWh)	868,836
Wind Capacity Factor (%)	47%
Assumed Wind Capacity Factor in the Region (%)	47%
Req'd Replacement Wind Capacity (MW)	211
Wind Plant Useful Life (Yrs)	30
Capital Cost of Wind ($/MW)	$1,350,000
Transmission Costs ($/MW)	$0
Total Capital Cost of Utility-Owned Wind ($)	$284,885,178
NPV MACRS (%)	0.78
NPV Wind Generation at Utility ROE Discount Rate (MWh)	8,471,818
Impact of Capital Costs on NPV Revenue Required ($)	$312,603,969
PTC Price ($/MWh)	$20.31
NPV PTC Value ($)	$162,906,611
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$149,697,359
Wind O&M Expense ($/MWh)	$7.00
Wind PPA Metrics:	
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$149,697,359
NPV Wind Generation (MWh)	7,931,214
NPV Wind Generation at Utility Shareholder DR (MWh)	7,603,423
Wind PPA Price ($/MWh)	$23.41
Wind PPA Assumed WACC	9.0%
Wind PPA Period (Yrs)	20
Post-PPA Period O&M Increase	100%
Utility-Owned Solar Metrics:	
Req'd Replacement Solar Capacity (MW)	262
Solar Capacity Factor (%)	28%
Solar Plant Useful Life (Yrs)	30
Capital Cost of Solar ($/MW)	$1,100,000
Transmission Costs ($/MW)	$0
Total Cost of Utility-Owned Solar ($)	$288,336,962
NPV Solar Generation at Utility ROE Discount Rate (MWh)	6,269,145
ITC	30%
Solar O&M Expense ($/MWh)	$3.26
Post-PPA Period O&M Increase	100%
Solar PPA Metrics:	
Solar PPA Price ($/MWh)	$33.59
NPV Solar Generation (MWh)	6,811,305
NPV Solar Generation at Utility Shareholder DR (MWh)	5,626,533
Solar PPA Assumed WACC	7.00%
Solar PPA Period (Yrs)	20
Market-Indexed Solar PPA Metrics:	
Assumed Cost of Debt	5.09%
Assumed Cost of Equity	9.60%
Assumed Fraction of Debt (%)	51.00%
Size of Market-Indexed PPA (MW) (max. 300 in UT)	262
Market-Indexed Solar PPA Price ($/MWh)	$26.33
Market-Indexed Solar PPA Assumed WACC	6.51%
Market-Indexed Solar PPA Period (Yrs)	30
Market-Indexed Solar Price ($/MWh) without ITC	$33.15

Neal Station 4 (IPL)	**Unit Name**
Existing Brown Plant Snapshot:	
Plant Type	Conventional Steam Coal
Current Net Plant Balance ($)	$23,362,490
Current Total Retirement Cost ($)	$57,916,390
Net Capacity (MW)	178.85
Assumed Year of Early Retirement	2021
Current Remaining Life (Yrs)	10
Amortization Period of Regulatory Asset with Early Retirement	10
Capacity Factor (%)	51.45%
Net Generation (MWh)	806,089
NPV Brown Plant Generation at Utility ROE Discount Rate (MWh)	5,039,336
Operating Costs ($/MWh)	$27.65
Fuel Portion of Coal MCOE	75%
Fuel Hedge Adder	0%
Securitization and Green Bond Assumptions:	
Securitization Assumed Interest Rate	3.10%
Securitization Bond Tenor	10
Green Bond Assumed Interest Rate	3.75%
Green Bond Tenor	10
Share of Securitization Savings For Transition Assistance	15%
Include Transition Assistance in Regulatory Asset Case?	Yes
Calculate Savings Relative to Regulatory Asset Case or BAU Case?	BAU Case
Does the green bond affect the utility's allowed ROR?	No
Is the utility recycling the proceeds from securitization or green bond?	Yes
Is the capital structure of the new facility different from the utility's?	No
If yes, input the new facility's debt ratio here:	50.00%
Does the new facility's capital structure impact the utility's allowed ROR?	No
Other Financial Metrics/Ratios:	
Ratepayer Discount Rate	7.00%
Shareholder Discount Rate	9.60%
Utility's Allowed ROR (%)	7.30%
Utility's Allowed ROR used (accounting for deductability of interest)	6.51%
Plant Allowed ROR used (accounting for deductability of interest)	6.51%
Wind Allowed ROR used (accounting for deductability of interest)	7.19%
Solar Allowed ROR used (accounting for deductability of interest)	6.51%
Equity Ratio (%)	49.00%
Utility's Allowed ROE (%)	9.60%
Existing Plant Allowed ROE (%)	9.60%
Wind Allowed ROE (%)	11.00%
Solar Allowed ROE (%)	9.60%
Assumed Allowed Preferred Equity Ratio	0.00%
Assumed Allowed Return on Preferred Equity (ROPE)	0.00%
Implied Debt Ratio	51.00%
Implied Cost of Debt	5.09%
Cost of Debt (%)	3.75%
Federal Corporate Tax Rate	21.00%
Utility's Blended Tax Rate (%)	30.48%
Brown Plant Assumed Starting Book-Tax Disparity	50.00%
Macro Inflation	2.0%
O&M and Fuel Escalator	2.5%
Utility-Owned Wind Metrics:	
Wind Services Value as Percentage of Brown Plant Services Value	79%
Required Generation (MWh)	1,020,366
Wind Capacity Factor (%)	47%
Assumed Wind Capacity Factor in the Region (%)	47%
Req'd Replacement Wind Capacity (MW)	248
Wind Plant Useful Life (Yrs)	30
Capital Cost of Wind ($/MW)	$1,350,000
Transmission Costs ($/MW)	$0
Total Capital Cost of Utility-Owned Wind ($)	$334,570,548
NPV MACRS (%)	0.78
NPV Wind Generation at Utility ROE Discount Rate (MWh)	9,949,344
Impact of Capital Costs on NPV Revenue Required ($)	$367,123,632
PTC Price ($/MWh)	$20.31
NPV PTC Value ($)	$191,318,321
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$175,805,311
Wind O&M Expense ($/MWh)	$7.00
Wind PPA Metrics:	
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$175,805,311
NPV Wind Generation (MWh)	9,314,456
NPV Wind Generation at Utility Shareholder DR (MWh)	8,929,497
Wind PPA Price ($/MWh)	$23.41
Wind PPA Assumed WACC	9.0%
Wind PPA Period (Yrs)	20
Post-PPA Period O&M Increase	100%
Utility-Owned Solar Metrics:	
Req'd Replacement Solar Capacity (MW)	329
Solar Capacity Factor (%)	28%
Solar Plant Useful Life (Yrs)	30
Capital Cost of Solar ($/MW)	$1,100,000
Transmission Costs ($/MW)	$0
Total Cost of Utility-Owned Solar ($)	$361,504,362
NPV Solar Generation at Utility ROE Discount Rate (MWh)	7,859,982
ITC	30%
Solar O&M Expense ($/MWh)	$3.26
Post-PPA Period O&M Increase	100%
Solar PPA Metrics:	
Solar PPA Price ($/MWh)	$33.59
NPV Solar Generation (MWh)	8,539,718
NPV Solar Generation at Utility Shareholder DR (MWh)	7,054,303
Solar PPA Assumed WACC	7.00%
Solar PPA Period (Yrs)	20
Market-Indexed Solar PPA Metrics:	
Assumed Cost of Debt	5.09%
Assumed Cost of Equity	9.60%
Assumed Fraction of Debt (%)	51.00%
Size of Market-Indexed PPA (MW) (max. 300 in UT)	329
Market-Indexed Solar PPA Price ($/MWh)	$26.33
Market-Indexed Solar PPA Assumed WACC	6.51%
Market-Indexed Solar PPA Period (Yrs)	30
Market-Indexed Solar Price ($/MWh) without ITC	$33.15

Ottumwa (IPL)	**Unit Name**
Existing Brown Plant Snapshot:	
Plant Type	Conventional Steam Coal
Current Net Plant Balance ($)	$172,963,814
Current Total Retirement Cost ($)	$265,640,764
Net Capacity (MW)	348.43
Assumed Year of Early Retirement	2021
Current Remaining Life (Yrs)	18
Amortization Period of Regulatory Asset with Early Retirement	10
Capacity Factor (%)	62.52%
Net Generation (MWh)	1,908,346
NPV Brown Plant Generation at Utility ROE Discount Rate (MWh)	16,060,959
Operating Costs ($/MWh)	$25.54
Fuel Portion of Coal MCOE	75%
Fuel Hedge Adder	0%
Securitization and Green Bond Assumptions:	
Securitization Assumed Interest Rate	3.10%
Securitization Bond Tenor	18
Green Bond Assumed Interest Rate	3.75%
Green Bond Tenor	18
Share of Securitization Savings For Transition Assistance	15%
Include Transition Assistance in Regulatory Asset Case?	Yes
Calculate Savings Relative to Regulatory Asset Case or BAU Case?	BAU Case
Does the green bond affect the utility's allowed ROR?	No
Is the utility recycling the proceeds from securitization or green bond?	Yes
Is the capital structure of the new facility different from the utility's?	No
If yes, input the new facility's debt ratio here:	50.00%
Does the new facility's capital structure impact the utility's allowed ROR?	No
Other Financial Metrics/Ratios:	
Ratepayer Discount Rate	7.00%
Shareholder Discount Rate	9.60%
Utility's Allowed ROR (%)	7.30%
Utility's Allowed ROR used (accounting for deductability of interest)	6.51%
Plant Allowed ROR used (accounting for deductability of interest)	6.51%
Wind Allowed ROR used (accounting for deductability of interest)	7.19%
Solar Allowed ROR used (accounting for deductability of interest)	6.51%
Equity Ratio (%)	49.00%
Utility's Allowed ROE (%)	9.60%
Existing Plant Allowed ROE (%)	9.60%
Wind Allowed ROE (%)	11.00%
Solar Allowed ROE (%)	9.60%
Assumed Allowed Preferred Equity Ratio	0.00%
Assumed Allowed Return on Preferred Equity (ROPE)	0.00%
Implied Debt Ratio	51.00%
Implied Cost of Debt	5.09%
Cost of Debt (%)	3.75%
Federal Corporate Tax Rate	21.00%
Utility's Blended Tax Rate (%)	30.48%
Brown Plant Assumed Starting Book-Tax Disparity	50.00%
Macro Inflation	2.0%
O&M and Fuel Escalator	2.5%
Utility-Owned Wind Metrics:	
Wind Services Value as Percentage of Brown Plant Services Value	94%
Required Generation (MWh)	2,030,156
Wind Capacity Factor (%)	47%
Assumed Wind Capacity Factor in the Region (%)	47%
Req'd Replacement Wind Capacity (MW)	493
Wind Plant Useful Life (Yrs)	30
Capital Cost of Wind ($/MW)	$1,350,000
Transmission Costs ($/MW)	$0
Total Capital Cost of Utility-Owned Wind ($)	$665,673,332
NPV MACRS (%)	0.78
NPV Wind Generation at Utility ROE Discount Rate (MWh)	19,795,565
Impact of Capital Costs on NPV Revenue Required ($)	$730,442,093
PTC Price ($/MWh)	$20.31
NPV PTC Value ($)	$380,653,662
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$349,788,431
Wind O&M Expense ($/MWh)	$7.00
Wind PPA Metrics:	
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$349,788,431
NPV Wind Generation (MWh)	18,532,369
NPV Wind Generation at Utility Shareholder DR (MWh)	17,766,441
Wind PPA Price ($/MWh)	$23.41
Wind PPA Assumed WACC	9.0%
Wind PPA Period (Yrs)	20
Post-PPA Period O&M Increase	100%
Utility-Owned Solar Metrics:	
Req'd Replacement Solar Capacity (MW)	778
Solar Capacity Factor (%)	28%
Solar Plant Useful Life (Yrs)	30
Capital Cost of Solar ($/MW)	$1,100,000
Transmission Costs ($/MW)	$0
Total Cost of Utility-Owned Solar ($)	$855,830,492
NPV Solar Generation at Utility ROE Discount Rate (MWh)	18,607,831
ITC	30%
Solar O&M Expense ($/MWh)	$3.26
Post-PPA Period O&M Increase	100%
Solar PPA Metrics:	
Solar PPA Price ($/MWh)	$33.59
NPV Solar Generation (MWh)	20,217,049
NPV Solar Generation at Utility Shareholder DR (MWh)	16,700,455
Solar PPA Assumed WACC	7.00%
Solar PPA Period (Yrs)	20
Market-Indexed Solar PPA Metrics:	
Assumed Cost of Debt	5.09%
Assumed Cost of Equity	9.60%
Assumed Fraction of Debt (%)	51.00%
Size of Market-Indexed PPA (MW) (max. 300 in UT)	778
Market-Indexed Solar PPA Price ($/MWh)	$26.33
Market-Indexed Solar PPA Assumed WACC	6.51%
Market-Indexed Solar PPA Period (Yrs)	30
Market-Indexed Solar Price ($/MWh) without ITC	$33.15

Emery	**Unit Name**
Existing Brown Plant Snapshot:	
Plant Type	Natural Gas Fired Combined Cycle
Current Net Plant Balance ($)	$257,110,962
Current Total Retirement Cost ($)	$306,716,392
Net Capacity (MW)	602.82
Assumed Year of Early Retirement	2021
Current Remaining Life (Yrs)	17
Amortization Period of Regulatory Asset with Early Retirement	10
Capacity Factor (%)	52.55%
Net Generation (MWh)	2,774,796
NPV Brown Plant Generation at Utility ROE Discount Rate (MWh)	22,820,247
Operating Costs ($/MWh)	$22.84
Fuel Portion of Coal MCOE	75%
Fuel Hedge Adder	0%
Securitization and Green Bond Assumptions:	
Securitization Assumed Interest Rate	3.10%
Securitization Bond Tenor	17
Green Bond Assumed Interest Rate	3.75%
Green Bond Tenor	17
Share of Securitization Savings For Transition Assistance	15%
Include Transition Assistance in Regulatory Asset Case?	Yes
Calculate Savings Relative to Regulatory Asset Case or BAU Case?	BAU Case
Does the green bond affect the utility's allowed ROR?	No
Is the utility recycling the proceeds from securitization or green bond?	Yes
Is the capital structure of the new facility different from the utility's?	No
If yes, input the new facility's debt ratio here:	50.00%
Does the new facility's capital structure impact the utility's allowed ROR?	No
Other Financial Metrics/Ratios:	
Ratepayer Discount Rate	7.00%
Shareholder Discount Rate	9.60%
Utility's Allowed ROR (%)	7.30%
Utility's Allowed ROR used (accounting for deductability of interest)	6.51%
Plant Allowed ROR used (accounting for deductability of interest)	7.80%
Wind Allowed ROR used (accounting for deductability of interest)	7.19%
Solar Allowed ROR used (accounting for deductability of interest)	6.51%
Equity Ratio (%)	49.00%
Utility's Allowed ROE (%)	9.60%
Existing Plant Allowed ROE (%)	12.23%
Wind Allowed ROE (%)	11.00%
Solar Allowed ROE (%)	9.60%
Assumed Allowed Preferred Equity Ratio	0.00%
Assumed Allowed Return on Preferred Equity (ROPE)	0.00%
Implied Debt Ratio	51.00%
Implied Cost of Debt	5.09%
Cost of Debt (%)	3.75%
Federal Corporate Tax Rate	21.00%
Utility's Blended Tax Rate (%)	30.48%
Brown Plant Assumed Starting Book-Tax Disparity	50.00%
Macro Inflation	2.0%
O&M and Fuel Escalator	2.5%
Utility-Owned Wind Metrics:	
Wind Services Value as Percentage of Brown Plant Services Value	70%
Required Generation (MWh)	3,963,994
Wind Capacity Factor (%)	47%
Assumed Wind Capacity Factor in the Region (%)	47%
Req'd Replacement Wind Capacity (MW)	963
Wind Plant Useful Life (Yrs)	30
Capital Cost of Wind ($/MW)	$1,350,000
Transmission Costs ($/MW)	$0
Total Capital Cost of Utility-Owned Wind ($)	$1,299,764,911
NPV MACRS (%)	0.78
NPV Wind Generation at Utility ROE Discount Rate (MWh)	38,651,963
Impact of Capital Costs on NPV Revenue Required ($)	$1,426,229,587
PTC Price ($/MWh)	$20.31
NPV PTC Value ($)	$743,247,851
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$682,981,737
Wind O&M Expense ($/MWh)	$7.00
Wind PPA Metrics:	
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$682,981,737
NPV Wind Generation (MWh)	36,185,502
NPV Wind Generation at Utility Shareholder DR (MWh)	34,689,983
Wind PPA Price ($/MWh)	$23.41
Wind PPA Assumed WACC	9.0%
Wind PPA Period (Yrs)	20
Post-PPA Period O&M Increase	100%
Utility-Owned Solar Metrics:	
Req'd Replacement Solar Capacity (MW)	1,131
Solar Capacity Factor (%)	28%
Solar Plant Useful Life (Yrs)	30
Capital Cost of Solar ($/MW)	$1,100,000
Transmission Costs ($/MW)	$0
Total Cost of Utility-Owned Solar ($)	$1,244,404,554
NPV Solar Generation at Utility ROE Discount Rate (MWh)	27,056,374
ITC	30%
Solar O&M Expense ($/MWh)	$3.26
Post-PPA Period O&M Increase	100%
Solar PPA Metrics:	
Solar PPA Price ($/MWh)	$33.59
NPV Solar Generation (MWh)	29,396,227
NPV Solar Generation at Utility Shareholder DR (MWh)	24,282,988
Solar PPA Assumed WACC	7.00%
Solar PPA Period (Yrs)	20
Market-Indexed Solar PPA Metrics:	
Assumed Cost of Debt	5.09%
Assumed Cost of Equity	9.60%
Assumed Fraction of Debt (%)	51.00%
Size of Market-Indexed PPA (MW) (max. 300 in UT)	1,131
Market-Indexed Solar PPA Price ($/MWh)	$26.33
Market-Indexed Solar PPA Assumed WACC	6.51%
Market-Indexed Solar PPA Period (Yrs)	30
Market-Indexed Solar Price ($/MWh) without ITC	$33.15

Marshalltown Generating Station	**Unit Name**
Existing Brown Plant Snapshot:	
Plant Type	Natural Gas Fired Combined Cycle
Current Net Plant Balance ($)	$585,689,843
Current Total Retirement Cost ($)	$640,723,981
Net Capacity (MW)	705.93
Assumed Year of Early Retirement	2021
Current Remaining Life (Yrs)	29
Amortization Period of Regulatory Asset with Early Retirement	10
Capacity Factor (%)	49.86%
Net Generation (MWh)	3,083,292
NPV Brown Plant Generation at Utility ROE Discount Rate (MWh)	29,867,337
Operating Costs ($/MWh)	$23.14
Fuel Portion of Coal MCOE	75%
Fuel Hedge Adder	0%
Securitization and Green Bond Assumptions:	
Securitization Assumed Interest Rate	3.10%
Securitization Bond Tenor	29
Green Bond Assumed Interest Rate	3.75%
Green Bond Tenor	29
Share of Securitization Savings For Transition Assistance	15%
Include Transition Assistance in Regulatory Asset Case?	Yes
Calculate Savings Relative to Regulatory Asset Case or BAU Case?	BAU Case
Does the green bond affect the utility's allowed ROR?	No
Is the utility recycling the proceeds from securitization or green bond?	Yes
Is the capital structure of the new facility different from the utility's?	No
If yes, input the new facility's debt ratio here:	50.00%
Does the new facility's capital structure impact the utility's allowed ROR?	No
Other Financial Metrics/Ratios:	
Ratepayer Discount Rate	7.00%
Shareholder Discount Rate	9.60%
Utility's Allowed ROR (%)	7.30%
Utility's Allowed ROR used (accounting for deductability of interest)	6.51%
Plant Allowed ROR used (accounting for deductability of interest)	7.19%
Wind Allowed ROR used (accounting for deductability of interest)	7.19%
Solar Allowed ROR used (accounting for deductability of interest)	6.51%
Equity Ratio (%)	49.00%
Utility's Allowed ROE (%)	9.60%
Existing Plant Allowed ROE (%)	11.00%
Wind Allowed ROE (%)	11.00%
Solar Allowed ROE (%)	9.60%
Assumed Allowed Preferred Equity Ratio	0.00%
Assumed Allowed Return on Preferred Equity (ROPE)	0.00%
Implied Debt Ratio	51.00%
Implied Cost of Debt	5.09%
Cost of Debt (%)	3.75%
Federal Corporate Tax Rate	21.00%
Utility's Blended Tax Rate (%)	30.48%
Brown Plant Assumed Starting Book-Tax Disparity	50.00%
Macro Inflation	2.0%
O&M and Fuel Escalator	2.5%
Utility-Owned Wind Metrics:	
Wind Services Value as Percentage of Brown Plant Services Value	77%
Required Generation (MWh)	4,004,275
Wind Capacity Factor (%)	47%
Assumed Wind Capacity Factor in the Region (%)	47%
Req'd Replacement Wind Capacity (MW)	973
Wind Plant Useful Life (Yrs)	30
Capital Cost of Wind ($/MW)	$1,350,000
Transmission Costs ($/MW)	$0
Total Capital Cost of Utility-Owned Wind ($)	$1,312,972,659
NPV MACRS (%)	0.78
NPV Wind Generation at Utility ROE Discount Rate (MWh)	39,044,730
Impact of Capital Costs on NPV Revenue Required ($)	$1,440,722,424
PTC Price ($/MWh)	$20.31
NPV PTC Value ($)	$750,800,471
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$689,921,954
Wind O&M Expense ($/MWh)	$7.00
Wind PPA Metrics:	
Impact on NPV Revenue Required of Capital Costs Net PTC ($)	$689,921,954
NPV Wind Generation (MWh)	36,553,206
NPV Wind Generation at Utility Shareholder DR (MWh)	35,042,490
Wind PPA Price ($/MWh)	$23.41
Wind PPA Assumed WACC	9.0%
Wind PPA Period (Yrs)	20
Post-PPA Period O&M Increase	100%
Utility-Owned Solar Metrics:	
Req'd Replacement Solar Capacity (MW)	1,257
Solar Capacity Factor (%)	28%
Solar Plant Useful Life (Yrs)	30
Capital Cost of Solar ($/MW)	$1,100,000
Transmission Costs ($/MW)	$0
Total Cost of Utility-Owned Solar ($)	$1,382,754,725
NPV Solar Generation at Utility ROE Discount Rate (MWh)	30,064,442
ITC	30%
Solar O&M Expense ($/MWh)	$3.26
Post-PPA Period O&M Increase	100%
Solar PPA Metrics:	
Solar PPA Price ($/MWh)	$33.59
NPV Solar Generation (MWh)	32,664,435
NPV Solar Generation at Utility Shareholder DR (MWh)	26,982,718
Solar PPA Assumed WACC	7.00%
Solar PPA Period (Yrs)	20
Market-Indexed Solar PPA Metrics:	
Assumed Cost of Debt	5.09%
Assumed Cost of Equity	9.60%
Assumed Fraction of Debt (%)	51.00%
Size of Market-Indexed PPA (MW) (max. 300 in UT)	1,257
Market-Indexed Solar PPA Price ($/MWh)	$26.33
Market-Indexed Solar PPA Assumed WACC	6.51%
Market-Indexed Solar PPA Period (Yrs)	30
Market-Indexed Solar Price ($/MWh) without ITC	$33.15

STATE OF IOWA
BEFORE THE IOWA UTILIITIES BOARD

IN RE:	)	
	)	DOCKET NO. RPU-2019-0001
INTERSTATE POWER AND LIGHT COMPANY	)	
	)	
	)	

AFFIDAVIT OF UDAY VARADARAJAN

STATE OF CALIFORNIA	)
	)
COUNTY OF SAN MATEO	)

I, Uday Varadarajan, being first duly sworn on oath, state that I am the same Uday Varadarajan identified in the testimony filed in this docket on August 1, 2019, that I have caused the testimony [and exhibits] to be prepared and am familiar with its contents, and that the testimony [and exhibits] is true and correct to the best of my knowledge and belief as of the date of this affidavit.

/s/ Uday Varadarajan
Uday Varadarajan
August 1, 2019

Subscribed and sworn to me this 1st day of August, 2019.

/s/ William Tsui
William Tsui
Notary Public in and for the
State of California