minnesota power
AN ALLETE COMPANY

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October 1, 2020

VIA ELECTRONIC FILING
Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's 2015-2029 Integrated Resource Plan
Docket No. E015/RP-15-690

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota
Docket No. E015/GR-16-664

In the Matter of Minnesota Power's Petition for Approval of the Energy*Forward* Resource Package
Docket No. E015/AI-17-568

Dear Mr. Seuffert:

Please find the attached Securitization Phase 1 Report which addresses compliance requirements ordered by the Minnesota Public Utilities Commission (or "the Commission") on September 25, 2020 in the above referenced dockets. Minnesota Power (or, "the Company") is pleased to collaborate with the Rocky Mountain Institute ("RMI") as they evaluate securitization as a potential financial option to address the significant remaining balances on the Boswell Energy Center, currently totaling over $780 million and being depreciated through 2035. As stated in the attached report, it is authored by Uday Varadarajan, David Posner, Becky Li and Pintian Chen from RMI. While Minnesota Power was pleased to have provided data and support, the views presented in this study are the responsibility of the authors.

The Boswell Energy Center, located in Cohasset at a combined 823[1] MW, is Minnesota Power's last remaining coal plant and only source of Baseload Power. As the Center for Energy and the Environment ("CEE") noted in its *2020 Host Community Study and*

[1] Boswell Unit 4, totaling 585 MW, is co-owned with Minnesota Power and WPPI Energy. Minnesota Power owns 80% of Boswell Unit 4 at 468 MW, and WPPI owns 20% at 117 MW.

Power Plant Retirements: Community's Perspectives and Realities Webinar, Cohasset is the smallest and most geographically isolated host community in Minnesota. In 2018, property taxes from Boswell Energy Center accounted for nearly 70 percent of Cohasset's tax base, nearly 20 percent of the Grand Rapids School District tax base and 13 percent of Itasca County's tax base. The over $780 million of remaining balances on the Boswell Energy Center are associated with investments Minnesota Power made to install a variety of emission control equipment on the units as recently as 2015. Driven by the Minnesota Mercury Reduction Act and federal environmental regulations, the emissions control projects resulted in significant air and water quality benefits. For example, Boswell Units 3 and 4 mercury air emissions were reduced by over 90 percent, nitrogen oxides emissions by over 70 percent, and sulfur dioxide emissions by around 80 percent in aggregate. The emission control equipment investments also achieved substantial reductions in air emissions of particulate matter and acid gases, as well as lowering freshwater use and reducing wastewater generation. The ability to use securitization to address the remaining balances associated with these investments will be evaluated in both this report and the Phase 2 report to be filed in February 2021.

The Company appreciates the incredible stakeholder participation in its first-of-a-kind Integrated Resource Plan ("IRP") stakeholder engagement process, facilitated by the Great Plains Institute, CEE and Lasky Consulting. This stakeholder process began in 2019 and sought to engage customers, communities, advocates and stakeholders at the local, regional and state level, to collectively explore a wide set of issues related to the Company's upcoming IRP and Baseload Retirement Study. Through a series of stakeholder meetings in the Twin Cities, Minnesota Power's service territory in Northern Minnesota, and virtual meetings after the COVID-19 pandemic began affecting the state, stakeholders shared their insights on the future of Minnesota Power's system and specifically the future of the Boswell Energy Center. RMI will present their findings on securitization to this stakeholder group this fall.

Minnesota Power looks forward to both continued collaboration with RMI and the opportunity to engage with its IRP stakeholder group – specifically with customers, consumer advocates, state agencies, clean energy organizations, the Large Power Intervenor Group and other interested stakeholders - on this financial tool which is not currently in state statutes and has never before been used in the State of Minnesota. Further consultation with stakeholders on securitization is planned as part of the ongoing IRP stakeholder process and stakeholder feedback will be incorporated in the Securitization Phase 2 report and upcoming IRP.

Please feel free to contact me at 218-355-3202 or jjpeterson@mnpower.com with any questions related to this submission.

Respectfully,

Jennifer J. Peterson
Manager – Regulatory Strategy and Policy
Minnesota Power

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Attach.

Using Ratepayer-Backed Bond Securitization for Cost Recovery in Accelerated Asset Retirement

Feasibility Study for Minnesota Power – Phase 1

Rocky Mountain Institute

September 2020

Authors:

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Acknowledgements:

The study was conducted in collaboration with Minnesota Power, an operating division of ALLETE. The authors would like to thank the Minnesota Power team for providing extensive data and analytical support. All views presented in this study are solely the responsibility of the authors.

About Rocky Mountain Institute:

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It 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. RMI has offices in Basalt and Boulder, Colorado; New York City; the San Francisco Bay Area; Washington, D.C.; and Beijing.

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Chapter 1. Introduction

The electricity sector in the U.S. is in transition. Cognizant of near- and long-term regulatory and policy pressure to reduce carbon emissions and the increasingly attractive economics of new renewable energy generation eligible for federal tax incentives, many major U.S. utilities are considering retiring fossil generation assets well before the end of their useful (and regulatorily approved) lives. This transition, however, poses unique challenges for regulated utilities, plant host communities, and power customers under the traditional cost-of-service regulatory regime.

Perhaps the most vexing transition issue in cost-of-service settings is how to manage unrecovered plant balances when the associated assets are deemed suitable for retirement prior to the end of their previously approved accounting service lives. Plant investments are usually recovered evenly over the life of the asset (specifically, through a contribution to rates in the ratemaking process to cover depreciation expenses). If an asset is retired ahead of the previously assumed schedule, accelerating recovery may impose rate burdens on customers (especially in cases where the schedule has been significantly shortened). From the shareholder perspective, acceleration reduces future expected returns on investment, since shareholder capital will be deployed over a shorter period.

If cost recovery is not accelerated and stretches out after the plant is closed, customers will eventually be paying depreciation expenses, interest on debt, and an equity return for an asset from which they no longer receive any benefits. Indeed, some future customers will likely wind up paying for an asset that never served them.

Regardless of how depreciation is treated, early retirement of generation assets can lead to economic dislocation for power plant workers and adjacent communities due to lost wages and a reduced tax base for funding services. Here, too, the tools of traditional cost-of-service regulation do not provide an easy way to balance the interests of plant communities, current and future customers, and utility investors.

Ratepayer-backed bond securitization ("securitization") is a financing tool that has been utilized for decades in the U.S. to mitigate costs for customers and risks for utilities and their shareholders. Securitization is now available to address the challenges of early coal plant retirement, for example in Michigan, where older legislation already allowed the approach and Consumers Energy has issued bonds for this purpose, and Colorado, New Mexico and Montana, where new laws authorizing it have passed within the last two years. Given suitable financial characteristics of the old asset and the new bond, securitization can reduce ratepayer costs, protect shareholders, and even allow for transition assistance for dislocated workers and communities.

Minnesota Power, an operating division of ALLETE, and Rocky Mountain Institute (RMI) are collaborating to assess the feasibility of using ratepayer-backed bond securitization in the North Star State.

This report will address compliance requirements made by the Minnesota Public Utilities Commission (Commission) in three Minnesota Power Dockets: 1) the 2016 rate case (Docket E015/GR-16-664); 2) the most recent Integrated Resource Plan (Docket E015/RP-15-690); and 3) the Energy Forward Resource Plan (Docket E015/AI-17-568). On September 25, 2020, the Commission ordered that by October 1, 2020, Minnesota Power shall file a report on securitization informed by the input of stakeholders including the Office of Attorney General and the Clean Energy Organizations. The report should include, at a minimum: a description of how securitization could be used to facilitate the closure of facilities with large undepreciated balances; discussion of the feasibility of securitization in Minnesota and for Minnesota Power; specific discussion of the obstacles to securitization and how they can be resolved; and discussion of how securitization could be used to balance the interests of ratepayers and shareholders as they apply to Boswell Energy Center (Boswell).

This report, developed with the input of stakeholders, presents the results of Phase 1 of the feasibility study. Specifically, it

- describes and quantifies the opportunities and challenges for Minnesota Power in utilizing securitization to address unrecovered costs, with the degree of challenge largely flowing from the company's relatively small size and high historical revenue volatility;
- compares Minnesota Power with 45 utilities that have used securitization and provides three case studies of utilities that have used securitization, including two "peers" close in size to Minnesota Power; and
- identifies policy, regulatory, and financial structuring options for securitization to mitigate challenges of particular relevance for Minnesota Power.

Phase 2 will dive deeper into quantitative modeling to assess the potential financial impacts of securitization on current and future customers of Minnesota Power as well as on the utility's investors; this deep dive will consider scenario analysis of the policy, regulatory, and financial structuring options identified in this report. The modeling analysis will be informed by the baseload retirement study and integrated resource planning that Minnesota Power will be filing in parallel.

Note that this report does not investigate the merits of early closure of Boswell units and does not evaluate the cost impacts of replacement power in discussing the benefits of securitization. That analysis will be included in the baseload retirement study. Rather, this report considers how securitization could be used to mitigate potential customer impacts in the event of an early Boswell closure.

Chapter 2. Securitization Overview: Mechanisms, Use Cases and Risk Assessment

Ratepayer-backed bond securitization allows utility customers to benefit from low-cost bond financing raised on the basis of a pledge of future revenues from a dedicated surcharge on their bills. The low cost of debt is made possible through legislation at the state level that provides bondholders significant protections and assurances that those future revenues will be sufficient to cover future debt service obligations. For example, a rate-regulated tariff on a power plant is generally sized to allow for recovery of expected annual fuel and operating costs as well as of past investment in the plant made by its owner, along with an administratively set return on the unrecovered investment balance over the life of the plant. The tariff also generally includes provisions to allow accumulation of a reserve to cover expected future plant decommissioning costs net of salvage value. If the plant is retired before the end of its accounting life, then the owner is generally able to continue to recover historical investments and a return on unrecovered capital through tariffs. Securitization allows customers to benefit from the refinancing of that obligation to reduce financing costs from a higher return on utility capital (including higher-cost equity as well as debt) to lower-cost securitized debt. Many customers will likely already be familiar with the value of refinancing to reduce costs, for example from experience with refinancing home mortgages or consumer finance products.

If legislation allows, the size of the bond may also be increased to provide financing for other needs, such as plant community transition assistance.

This Phase 1 report begins with a conceptual overview of how securitization impacts customer and utility interests compared to traditional utility financing. We then turn to a description of the mechanics of how securitization works, paying significant attention to major risks and challenges to effective implementation. Next, we provide historical context around the use of securitization and discuss the main concerns and metrics evaluated by credit ratings agencies in rating securitization bonds. Finally, we identify and assess the key utility financial metrics that are relevant to the successful use of securitization to achieve customer cost reductions.

Securitization is a tool that may lower customer costs by refinancing utility debt and equity with lower-cost debt

The early phase-out of older power plants can heighten ratemaking incentive conflicts between utility shareholders and customers. When a plant is retired prior to its scheduled decommissioning date, there is often an unrecovered capital balance left in the customer rate base. Utilities expect to recover the capital balance and earn their allowed rate of return on the capital balance outstanding.

One option for recovering the capital balance is maintaining the original depreciation schedule upon early retirement by the use of deferred accounting. This option ensures that investors earn the rate of return previously approved by regulators and eliminates the rate shock that can occur from accelerated depreciation. However, it leaves customers paying a full utility return on capital on an asset that is no longer operating. Accelerated depreciation shortens the timeframe to recover the outstanding capital balance, but it can drive a near-term increase in the revenue requirement, burdening all customers.

There is no win-win solution to this incentive conflict within the framework of traditional utility finance. Shareholders may agree to accept a reduced return on equity capital, but this step could cause investors to demand higher returns in the future. Nevertheless, ratepayers will still be paying some level of equity return for an asset that is no longer in service.

Ratepayer-backed bond securitization is designed to reduce customer costs and address shareholder risks associated with accelerating plant phase-out prior to a utility achieving full cost recovery. There is no need to determine an appropriate equity return for a non-operating plant, while shareholders get their capital back immediately so that they may reinvest in new assets in keeping with their chosen risk-return expectations.

Securitization can save customers money by allowing them to benefit from lower costs of refinancing utility debt and equity on the remaining balance of the retired plant solely with low-cost (2-4%) debt. With traditional utility financing, utilities are paying (both debt and equity) investors a combined after-tax return of 6-8%, compensating them for the utility's financial and operating risks. From the customer perspective, the equity component of this return must be paid on a grossed-up, pre-tax basis, resulting in an effective "cost of capital" reflected in rates on utility financed assets that can be between 8-11%.

Table 1. Summary of Transition Mechanisms

Mechanism	Description	Impact on Utilities	Impact on Ratepayers
Regulatory asset with early retirement / Traditional utility finance	Undepreciated plant balance is amortized after plant retirement	Recovery of capital with regulated return on balance, but there may be increased stakeholder pressure for disallowance	Pay regulatory return on asset that is no longer operating
Disallowance	Utilities not allowed to earn return on retired assets (either full or partial)	Loss of disallowed capital and the return thereupon. Potential adverse impact on company's ability to raise future equity and on its credit rating	Relieved of obligation to repay disallowed capital and return thereupon. Potential increase to future cost of capital for utility projects
Accelerated depreciation	Reduce the depreciation period to eliminate balance by retirement	Recovery of capital	Near-term rate increase
Reduced allowed return	Reduced return to shareholders	Partial loss of earnings. Equity capital remains deployed but delivers less than expected return. Potential adverse impact on company's ability to raise future equity and on its credit rating	Financing costs are reduced, though still contain an equity component. Potential increase to future cost of capital for utility projects
Securitization	Refinancing of outstanding balance solely with highly rated, low-cost debt, over tenors at least as long as the plant's pre-retirement depreciation schedule	Capital is returned immediately. Equity earnings opportunity is forfeited, but capital is available for recycling or for return to shareholders for other investment opportunities	Low-cost financing delivers savings to ratepayers. Long tenors do shift cost to future ratepayers, but that group may derive benefits from a financing tool that can facilitate a more rapid transition to clean energy

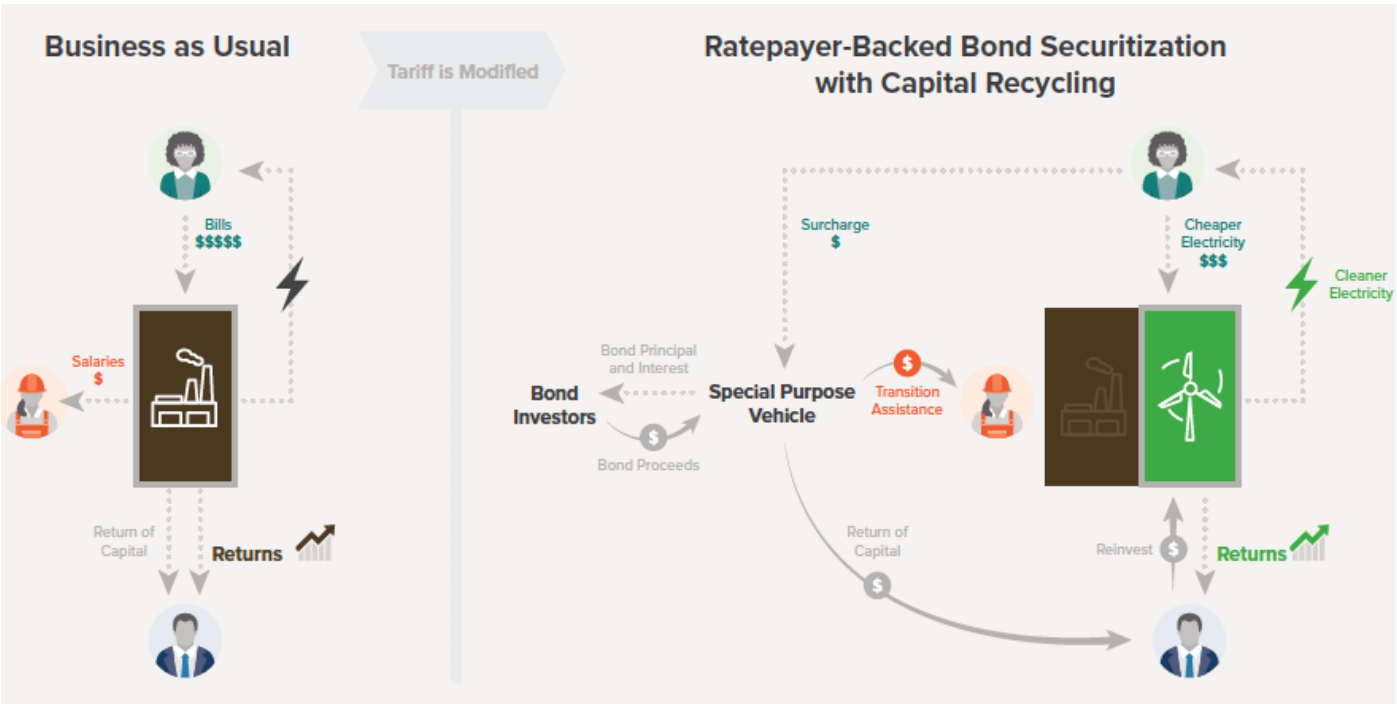
To date, two companies have used securitization to provide cost recovery for generation assets retired prior to the end of their depreciable lives, and additional companies are currently pursuing securitization for this purpose. Duke Energy Florida securitized $1.3 billion in unrecovered costs associated with accelerated retirement of a nuclear asset in 2016, and Consumers Energy securitized $378 million in unrecovered costs associated with the accelerated retirement of a portfolio of coal and gas units in 2014. More recently, in New Mexico, the Energy Transition Act passed in 2019 authorized the regulated utility PNM to use securitization to refinance $361 million in costs associated with the early retirement of the 497 MW coal plant, San Juan Generating Station. The proceeds from securitization will be used to provide recovery of $283 million in undepreciated investments, $9 million in securitization transaction costs, $29 million in decommissioning and reclamation activities, and $40 million in assistance for affected coal plant and mine workers and their communities during the transition. Further, the state regulator recently approved a replacement portfolio of nearly 1 GW of solar, wind, and storage (some of which will be owned by PNM) to be located in the counties that had hosted the plants and mines. These actions together are estimated to save residential customers $7/month by the time the transition is complete in 2023.[i] Finally, we note that WEC has recently submitted an application for a financing order for approval to issue $118 million in securitization bonds to provide cost recovery for pollution control equipment for accelerated retirement of the Pleasant Prairie coal plant,[ii] and Consumers Energy has submitted a financing order for approval to securitize an additional $703 million of unrecovered coal investment costs associated with the retirement of units 1 and 2 of its D.E. Karn plant.[iii]

How securitization works in practice

In a state in which securitization has been authorized by legislation, a utility can submit an application to the state utility regulator for approval of a financing order to execute a securitization transaction. If the regulator issues such a financing order, a special purpose vehicle is set up and issues a bond whose proceeds can be used to cover (depending on the allowed uses authorized in legislation) any unrecovered costs, expected plant decommissioning costs net of salvage, and/or transition assistance. The bond is repaid through a surcharge on customer bills authorized by the financing order.

Customers benefit by trading lower flexibility in future rates for reduced current and future costs: The rights to future revenues from the surcharge are not available to the utility or to the customers for any other purpose, but are instead owned – as a property right – by the special purpose entity and are used exclusively to repay bond investors and cover any ongoing securitization administrative costs. Further, as we discuss in greater detail below, authorizing legislation requires that the surcharge be non-bypassable, irrevocable, and adjusted automatically (via a periodic true-up mechanism aligned with debt service schedules) to collect the revenues required for debt service, no more and no less. These protections taken together mean that any future regulation, legislation, or litigation that attempts to reduce or avoid repayment can expect a strong legal defense from bondholders who can invoke the takings clause of the Fifth Amendment to the U.S. Constitution to receive just compensation. As a result, customers and regulators trade reduced flexibility in determining future rates in return for the lower financing costs charged by bondholders due to the lower risks of losses they face. The reduced flexibility will be apparent in future rate case proceedings, where rate design proposals will need to consider the surcharge amount when determining the all-in impact of a rate change on customer bills.

Figure 1. How Ratepayer-Backed Bond Securitization Works



Securitization savings manifest in rates as the difference between the avoided rate impact of recovering capital using traditional utility finance and the surcharge: When a securitization transaction is executed, the utility receives the proceeds from the bond issuance net of any transaction costs incurred (which will be discussed in greater detail in Phase 2) and any amounts authorized to be used for other purposes (e.g., transition assistance for affected workers and communities). From a ratemaking perspective, the proceeds transferred to the utility, net of decommissioning costs net of salvage, are deducted from the utility's rate base. Revenues required (and, thus, rates) are adjusted to reduce collections previously authorized to provide return of, and on, the capital removed from rate base. Tax expenses for nondeductible revenue amounts are also reduced. Any accumulated deferred income taxes (ADIT) associated with the physical asset remain as an offset to rate base and must be normalized; if the physical asset is no longer operational, amortization of the ADIT occurs in line with principal amortization of the securitization bond. In sum, securitization savings to customers arise from reductions in the revenue requirement net of the cost of the surcharge. Generally, legislation requires that securitization only be undertaken if the associated savings are positive both in the near term and on a net present value basis over future years.

The distribution of savings among ratepayers depends on both the current allocation of unrecovered costs among ratepayer classes and the design of the surcharge: An important consideration in the design and execution of a securitization transaction is to assess quantitatively any potential shift in costs between ratepayer classes that may result from the combination of the reduction in rates associated with the removal of unrecovered capital costs from rates and the imposition of the surcharge. If the return of and on unrecovered capital costs is distributed among ratepayer classes differently than the anticipated distribution of the surcharge, such a shift in costs can occur. We discuss in chapter 4 various approaches to designing the surcharge to mitigate this potential cost shift.

Securitization can be timed, sized, and executed independently of asset retirement: The "asset" being securitized has nothing to do with any physical asset: strictly speaking, it is the future revenue stream from the surcharge (which has been pledged to bondholders and is not available to cover other future costs). Therefore, securitization does not result in any transfer of physical property even when it is used to address unrecovered costs from accelerated plant retirement, as it is purely a financial transaction to cover anticipated future customer regulatory obligations. As a purely financial transaction, securitization does not need to be either sized or timed to coincide with plant retirement; rather, it can be used before or after plant retirement to cover some or all allowed costs, as long as such options are explicitly permitted for the use of proceeds in state securitization legislation.

Community transition risks can be mitigated using securitization: If the authorizing statute permits, the state regulator and utility can use securitization to finance up-front transition assistance to offset the near-term challenges faced by the communities that hosted the generation assets being retired. The size of the transition challenge – both the scale of lost wages and potential holes in local tax revenues – is generally proportional to the unrecovered costs,[iv] which in turn are tied to the financing cost savings achievable. Increasing the size of the bond issuance to provide funds for transition assistance will raise customer costs, in effect netting against some portion of the refinancing savings provided by the securitization. One way to balance stakeholder interests is to size transition assistance as a portion of the potential savings, for instance capping it at 15% of the savings. This approach can provide meaningful resources to affected communities and workers in a timely fashion, while still delivering net savings to the customer population as a whole.

Securitization can achieve low financing costs without burdening state, local, or utility credit ratings: If the securitization transaction is structured to achieve a high enough bond rating (which we will discuss further in the following sections), bond interest rates can be as low as 2-4% depending on the term of the bond. Capital cost savings are maximized when the bonds gets a AAA rating – and of the $50 billion in utility securitization transactions that have occurred, only one relatively small issuance has failed to achieve this rating from all the major credit rating agencies.[v] Note that securitization is not considered either a state or municipal obligation. It therefore does not impact the credit rating of any state or municipal entity, nor is it backed by the full faith and credit of any government entity. However, securitization does benefit from credit protections afforded by legislative and regulatory action.

Securitization can mitigate many (but not all) transition costs and risks – but it can also introduce new challenges and risks that need to be efficiently managed to deliver on its promise

Securitization reduces the rate impact of demand shocks and downturns by lowering fixed revenue obligations, but it also limits regulatory flexibility to delay or disallow those obligations: While customers and regulators give up some flexibility in determining future rates by using securitization, they benefit from reduced overall revenues required. To the extent that a future rate shock is driven by reduced expected overall collections due to reduced consumption or customer base, the rate impact of the shock is always proportional to total revenues required to be collected in rates. Since securitization reduces these total revenues required, its use always reduces the impact of such a shock to first approximation. In the absence of securitization, however, a regulator has greater flexibility to delay or disallow cost recovery to mitigate the impact of such a rate shock, precisely because securitization legislation typically includes protections for bondholders that support AAA credit ratings. Since delay and disallowance can have significant negative financial implications for utilities (and therefore, for financing costs for future customer needs), they are not frequently employed. Hence, securitization generally – but not always – mitigates rate volatility arising from economic shocks.

Securitization in isolation is mildly credit positive for utilities, but reduces expected future earnings: The securitization transaction results in an infusion of liquidity to the utility, which reduces utility credit risk in the near term – and, as it provides immediate cost recovery, obviates the risk of disallowance of the balances recovered. However, the increased liquidity and cost recovery come at the expense of future cash flows and earnings that would have been generated by the unrecovered costs if they had remained in rate base. As securitization is executed using a special purpose vehicle, it is not considered utility corporate debt and doesn't directly impact the balance sheet of the utility (though rating agencies generally calculate credit metrics both with and without consolidating securitization bonds). As a result of these generally credit-supportive features, securitization on its own is usually regarded as mildly credit positive by rating agencies.

The liquidity infusion reduces the utility's net debt, but does not directly require the utility to buy back any debt or equity: In theory, the securitization transaction in isolation would result in an infusion of liquidity that reduces its long-term assets while increasing its cash and current assets by an amount equal to the proceeds from securitization allocated to the utility. As a result, securitization does reduce the net debt (debt net of liquid assets) of a utility. As an off-balance sheet debt financing, however, it does not directly impact utility liabilities. Therefore, securitization on its own does not immediately require a reduction of the utility's long-term debt or equity, which may not be attractive if the utility's bonds are not callable and/or require significant make-whole payments. However, utilities are required to maintain an approved capital structure, and this factor must be considered.

Utility reinvestment ("capital recycling") of the liquidity infusion from securitization into renewable assets may be accretive to utility earnings – but introduces tax, timing, and regulatory risks: An attractive option for utility investors may be to see the capital returned to the utility by the issuance of securitization bonds subsequently invested in new utility-owned renewable energy assets ("capital recycling"). Because of their different operating characteristics, renewable assets may require significant additions to rate base beyond the recycled capital. These new assets may include additional investments to ensure system reliability to replace the retired assets, such as additional transmission investment. The new assets are likely to have a lifespan longer than was expected for the old asset before it was deemed suitable for early retirement. When these total costs are below the long-run marginal costs (fuel, operating expenses, and any maintenance capital expenditures) of existing assets, the aggregated effects of the securitization and replacement should be (at least in current capital market conditions) earnings accretive and credit neutral to positive, providing a longer-term source of earnings while also delivering cleaner electricity to customers. However, the realization of this spectrum of benefits is contingent upon planning, procurement, and rate regulatory processes that introduce reinvestment timing and regulatory process uncertainty risks for the utility. Furthermore, since the economics are premised on rapid deployment with efficient monetization of renewable and storage tax incentives prior to their phase out, timing and tax position constitute key risks areas. We will discuss these issues in more detail using quantitative examples in our Phase 2 report.

Customers could see additional savings from economic replacement: If the all-in volumetrically defined costs of a renewable replacement asset – the levelized cost of energy (LCOE) – plus the additional costs of investments required to ensure system reliability are below the long-run marginal costs (fuel, operating expenses, and any maintenance capital expenditures) of the old asset, further savings beyond those from securitization can be delivered to ratepayers. Federal tax incentives and their regulatory treatment in ratemaking can play a significant role in determining the existence and size of these savings, as well as their distribution between customers today and in the future. Even if the all-in cost of new generation exceeds the retired plant's operating costs, securitization savings may still be sufficient to deliver a net benefit to ratepayers (i.e., if those savings exceed the overhang of the new asset's LCOE and the cost of the additional investments relative to the retired plant's avoided operating costs). Detailed analysis is required to determine overall ratepayer impacts of securitization (including transition assistance, if applicable) in combination with replacement assets and related reliability investments; this evaluation will be undertaken in Phase 2, based on inputs from Minnesota Power's concurrent planning and retirement studies.

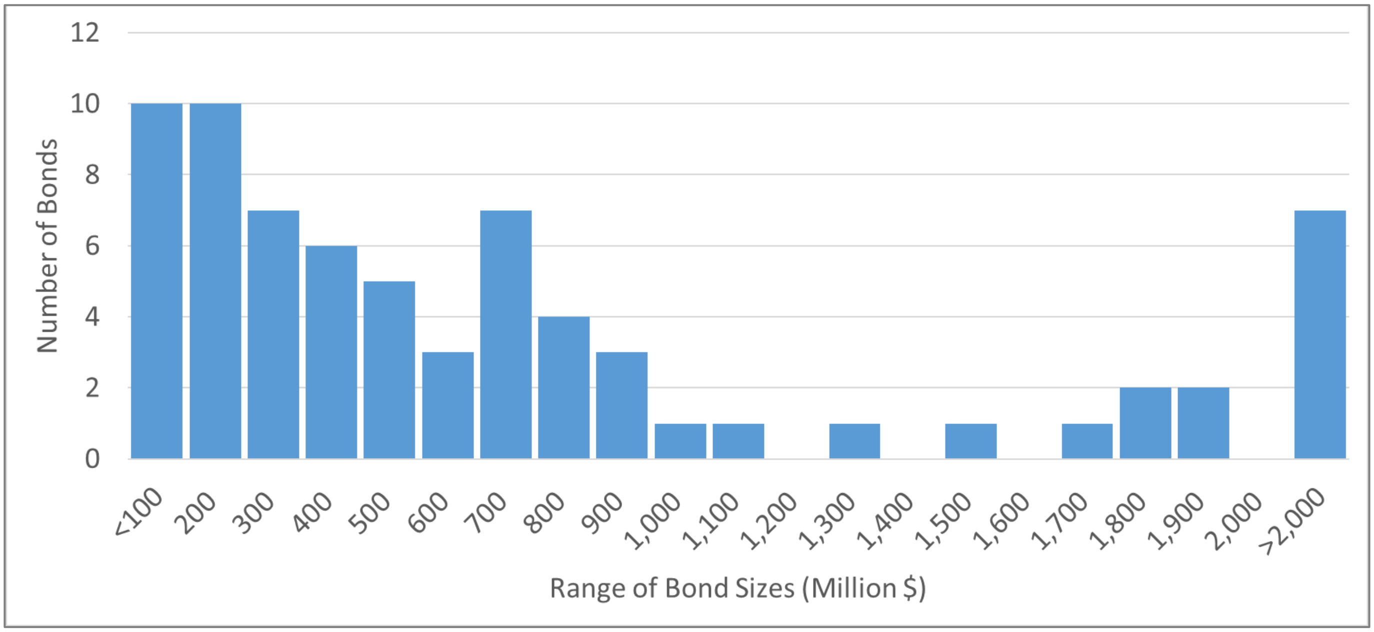
Comprehensive and coordinated resource and financial planning, including consideration of securitization, can help mitigate transition risks and maximize benefits to customers: A comprehensive planning exercise that includes integrated resource planning along with financial analysis of tools like securitization for early asset retirement can support a transition to a cleaner electricity system. Such an effort can identify portfolios of resources that can deliver necessary energy, capacity, and ancillary services at the least cost to customers. Timing and regulatory risks associated with this transition can be further mitigated if the planning process is followed by coordinated execution of both resource procurement and financing proceedings. Finally, coordination of financial planning with resource planning can reduce execution risks of a potential securitization transaction by providing flexibility in timing to take advantage of favorable capital market conditions so as to deliver the lowest costs to customers.

Securitization has been used for utility transition in the last three decades, and coal plant retirement cost refinancing is an emerging use of proceeds

Securitization was used repeatedly in the late 1990s and early 2000s by utilities in regions that went through restructuring to competitive wholesale markets in order to recover stranded generation costs of assets transitioning out of the cost-of-service regime. Appendix A provides an overview of all identified securitization transactions by investor-owned utilities since the mid-1990s, categorized by use of proceeds. Table 1 in Appendix A is a break-out of the transactions specifically related to restructuring. Table 2 in Appendix A describes transactions related to storm cost recovery. Table 3 in Appendix A covers other transactions, including those for retirement and recovery not related to restructing.

Figure 1 in Appendix A arranges the historical securitization bonds identified by total issuance size. Figure 2 below provides a distribution of those same bonds by issuance size. There is clearly a wide range of bond sizes, and several utilities, such as PG&E and PPL Electric Utilities, have issued more than one bond over the years. Minnesota Power's unrecovered plant balance (roughly $780 million) would potentially put an issuance among the top 30% of utility securitization bonds by issuance size, if the entire balance were recovered through one bond.

Figure 2. Securitization Bond Size Distribution



Data source and notes: Original data from Saber Partners, with additional information collected by RMI team through S&P Market Intelligence platform. *https://saberpartners.com/list-of-investor-owned-utility-securitization-rocrrb-bond-transactions-1997-present/*

When assessing a securitization transaction, credit rating agencies look for factors that provide legal and regulatory stability of future revenue streams

The use of securitization must balance benefits to consumers and the utility against risks to securitization bondholders as well as any potential securitization-related risks to the company's other lenders and investors. While the major credit rating agencies – Moody's, Standard & Poor's (S&P), and Fitch Ratings – have different frameworks to assess the risks associated with the use of securitization, these frameworks generally include the following key factors:

1) Legal and regulatory stability

This factor refers to the risks associated with the legislative and regulatory changes in the utility jurisdiction and its impact on the securitization bonds. The legal and regulatory risks can be mitigated through careful design of the legislative statute and financing order. Fitch Ratings identifies seven key legal/regulatory aspects of a securitization statute that should be evaluated:[vi]

- **property right** status of the "future special tariff collections…that can be transferred and pledged as a security interest";
- **irrevocability and state support** "prohibit[ing] the legislature, the commission or any other agency or governmental entity from rescinding, altering or amending the special tariffs or property rights in any way that would reduce or impair their value";
- **bankruptcy remoteness/true sale** "to protect bondholders from the interruption or impairment of cash flows in the event of a utility bankruptcy…[and] to provide that the transfer of property

rights to the trust will be treated as an absolute transfer, not as a pledge, of the seller's right to, title to and interest in the property";

- **utility successor requirements** so that "any successor to the utility (including, but not limited to, the utility as debtor-in-possession and the reorganized utility after bankruptcy) [will] be treated as a successor (for purposes of imposition of special tariffs on the successor's customers) and be ordered to continue servicing the tariff bonds to avoid disruption in billing and collecting";
- **third-party energy providers** that provide consolidated billing must submit to the "imposition by the state, authority or equivalent agency of the state of minimum credit quality or collateral requirements on parties wishing to assume this service";
- **true-up mechanism** that reviews and adjusts the special tariff on at least an annual basis "to a level sufficient to ensure that the periodic bond payment requirements (PBPRs) (interest payments, scheduled principal amortization, related fees and any replenishment of any [credit enhancement] balances) are met"; and
- **Nonbypassability** protecting the utility's monopoly of the distribution network so that it can collect the special tariff "from all existing retail customers and all future retail customers within the service territory without any (or with a few) exceptions."

It is worth emphasizing the importance of the true-up mechanism, which provides significant protection to bondholders against volatility in customer collections. Nevertheless, excessive volatility that leads to surcharges becoming a significantly large fraction of customer bills can lead to additional regulatory and legislative risks. Thus, in some cases, it may be helpful to consider additional credit enhancement mechanisms, as we discuss below.

2) Rate design and revenue stability

Rates that are designed to promote revenue stability – that allow for timely recovery of utility capital and operating costs while balancing the interests of all impacted stakeholders and, further, providing flexibility to recover unexpected costs – offer the best environment for the use of securitization.

The breakdown of residential, commercial and industrial customer revenue is a key factor that credit analysts take into consideration as they assess revenue stability. Both Moody's and Fitch have highlighted as a risk the potential for shifts to "self-generation or adoption of alternate energy sources" by large C&I customers if energy prices increase.[vii]

To mitigate the risks associated with high C&I concentration, all three credit rating agencies evaluate credit enhancements, including the true-up mechanism as well as "reserve accounts or subordinated tranches" when true-up is not in place.[viii] The true-up mechanism is particularly valued for providing "cross-collateralization" where all customer classes bear responsibility through the true-up to pay in full the securitized special tariffs.[ix]

However, true-up mechanisms can introduce potential risks if the total amount of the revenue adjustment with cross subsidization is so large that the certain customers classes might cut back on electricity usage or experience increases in delinquencies and charge-offs. Interviews with credit analysts revealed concern that if the true-up mechanism leads to a much higher surcharge for certain customer classes, there could be political pressure from state regulators to enforce higher regulatory scrutiny on utility rate design. And even though securitization legislation designed to achieve a high credit rating typically includes a pledge by the state not to impair the utility's right to collect the surcharges, utilities and bondholders can still potentially face legal challenges from other parties.

One way to control the impact of true-up mechanisms is to limit the size of the securitization bonds relative to total revenues collected. The three major credit rating agencies have different levels of specificity and preferences when it comes to determining the "maximum" size of the bonds.

Fitch Ratings puts the heaviest emphasis on relative size and is the only one of the three major agencies that specifies a threshold of bond payments relative to customer bills. Its rating methodology document notes that "Fitch believes that special tariffs (under all scenarios) in excess of 20% of the customer bill over a long financing term would generally be inconsistent with a 'AAA' rating. In circumstances where the special tariff exceeds the 20% threshold, the likelihood of full principal payment by the legal final maturity would not be consistent with a 'AAA' rating."[x]

Moody's also highlights the importance of stress-testing the percentage threshold in scenario analysis. Its rating document notes that "To obtain a high rating, we would expect that even in a stressful environment, such as one in which energy usage declined dramatically, the charge per customer necessary to pay off the bonds would be reasonably low both in absolute terms and as a percentage of the customer's energy bill. The specific stresses that we place on the variables are issuer-specific and determined on a case-by-case basis."[xi] In interviews, Moody's credit analysts emphasized that, rather than drawing a hard line, they focus on how high the percentages could go in the worst scenarios, and whether any measures to mitigate such risks are in place.

S&P doesn't specify a threshold. In interviews, S&P credit analysts suggested that as long as the economic fundamentals within the utility's service territory are sound, the associated business risks are manageable ("bill affordability"), and the dynamics between utilities and regulators are healthy enough to ensure the regulatory risks are manageable, S&P will not put a hard limit on the size of a securitization or, as the analysts stated, "over-penalize the utilities."[xii]

Chapter 3. Securitization and Minnesota Power: Financial Opportunities and Challenges

In this section, we describe and quantify specific financial opportunities where Minnesota Power might make use of securitization to address unrecovered costs, as well as the barriers and challenges it could potentially face in doing so. We begin by identifying the unrecovered balances associated with Minnesota Power's operating and retired coal units. Then, we assess potential risks to bond investors stemming from the utility's high concentration of C&I customers, its historical revenue volatility, and its small size; these may make it challenging for Minnesota Power to avoid increasing risk to its corporate bondholders while simultaneously achieving the highest possible credit rating – and hence, the lowest possible cost of debt – for a securitization issuance. Finally, we present three brief case studies on the use of securitization by other utilities (two "peers" close in size to Minnesota Power). These comparative analyses show that securitization has been successfully utilized by other utilities facing some of the challenges similar to those faced by Minnesota Power.

Minnesota Power has two operating coal units and roughly $784 million in historical coal plant costs scheduled to be recovered over the next 15 years

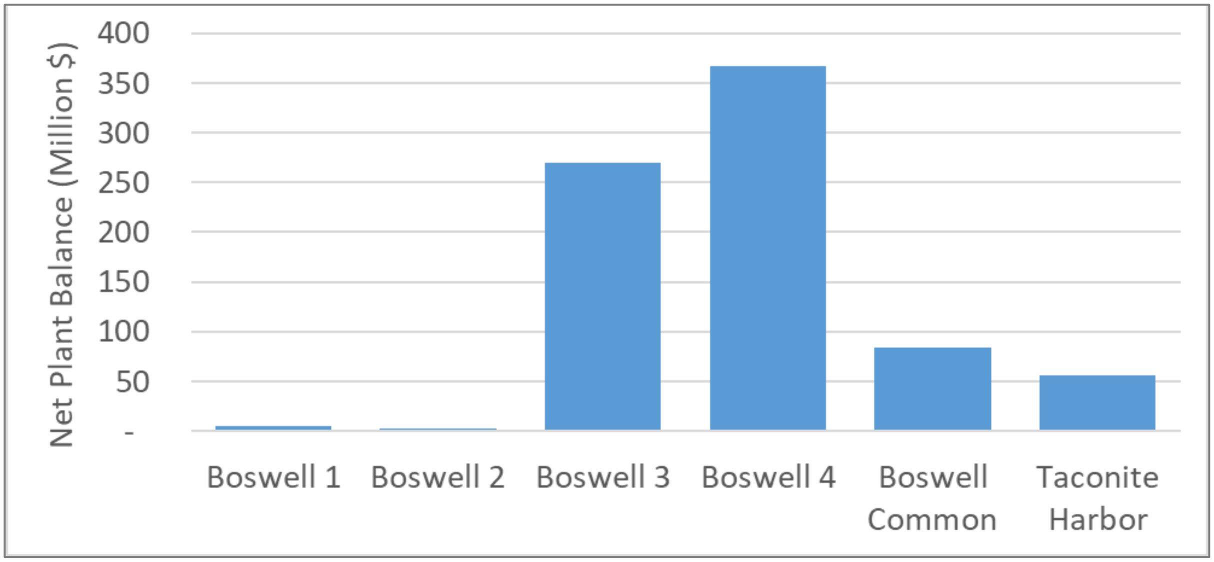
Minnesota Power retired Unit 3 (84MW) of Taconite Harbor Energy Center in 2015 and Units 1 & 2 (68MW each) of Boswell Energy Center in 2018.[xiii] The other two units of Taconite Harbor Energy Center, Units 1 & 2 (75MW each), were idled in 2016.[xiv] The only remaining operating coal units are Boswell Energy Center Unit 3 (355MW) and Unit 4 (468MW owned by Minnesota Power out of 585MW). In 2019, Unit 3 generated 1,571 GWh of electricity, while Unit 4 produced 3,240 GWh.[xv]

Based on the information collected from Minnesota Power's 2016 rate case proceeding (Docket E015/GR-16-664) and discussions with company representatives, we estimate that, as of the beginning of 2020, Minnesota Power's existing and retired coal plants were associated with approximately $784 million of historical investments (plus additional reserve needs to cover expected decommissioning costs net of salvage) in rates and not yet recovered. Figure 3 shows that the two retired Boswell units and the Taconite Harbor units are nearing full cost recovery, while the bulk of the remaining net plant balance is associated with the two operating Boswell units. This net balance is primarily due to recent investments in emission control equipment and new turbine rotors installed to improve the operating efficiency of the units.

Securitization could allow Minnesota Power's customers to benefit from low-cost debt to refinance cost recovery of some or all of the $784 million in net plant balances plus expected decommissioning costs net of salvage currently being recovered in rates. This refinancing can, in principle, be executed at any time. Assuming a 7.5% rate of return and 21% tax rate, we estimate that the current total annual impact of these unrecovered costs on revenues required to be collected from ratepayers (including both the return of and on capital) is roughly $138 million. We can make a simplified estimate of the potential benefit of securitization by assuming that the total balance is refinanced through a 15-year amortized securitization bond issued with a AAA rating (and an assumed interest rate of 3.1%). In this case, the annual payment to be collected for the first year would be $66 million. This yields a rough estimate of potential savings in the first year from securitization of about $72 million.

Measured against $641 million revenue collected from residential, commercial and industrial customers in 2019, the $66 million securitization payments account for 10% of the total customer payments. As we will see in our comparison of historical securitizations executed by other utilities, this is a relatively high fraction. However, it is still far from the 20% threshold that Fitch considers to be the maximum acceptable for a "AAA" rating. Given the ongoing COVID-19 impact crisis, this burden should be tested under several downside scenarios, which we aim to do in Phase 2 of this study. However, as the estimated annual savings ($72 million) are higher than the surcharge ($66 million), it is likely that this transaction could, in aggregate, be viewed as mildly credit positive for the utility.

Figure 3. Minnesota Power Coal Asset Net Plant Balances (as of year-end 2019/beginning of 2020)



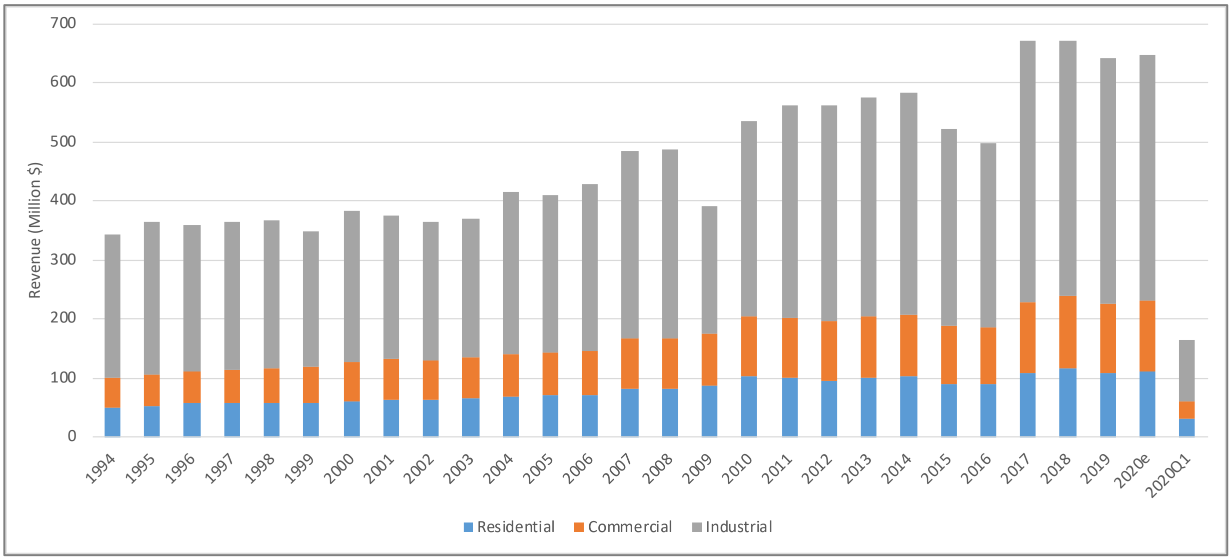
Data Source: Minnesota Power depreciation filing in Docket No. E015/D-20-701.

In Phase 2, the RMI team is planning to conduct a comprehensive analysis to evaluate the revenue requirement impact of these plants as compared with replacement portfolios. We anticipate aligning this analysis with Minnesota Power's upcoming baseload retirement analysis and integrated resource planning modeling.

Minnesota Power's revenue volatility is high due to concentrated customer/revenue base

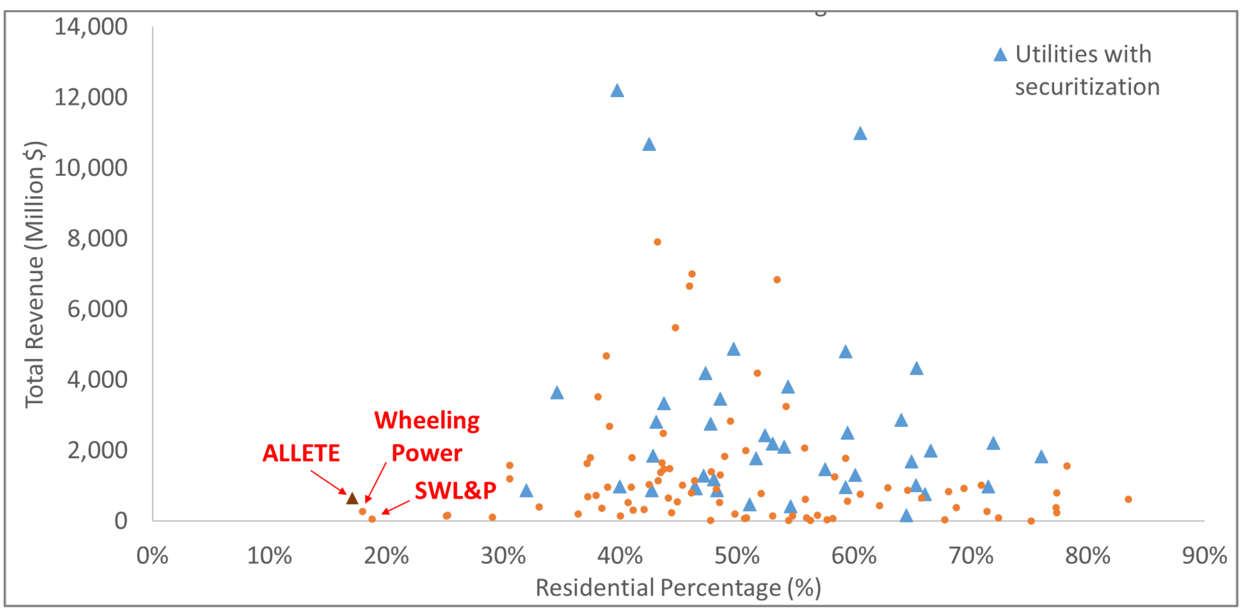
Minnesota Power is exceptional among regulated utilities due to its small size and the high fraction of its revenues – over 80% in each of the last five years – collected from commercial and industrial (C&I) customers. As a result, its revenues tend to be pro-cyclical, varying with economic cycles to a greater degree than most utilities. During the Great Recession of 2008-09, industrial revenues dropped by approximately $100 million – nearly 20% – year over year. As we can see in Figure 4 below, which shows Minnesota Power's historical revenue trends by customer class, volatility has been a persistent issue for the utility. Further, as shown in Figure 5, which compares Minnesota Power's current total revenues and the fraction of its revenues collected from residential customers against other regulated utilities that report to FERC, Minnesota Power is an outlier given its small total size and high fraction of C&I revenues.

Figure 4. Minnesota Power Revenue Breakdown by Customer Class



Data Source and Notes: Minnesota Power and FERC Form 1. This figure and the following analysis include only retail revenues from the residential/commercial/industrial sectors and exclude government/municipals and other reserves/resales.

Figure 5. Total Revenue vs. Residential Percentage for FERC Utilities



Data Source and Notes: RMI analysis of 2019 FERC Form 1 data, including only the 130 of 156 FERC-responding major utilities that reported any residential revenues.

Industrial demand is highly concentrated, amplifying volatility. Minnesota Power's large industrial customers are concentrated in two major energy-intensive industries – taconite/iron mining and paper and other wood production. The revenue collected from power sales to these two industries makes up more than half (56% in 2019) of total revenue. Both industries are themselves highly concentrated among a small number of firms.

Table 2 below lists Large Power (LP) customers from those two industries, covering 6 taconite producing facilities and 4 paper and pulp mills. Those large customers account for approximately 66% of Minnesota Power's retail electricity sales.[xvi] Activity levels at any one of these customers can affect Minnesota Power's total revenue quite significantly. For example, the Keewatin Taconite (Keetac) facility of US Steel (USS) was idle for 22 months beginning from the spring of 2015 through February 2017, driving the decline of total Minnesota Power revenue in 2015 and 2016 and the sharp increase in 2017 shown in Figure 4.

The COVID-19 pandemic has delivered a new blow to Minnesota Power's industrial customers. Several mining plants, including Keetac, were idled due to the pandemic, with more than 1,500 miners laid off at northeastern Minnesota iron ore mines.[xvii] As of the date of this report, two of Minnesota Power's key large industrial customers remain indefinitely idled – Keetac and Verso's Duluth Mill. For context, those two customers used approximately the same amount of energy as Minnesota Power's entire residential customer class in 2019.

Table 2. Minnesota Power Firm Retail LP Customer Contracts as of August 2020

Customer	Industry	Ownership	Earliest Termination Date as of August 1, 2020	Status
ArcelorMittal - Minorca Mine	Taconite	ArcelorMittal S.A.	December 31, 2025	Operating
Hibbing Taconite Co.	Taconite	62.3% ArcelorMittal S.A. 23.0% Cleveland-Cliffs 14.7% USS Corporation	August 31, 2024	Operating
United Taconite and Northshore Mining Babbitt Mine Operations	Taconite	Cleveland-Cliffs	December 31, 2026	Operating
USS Corporation (USS - Minnesota Ore)	Taconite	USS Corporation	August 31, 2024	Minntac – Operating; Keetac Indefinitely Idled
Boise, Inc.	Paper	Packaging Corporation of America	August 31, 2024	Operating
UPM Blandin	Paper	UPM-Kymmene Corporation	December 31, 2029	Operating
Verso Duluth Mill	Paper and Pulp	Verso Corporation	December 31, 2024	Indefinitely Idled
Sappi Cloquet LLC	Paper and Pulp	Sappi Limited	August 31, 2024	Operating
ERP Iron Ore, LLC	Iron concentrate	Plant 2: MJM Minerals Plant 4: N/A	Contract Rejected	Contract Rejected

Data Source and Notes:

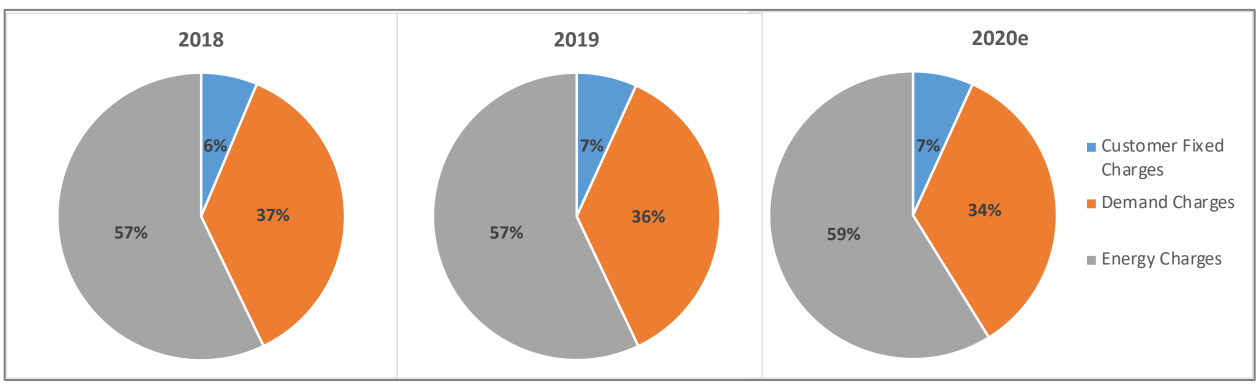
1. *Original Table from Direct Testimony from Frank L. Frederickson before the MN PUC, "Large Power Customer Outlook", In the Matter of the Application of Minnesota Power For Authority to Increase Rates for Electric Utility Service in Minnesota, Docket No. E015/GR-19-442, November 1, 2019.*
2. *The operating status update was provided by Minnesota Power in August 2020.*

3. *4 out of 9 customers were idled in April 2020. Two of them resumed operation in August, while **USS Corporation (USS-Minnesota Ore)** and **Verso Duluth Mill** are still idled indefinitely as of end of August 2020.*
4. *Minnesota Power also has a non-firm retail power supply contract with Silver Bay Power Company, which supplies the Northshore Mining Processing Facility in Silver Bay, MN, and Minnesota Power serves Mesabi Metallics via a wholesale agreement with Nashwauk Public Utilities.*

Minnesota Power's contractual agreements with its large industrial customers are structured such that revenue collection impacts are likely to lag demand reduction. Since most of these agreements are structured as partial take-or-pay contracts, a minimum payment is required even if the plants are idled; thus, total collections are not likely to be affected until customers update their production projections, which for some of the firms listed occurred in August 2020. Indeed, Figure 4 indicates that annualized Q1 revenue is consistent with annual revenue expected for 2020 if COVID-19 had not occurred. However, with two large customers (Keetac and Verso) indefinitely idled, Minnesota Power is now seeing significant revenue impacts from the economic downturn resulting from the COVID-19 pandemic.

Minnesota Power's current rate structure reflects a functional allocation consistent with peer utilities. Over 40% of Minnesota Power's revenues are collected from fixed and demand charges, which tend to be less volatile than energy charges that fluctuate with energy consumption. As shown in Figure 6, these charges have been relatively stable since 2018. This functional allocation of rates is consistent with those of peer utilities, based on the RMI team's interviews with credit analysts. However, it should be noted that most of these fixed charges are collected from a handful of Minnesota Power's large non-investment grade industrial customers.

Figure 6. Minnesota Power Revenue Breakdown by Functional Allocation



Data Source: Minnesota Power.

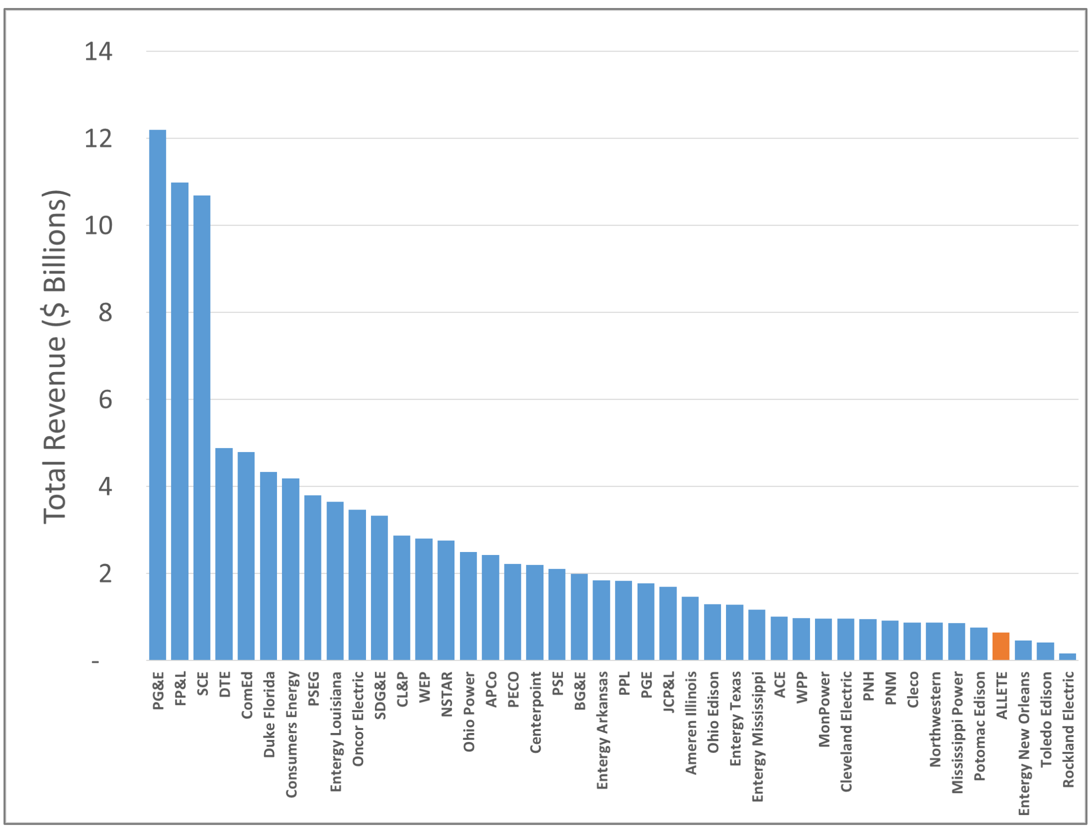
Historical bond issuance data indicate that relative bond size might play a bigger role than revenue volatility when assessing securitization risks for Minnesota Power

In order to benchmark the risks associated with the use of securitization on credit ratings, the RMI team collected historical revenue and rate data for the 42 utilities that have executed securitization transactions, and then summarized the trends for the following three key metrics in three separate figures (Figures 7-9), with Minnesota Power highlighted in orange in each figure:

1) **Utility revenues**, which provide a baseline for customer collections that may be impacted by a surcharge used to repay securitization bonds.
2) **Percentage of revenues collected from residential customers** compared to commercial and industrial. A higher proportion of revenues collected from residential customers suggests that utilities have a more stable customer base, which leads to less revenue volatility.
3) **Historical revenue volatility** from residential, commercial, and industrial sectors. The RMI team collected the historical revenue for each utility and de-trended the data to remove the effect of inflation and rate increases. The final indicator of volatility is the Coefficient of Variation (CV) of the de-trended total revenue for 1994-2019, or whichever years after 1994 for which we have data.

Figure 7 indicates that utilities of all sizes have issued securitization bonds. PG&E, FP&L, and SCE are the largest issuing utilities, each with more than $10 billion in revenues in 2019. On the other hand, more than half of the issuing utilities have total revenues less than $2 billion. However, Minnesota Power stands out as one of the smallest utilities to consider using securitization ($641 million in annual revenues from residential and C&I customers), along with Entergy New Orleans, Toledo Edison Company and Rockland Electric. However, the *absolute* size of a utility as measured by its revenues isn't necessarily the critical metric when it comes to evaluating the capacity for issuing securitization bonds. Rather, it is the *relative* size of the bond's required annual payments compared with revenues that is more important, as we discuss in more detail in the following section.

Figure 7. Comparison of Utility Revenues in 2019

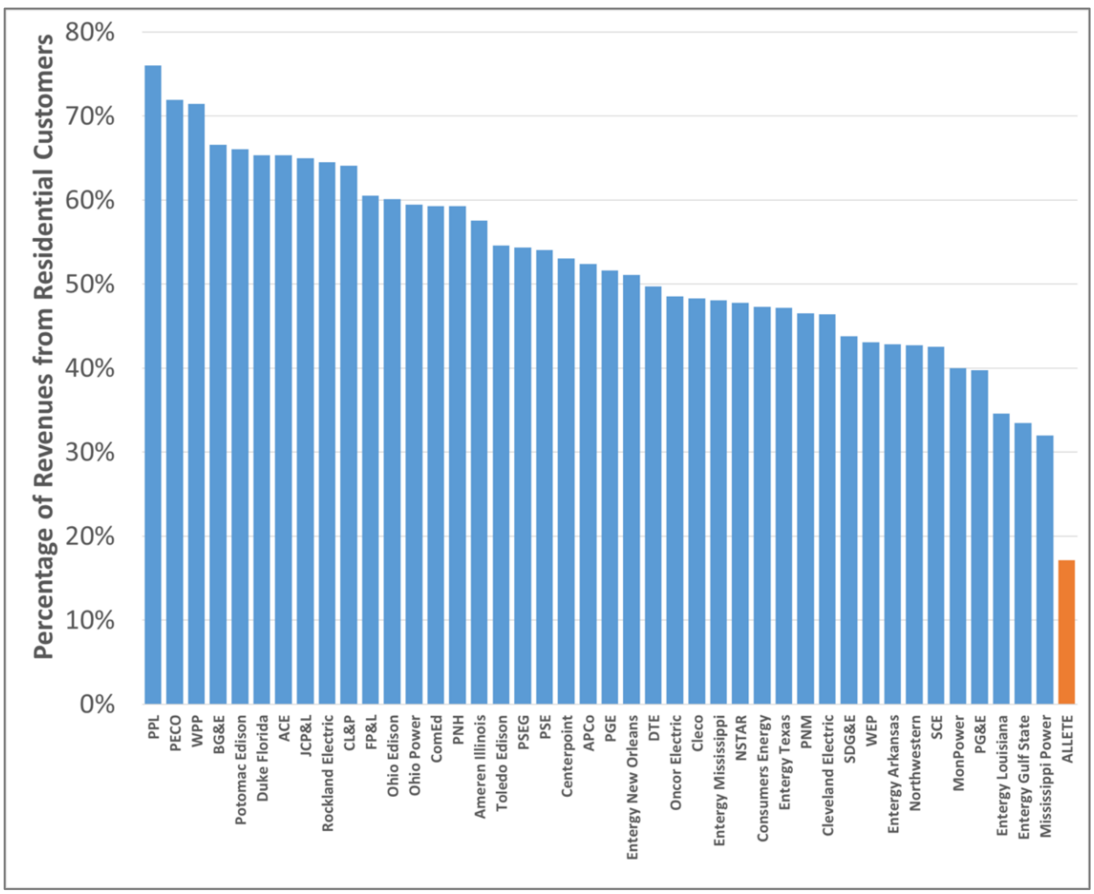


Data Source and Notes: FERC Form 1 2019. Due to the variation in data availability, this chart only includes the retail revenues from residential/commercial/industrial customers. Entergy Gulf States Louisiana, LLC is excluded due to the lack of the 2019 data.

Figure 8 shows that 23 out of the 43 utilities collected more revenue from residential customers than C&I in 2019, which generally indicates more revenue stability, as residential customers are less likely to migrate from one service territory to another or change their consumption behavior significantly in line with economic cycles. Minnesota Power's residential revenue share (17%) is much smaller than that of any utility that has ever used securitization (32% for Mississippi Power Company).

Nevertheless, a high share of residential customers doesn't necessarily guarantee revenue stability. In hurricane-prone areas such as Florida, Louisiana, and the Carolinas, or in wildfire-prone areas like California, revenue risks can be tied to the fraction of customers who never return or business that shut down permanently after a disaster. Credit analysts will take into account locational risks as they evaluate securitization bonds – risks that are rising as climate change increases the likelihood and severity of extreme weather events across the globe.

Figure 8. Comparison of Residential Customer Revenue Percentage in 2019

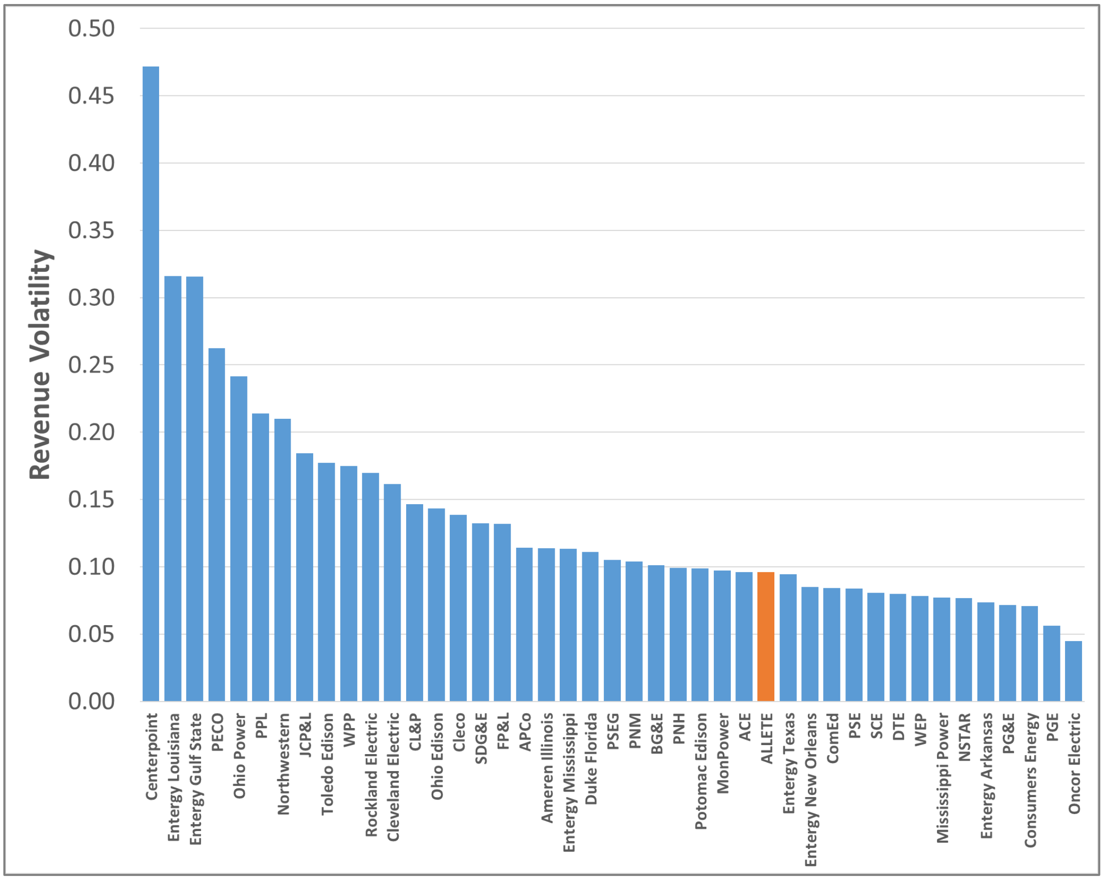


Data Source: FERC Form 1 2019. Entergy Gulf States Louisiana, LLC is based on the last available data from 2015.

Figure 9 shows the Coefficient of Variation (CV) of the de-trended historical annual revenues from residential and C&I customers for the 43 utilities that have used securitization along with the CV for

Minnesota Power. Minnesota Power's revenue volatility does not appear to be as much of an outlier relative to utilities that have successfully used securitization. Several utilities in the Southeast and Southwest, including CenterPoint, Entergy Louisiana, and Texas-New Mexico Power, have seen greater revenue volatility and still successfully executed securitization transactions.

Figure 9. Comparison of Historical Revenue Volatility 1994-2019



Data Source: FERC Form 1 2019. The volatility calculation is based on the data available for each utility, which in some cases could be only for a few years.

Although we have yet to fully uncover the driving forces behind the historical revenue volatility for these utilities, we have done an initial scan to exclude factors that are less relevant to Minnesota Power. Those factors include market restructuring to allow for customer shopping/retail competition, corporate M&A, and changes in services territory reported to FERC. For example, four utilities affected by such factors are Ohio Power Company, Ohio Edison, PECO Energy, and CenterPoint. Ohio Power Company experienced a sharp increase in total energy revenues in 2011 and a gradual decline since then. Ohio Edison and PECO Energy, on the other hand, saw a sharp decline of C&I customer revenues around 2010-2011 that cut total revenue by 40%. CenterPoint saw an 80% cut in revenue in 2002, which can be explained by the market restructuring that took place at the same time.[xviii] PECO[xix] and Ohio Edison[xx] both started to allow for customer shopping in 2010-2011 and saw sharp declines in revenue afterwards. PECO's fluctuation also coincided with the announcement of the merger of its parent company, Exelon, with Constellation Energy Group.[xxi] Ohio Power Company, a subsidiary of American Electric Power Company (AEP), announced its merger with another AEP subsidiary, Columbus Southern

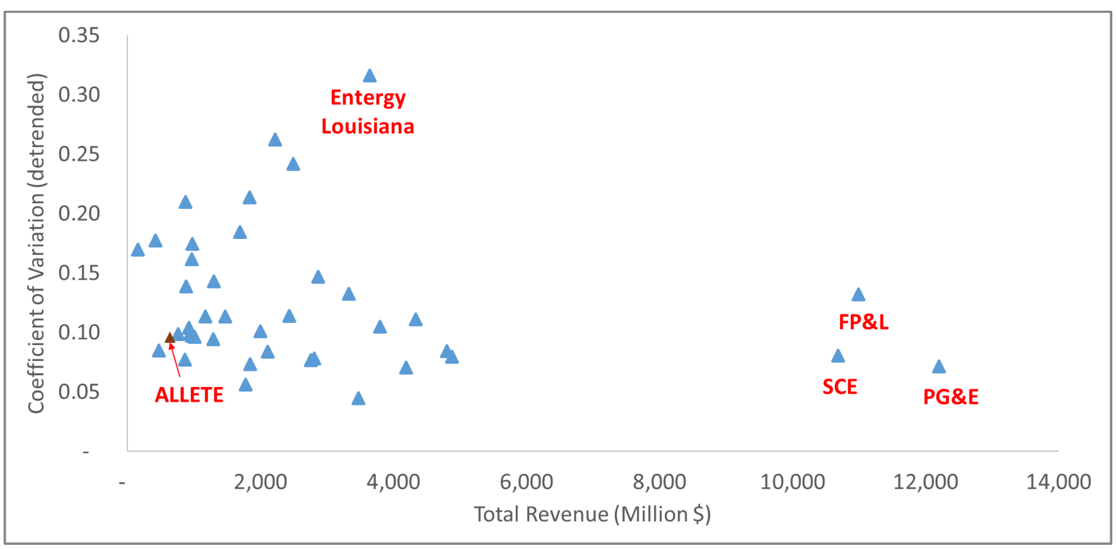
Power Company (CSP)[xxii], which explains the increase in total revenue in 2011. Overall, these are one-off factors not driven by changes in customer consumption, whereas revenue fluctuation for Minnesota Power is mainly driven by economic cycles and their impact on customer activity.

Aside from economic conditions, another driver of cyclical fluctuations is extreme weather events, such as hurricanes and wildfires. After major hurricanes, utilities can see a significant decline in revenue due to the disruption of service and – more severely – migration of customers, and the impact can last for an extended period. Arguably, though, hurricanes and wildfires are less destructive in the mid- and long-run than an economic downturn that permanently shuts down factories and shrinks a customer base. Nonetheless, during our interviews, credit rating analysts emphasized that, when evaluating the risks associated with securitization bonds, historical revenue volatility for both extreme weather events and economic downturns would be considered and assessed using a similar stress-test approach that assumes *permanent* reductions in future revenues similar in size to fluctuations seen in historical data.

Successful utility securitization transactions suggest that volatility, size, and customer concentration concerns may be overcome

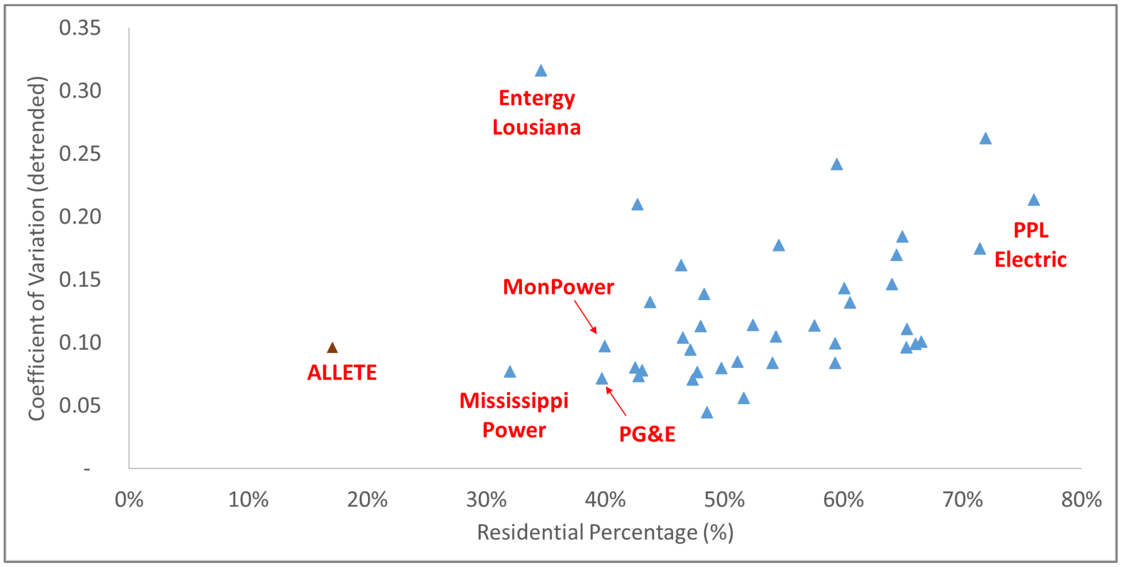
We can combine size, customer class, and volatility information – and compare this data with the expected potential size of a securitization surcharge – to evaluate at a high level whether securitization of unrecovered fossil plant balances by Minnesota Power stands out from a risk prespective relative to historical transactions. Figure 10 plots the revenue volatility metric against total revenue (i.e., size) and Figure 11 plots the revenue volatility metric against the percentage of revenue collected from residential customers; both figures contain labels for Allete and a few outlier utilities. It should be clear from these figures that the small share of residential customer revenue makes Minnesota Power an outlier, but its overall revenue volatility is comparable to other utilities with similar total revenue size.

Figure 10. Revenue Volatility vs. Total Revenue



Note: CenterPoint Energy is excluded because its volatility is the highest but not relevant.

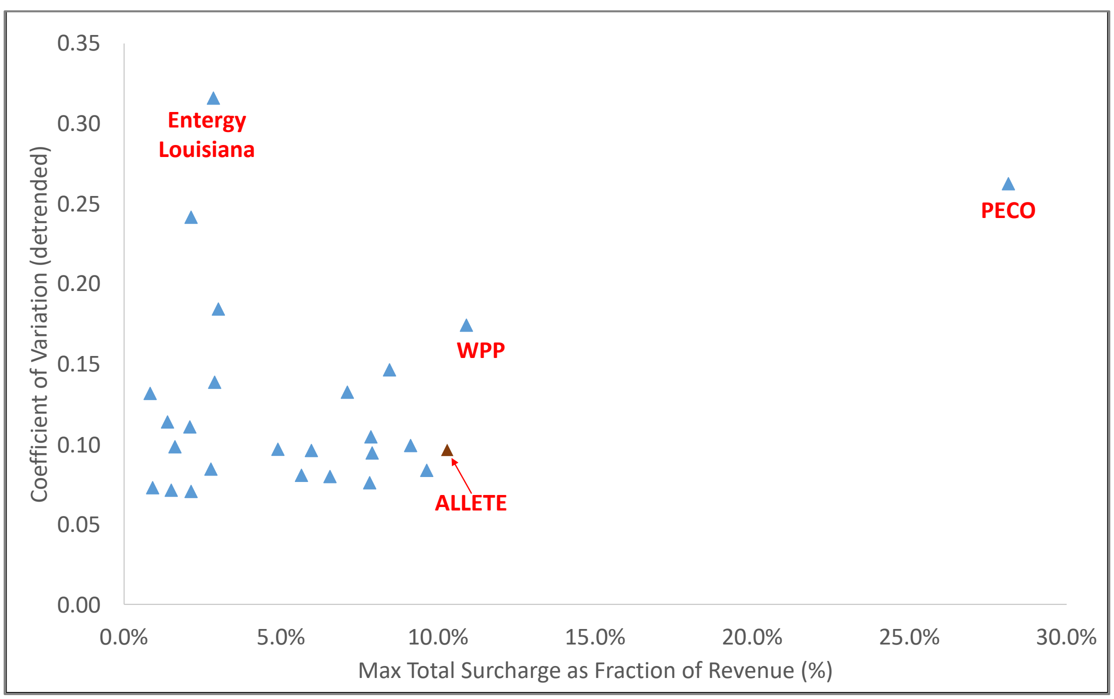
Figure 11. Revenue Volatility vs. Residential Percentage



Note: CenterPoint Energy is excluded because its volatility is the highest but not relevant.

Finally, we put the scale of a potential Minnesota Power securitization in the context of historical securitization transactions by other utilities. Figure 12 shows that the securitization of Minnesota Power's coal plant balances and expected decommissioning costs net of salvage as quantified above would likely result in a ratio of total surcharge to total utility revenues consistent with most other securitization transactions executed to date.

Figure 12. Volatility vs. Maximum Total Surcharge as Fraction of Revenue



Note: CenterPoint Energy is excluded because its volatility is the highest but not relevant.

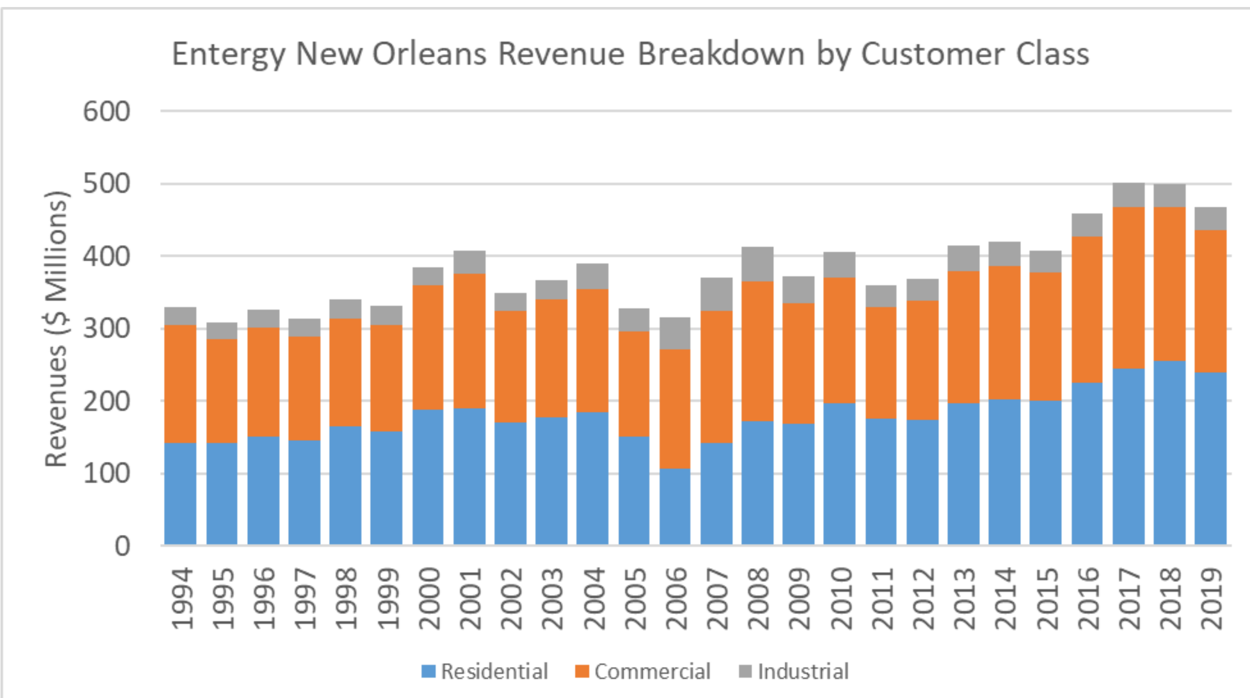
So, while Minnesota Power does have lower total revenues as well as a significantly lower fraction of those revenues coming from residential sales relative to other utilities that have successfully executed securitization transactions, these characteristics may not translate into binding constraints on size of securitization or troubling levels of revenue volatility levels relative to historical transactions.

Based on firm characteristics and conversations with credit analysts, the RMI team identified three utilities that have used securitization for case study treatment. Two of these are close "peers" of Minnesota Power, in particular in terms of revenue level.

Case Study 1: Entergy New Orleans

Like Minnesota Power, Entergy New Orleans is a small utility, with total revenues of $467 million in 2019 (see Figure 7) and also has similar volatility (in terms of the Coefficient of Volatility of the de-trended revenue, in Figure 9), with the volatility mainly driven by its storm-prone location. As shown in Figure 13, Entergy New Orleans's total revenues evidence volatility comparable in total magnitude with the volatility of Minnesota Power's historical revenues (as shown in Figure 4), driven by a combination of residential and C&I revenue fluctuations due to major storms and economic downturns.

Figure 13. Total Revenue for Entergy New Orleans 1994-2019

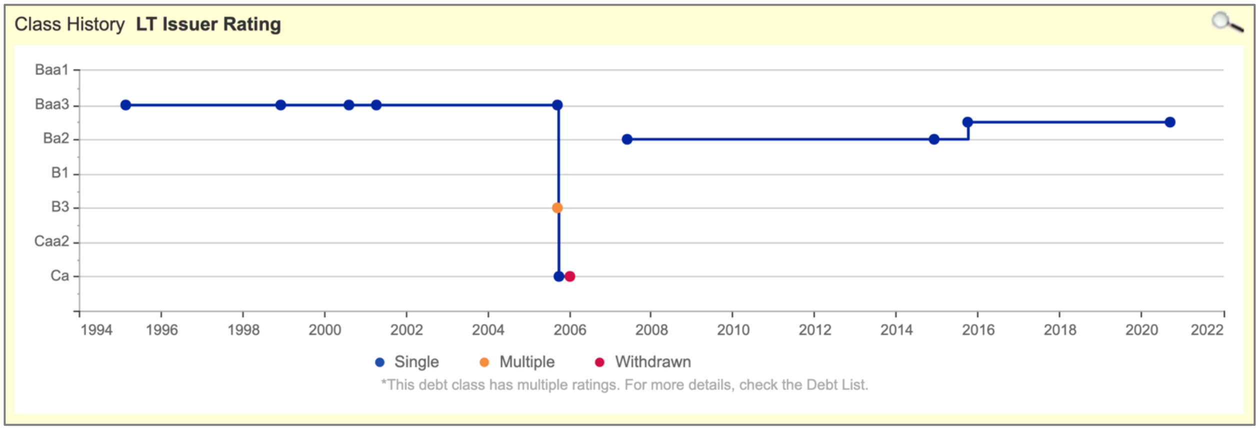


Data Source: FERC Form 1 2019.

Even though storm risk is considered "temporary," since customers are expected to eventually return to the utility's service territory, credit analysts still consider it as a critical factor for bond rating. Revenue volatility ended up becoming a major concern when credit analysts evaluated the $99 million storm recovery bond issued by Entergy New Orleans in 2015, and that bond was the first and only utility securitization transaction that didn't get AAA ratings from all three credit agencies (Aa1 from Moody's).

However, the adverse securitization rating didn't have a material impact on the company's credit rating, and the parent company, Entergy, didn't experience significant changes in risk perception by the equity market (shown in Figure 14). This was partly thanks to the relatively small size of the bond (just below $100 million). With a 9-year tenor and roughly 2.67% interest rate, the annual payment is estimated at $12.5 million in the first year (2016), which accounted for less than 3% of the total revenue collected in that year.

Figure 14. Historical Credit Ratings for Entergy New Orleans

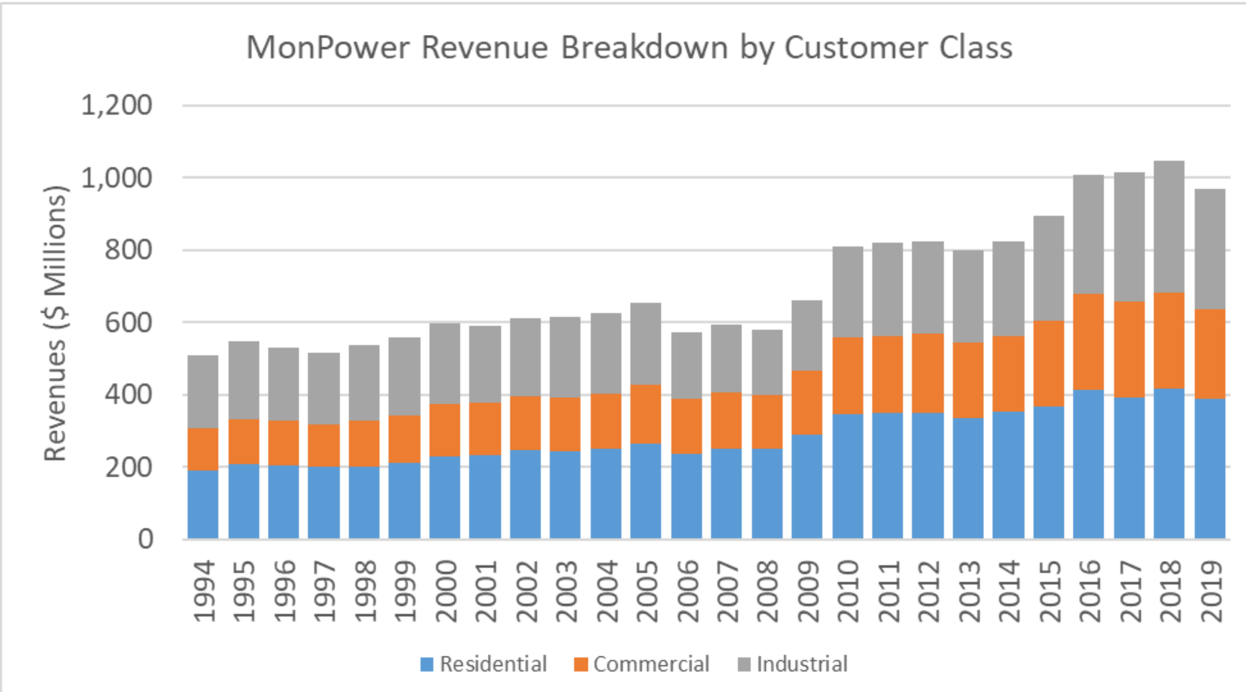


Notes: Data pulled from Moody's website. Moody's withdrew the rating for Entergy New Orleans when the company filed for bankruptcy due to costs associated with Hurricane Katrina in 2005 and resumed its rating in 2007.

<u>Case Study 2: Monongahela Power Company (MonPower)</u>

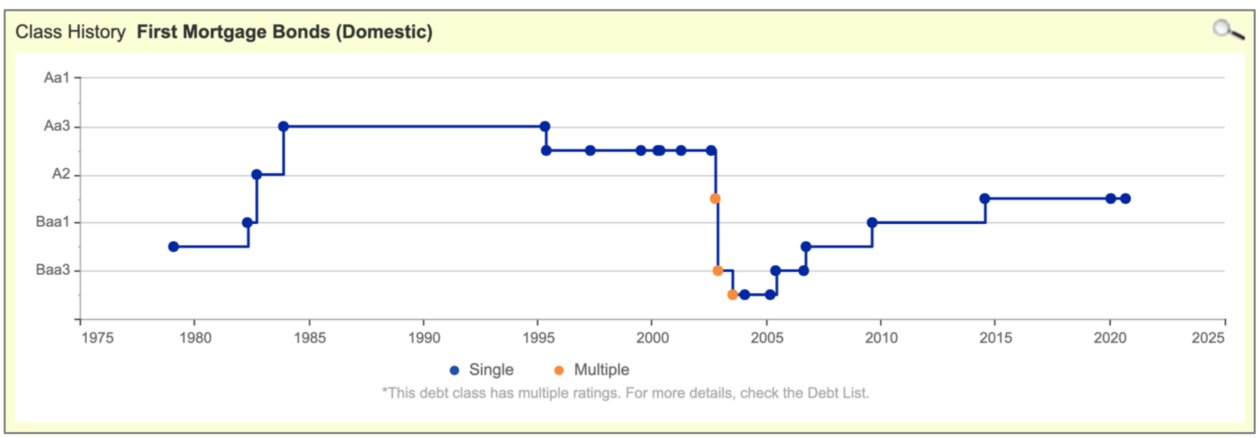
MonPower is also a relatively small utility, with $969 million in total revenues in 2019 (see Figure 7). The fraction of its revenues from residential customers (40%) is among the lowest of the 42 utilities that have issued securitization bonds (see Figure 8), although it is still significantly higher than Minnesota Power's (17%). MonPower's revenue remained stable from 1994 to 2009 and then increased over the last decade (shown in Figure 15). MonPower's two securitization bonds, issued in 2007 ($344 million) and 2009 ($64 million), were for environmental control cost recovery; total annual payments for the two bonds were estimated to have peaked at $36 million, or 5% of the total utility revenues.[xxiii] With steady growth in revenue after 2010 (but for slight declines in 2013 and 2019), MonPower's issuer rating was upgraded in 2009 and 2014 (see Figure 16).

Figure 15. Total Revenue for MonPower 1994-2019



Data Source: FERC Form 1 2019.

Figure 16. Historical Credit Ratings for MonPower



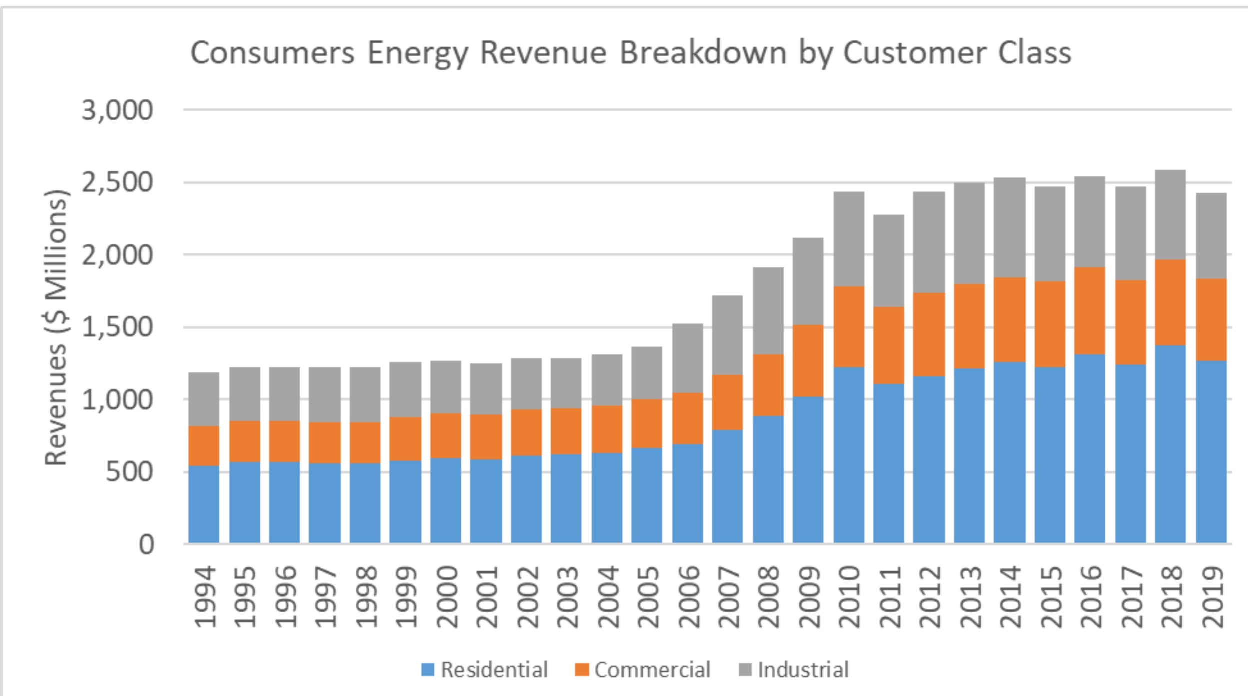
Data Source: Moody's website.

<u>Case Study 3: Consumers Energy</u>

Consumers Energy is much larger than Minnesota Power ($4.2 billion in 2019 – see Figure 7), has a higher proportion of residential customers (47% – see Figure 8), and has had relatively stable revenues (shown in Figure 17). Consumers is the only utility thus far that has fully executed a securitization transaction to recover investment costs associated with the accelerated retirement of fossil generating assets.

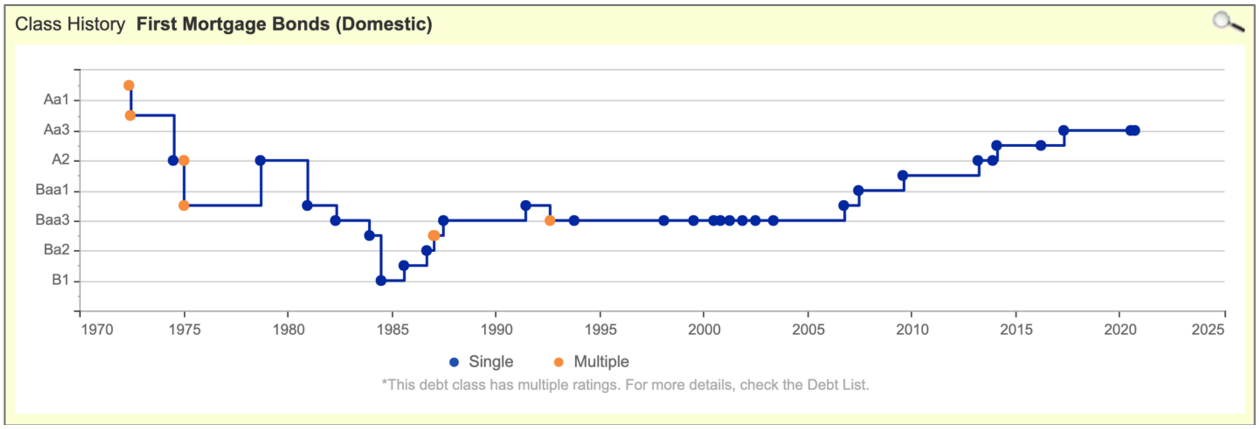
Consumers first used securitization in 2001 as part of Michigan's (partial) restructuring of its electricity industry, issuing $469 million in bonds for stranded cost recovery on the basis of the 2000 PA 142 legislation passed the previous year. In 2014, the Michigan Public Service Commission approved securitization under Act 142 to finance the recovery of the remaining book value of seven small coal plant units (and three smaller gas units) that were retired prior to the end of their depreciable lives. The second set of bonds totaling $378 million was issued in three tranches. The maximum annual payment from both sets of the bonds accounted for roughly 2% of the total revenue collected. Consumers has seen steady upgrades of credit ratings since the issuance of the first bonds (shown in Figure 18). In addition, Consumers has recently filed an application for a financing order to recover $703 million in costs associated with the accelerated retirement of two units of its Karn coal plant.

Figure 17. Total Revenue for Consumers Energy 1994-2019



Data Source: FERC Form 1 2019.

Figure 18. Historical Credit Ratings for Consumers Energy



Data Source: Moody's website.

Chapter 4. Preliminary Feasibility Assessment for Minnesota Power

There are multiple regulatory/financial approaches besides securitization that can be used to deal with unrecovered plant balances (see Table 1 for an overview). In this chapter, we focus on securitization as the chosen approach and provide an initial qualitative assessment of the steps Minnesota Power could use to mitigate potential risks and challenges. A more detailed quantitative modeling analysis will follow in Phase 2.

Minnesota Power has several options to mitigate credit risks and maximize the value of securitization for its customers

As discussed in Chapter 3, securitization transactions have been executed by utilities with historical revenue volatility similar to or greater than what Minnesota Power has experienced. Minnesota Power's risks from a securitization transaction stem mainly from the high concentration of C&I customers and, in turn, the potential impact from true-up mechanisms and other credit enhancement mechanisms if one or more large C&I customers significantly reduce consumption or even shut down operations. The use of a securitization true-up mechanism in such a case can lead to surcharges becoming noticeably large as a fraction of customer bills, resulting in political and regulatory risks. Based on conversations with credit analysts and our review of historical securitization transaction trends, we believe that the following actions can help mitigate these risks:

1) Structure securitization terms and sizes carefully

Longer securitization terms are favorable for ratepayers and utilities, because they reduce the annual and NPV impacts on customer bills while also reducing the size of the surcharge relative to total revenue. On the other hand, tenors longer than the remaining accounting life of a retired asset raise intergenerational equity concerns, as they may result in some customers paying the costs of assets from which they never would have received service. Further, as discussed in Chapter 3, these equity-related risks and concerns may be exacerbated by the fact that Minnesota Power collects a significant portion of its revenues from a handful of large industrial customers. Intergenerational equity is a complex topic, but for our purposes, two points are worth stressing:

1. To the extent that a longer term makes a securitization solution acceptable to stakeholders, it may potentially unlock savings for future customers that might not materialize at all in the absence of securitization; and

2. To the extent that securitization facilitates a more rapid transition to environmentally sustainable resources, while also providing economic benefits to today's electric power customers (and, potentially, transition assistance to affected coal plant communities), it may help avoid lasting negative climate change impacts and promote ongoing economic activity that will compound over time, to the benefit of future generations.

Careful structuring of bond tranches with different tenors and terms can help address intergeneration equity concerns while exploiting the shape of the bond yield curve to maximize savings. These structuring issues will be discussed in more detail in our Phase 2 report.

2) Implement regulatory and/or contractual measures to reduce revenue volatility

If the total securitized amount for the Boswell units were large enough that true-up impacts from C&I revenue losses would significantly affect residential ratepayer affordability, Minnesota Power could explore the following alternative revenue stabilizing measures:

Option 1: Apply additional constraints on large customers

Industrial customers have provided more than 60% of the utility's revenues in the last five years, and the largest industry – taconite and iron mining – has been the major driver for revenue volatility.

As noted, the take-or-pay contracts with these large industrial customers have provided Minnesota Power some buffer time to respond to COVID-19 impacts, but in the mid to long term, there is still a need to ensure the revenue stability through additional revenue protection mechanisms.

It would be hard to justify a simple revenue floor with these customers, especially during a pandemic when many industrial (and commercial) customers are struggling financially. Alternative measures, such as limits on true-up adjustment ratios across different customer classes, could help mitigate cost shifts to residential customers.

Option 2: Alternative design of the securitization surcharge rates

As discussed in Chapter 3, the fixed vs. demand vs. volumetric breakdown of a rate structure is likely to affect revenue volatility, particularly during economic crises when businesses such as restaurants and factories switch from full to partial operations. Fixed or demand surcharges could improve the recoverability of securitization payments. Interviews with credit analysts suggested that fixed/demand-based surcharges would lower rating agency perception of risk relative to strictly usage-based surcharges, even though customer migration and default risks would still remain.

RMI recommends exploring different surcharge rate design mechanisms and evaluating the impact on revenue volatility under different scenarios. For example, the securitization surcharge could be split across different customer classes based on the current allocation of total revenue collected, which would allow for consistency with cost-causation principles based on current obligations. Alternatively, the allocation factor could be based on the percentage of ratepayer cost savings by customer class resulting from retiring plants and securitizing the remaining plant balances. However, mechanisms that restrict flexibility to shift the burden based on future usage could increase default/defection risk among the adversely impacted customer class(es).

To demonstrate more concretely how these factors may play out, we lay out a range of potential scenarios based on the current allocation of unrecovered capital costs and the method of allocation of securitization costs. Table 3 below provides an overview of a range of scenarios considered. In theory, the capital costs associated with a generating facility built to meet both energy and capacity needs – and therefore any associated refinancing cost/savings – should be recovered purely through demand charges. In practice, each utility makes its own decision about functional allocation, typically blending capital costs into fixed and/or non-volumetric charges as well as energy rates. In Phase 2, we will dive more deeply into the functional allocation used for actual unrecovered capital costs.

- Scenario 1 is the blended approach, assuming that coal capital costs prior to securitization, as well as refinancing cost/savings, are allocated in the same fashion as other general costs, with customer class shares based on the percentage of total revenue collected from residential, commercial and industrial customers. Scenario 1 has two variations: 1-1, with the securitization costs recovered through volumetric (kWh) rates; and 1-2, with the securitizations costs recovered through monthly fixed charges.
- Scenario 2 assumes that the Boswell capital costs prior to securitization are collected in the same way as Scenario 1, while the securitization charges are allocated based purely on consumption.
- Scenario 3 is the perfect cost-causation approach, assuming that the Boswell capital costs prior to securitization, as well as refinancing cost/savings, are both recovered through demand charges.

Table 3. Summary of Current Capital Cost and Securitization Surcharge Allocation Scenarios

Scenarios	Description	Assumptions
Scenario 1: Blended Approach	1-1. Volumetric Rates: Allocation as any other general cost and can be implemented as **volumetric charges**.	Assume the recovery of costs through the combination of **revenue shares** and **energy consumption** in each class; classes providing more revenue benefit more from securitization.
	1-2. Fixed Rates: Allocation as any other general cost and can be implemented as **fixed charges**.	Assume the recovery of costs through the combination of **revenue shares** and **customer numbers** in each class; classes providing more revenues benefit more from securitization.
Scenario 2: Consumption-Based	Allocation of securitization cost is purely **consumption-based** and can be implemented as **volumetric charges**.	Assume the recovery of costs through **total energy consumption of all classes**.
Scenario 3: Demand-Based	Allocation based on cost causation as **demand charges**.	Assume the recovery of costs through **demand charge shares** and that capital costs are peak demand related.

Table 4 below summarizes the rate impacts and potential savings from different scenarios, with savings in terms of percentage or monetary reduction for each customer class, as applicable. We can see that if the capital cost and securitization cost are allocated under the same principle

(Scenario 1-1 and Scenario 1-2), the relative rate impacts on all customers should be equal. However, if the capital costs are allocated based on a blended approach while the securitization surcharge is purely based on kWh consumption and set at the same level across all customer classes (Scenario 2), residential and commercial customers will see larger relative savings compared to industrial customers. As Minnesota Power's industrial customers pay the largest share of revenue, this class would see the largest share of savings from securitization unless rate design departs significantly from this revenue pattern or the underlying revenue pattern changes markedly.

In order to make sure the benefits are allocated to balance fairness and risk mitigation, utilities may need to change functional rate design and allocation across different customer classes to mitigate significant changes to the distribution of rate impacts across customer classes from the use of securitization. The results in Table 4 suggest that collecting securitization surcharges through common volumetric rates across customer classes without further changes to rate structure would result in redistribution of costs across customer classes.

Note that this is a simplified analysis and that a more detailed analysis of rate impacts will need to consider additional variables. For example, the benefits of securitization are strongly dependent on bond structuring – the sizes and tenors of the tranches of bonds actually issued in a given securitization transaction. Historically, the majority of securitization bonds had tenors of less than 10 years, as they were used for recovery costs associated with one-off fuel or storm recovery burdens. However, we've seen longer tenors become more common as the use of the bonds has shifted to cost recovery of retired generation assets, with 15 year or longer tenors now seen as reasonable.

Option 3: Ratemaking and business model reform – changes in revenue recovery mechanisms

Business model reforms can help mitigate the financial risks of utility transition. Although none of the three credit rating agencies specifies any revenue recovery mechanisms as preferred, several credit analysts did stress during interviews that they would look into "whether revenue decoupling is in place" as a critical risk mitigation factor.

As Minnesota is investigating potential options for performance-based regulation (PBR),[xxiv] there are mechanisms (e.g., formula rates, multi-year rate plans[xxv], as well as other PBR mechanisms) that could potentially help address revenue volatility. Interviews with credit analysts suggest that no particular regulatory mechanisms are more and less favored; the critical factor is whether mechanisms can be implemented efficiently so as to enable utilities to collect robust and predictable revenue streams.[xxvi]

So far, Minnesota Power has not been granted approval for revenue stability measures and PBR measures. In the 2016 rate case, the Automatic Rate Recovery Mechanism (ARRM) was proposed but was denied following opposition from diverse stakeholders. Nevertheless, we recommend continued conversations with key stakeholders to investigate alternative mechanisms that could aid securitization, realizing that these types of initiatives can be a time-intensive process and the timing would need to be factored into a securitization effort. Revenue stability measures might seem to favor utilities over customers, but, combined with proper securitization design, they can introduce new opportunities for a "win-win."

Table 4. Rate Impact Result Summary

Scenarios	Customer Class	Capital Cost % Allocation	Securitization Surcharge % Allocation	Rate Unit	Capital Cost Rate Impact	Securitization Surcharge Rate Impact	2019 Average Rates	Savings as % reduction Capital Cost Rate Impact	Savings as % of the 2019 Average Rates
Scenario 1-1 (Blended Volumetric)	Residential	17%	17%	$/kWh	2.27	1.09	8.76	52%	14%
	Commercial	18%	18%	$/kWh	2.07	0.99	4.42	52%	25%
	Industrial	65%	65%	$/kWh	1.34	0.64	3.20	52%	22%
Scenario 1-2 (Blended Fixed)	Residential	17%	17%	$/month	16.06	7.67	92	52%	9%
	Commercial	18%	18%	$/month	90	43	133	52%	35%
	Industrial	65%	65%	$/month	19,747	9,430	79,622	52%	13%
Scenario 2 (Consumption Based)	Residential	12%	12%	$/kWh	2.27	0.74	8.76	68%	18%
	Commercial	13%	13%	$/kWh	2.07	0.74	4.42	64%	30%
	Industrial	75%	75%	$/kWh	1.34	0.74	3.20	45%	19%
Scenario 3 (Demand Based)	Residential	0%	0%	$/kW				0%	
	Commercial	7%	7%	$/kW				52%	
	Industrial	93%	93%	$/kW				52%	

Notes:

1. The 2019 average rates are calculated based on the total revenue collected by function (fixed, demand, energy) divided by the total kWh consumption or total number of customers within each customer class. Monthly peak demand information is not available; therefore, the demand charges rates are not calculated.

3) Execute securitization simultaneously with a broader transition package to focus financial analysts on transition net benefits rather than securitization in isolation

Securitization is a refinancing tool to help enable a smooth transition for utilities – and its full financial and ratepayer value is most apparent in that broader context. Executing securitization in tandem with transactions that involve deployment of additional capital or generation of replacement earnings would allow credit rating analysts and investors evaluating securitization to take into consideration the full impact of the transition, which can often be accretive to earnings and credit positive in the aggregate.

The cost savings from securitization primarily come from removal of an older plant from rate base and replacing it with securitization bonds at lower financing cost (with the bond designed to achieve the most favorable credit ratings). The savings from securitization can be used to support community transition and mitigate the local economic impacts from closing coal plants; transition assistance is often left out of the risk-and-reward evaluation of a securitization, but it can be a critical component of a successful transition.

Several key criteria need to be met to ensure a successful execution of securitization

Relative to the utilities that have historically used securitization, Minnesota Power's revenues are smaller and come from a more highly concentrated base of large industrial customers. Here, we summarize some key criteria based on the analysis of securitization benefits, risks, and challenges above.

In order to determine the feasibility of issuing securitization to achieve "win-win-win" for utilities, ratepayers and communities in the transition, Minnesota Power should make sure the following key criteria are met in any implementation plan:

Key Criterion 1: The overall ratepayer cost reduction from securitization should outweigh the transaction costs. These transaction costs include bond underwriting fees, as well as legal and regulatory oversight expenses related to the financing order and bond issuance.

Key Criterion 2: The bond issuance should be structured to balance cost reductions and risks (e.g., to ratepayer classes, existing shareholder, and bondholders). This requires a careful design of the bond tenor and tranches in conjunction with downside scenario analysis.

Key Criterion 3: The bond should not cause significant cross-subsidization; intergenerational impacts, both direct and indirect, should be explicitly addressed and, to the extent possible, quantitatively modeled. This requires a careful design of the securitization surcharge, so it is in line with cost-causation principles. The true-up mechanism should account for scenarios where large customers shut down for an extended period in the future.

Key Criterion 4: Legislative and regulatory processes needed to allow the use of securitization and to achieve a AAA rating should be executed in a coordinated and timely fashion. Figure 19 is a simplified schematic of the required steps from the beginning of the conversation among stakeholders though the identification of use cases for securitization and concluding with bond issuance to the market. However, political processes are not easy to predict nor are they necessarily timely. The lack of control over the timing and content in development of securitization legislation must be recognized as a gating factor.

Figure 19. Securitization Action Map: Who needs to be involved and when

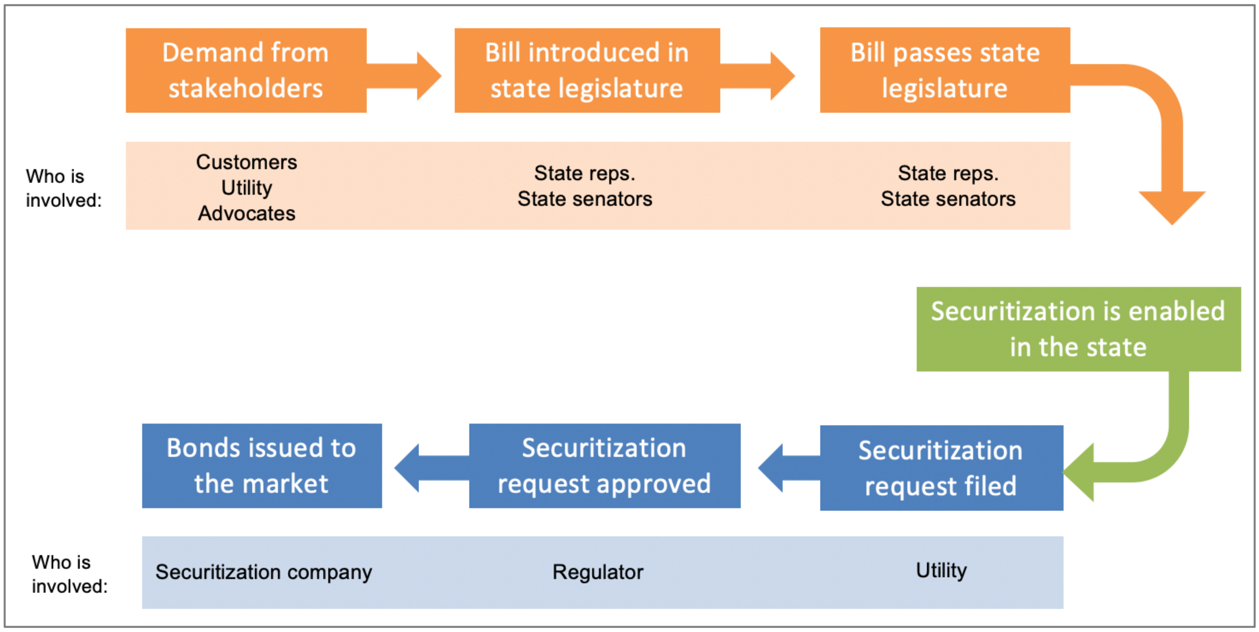
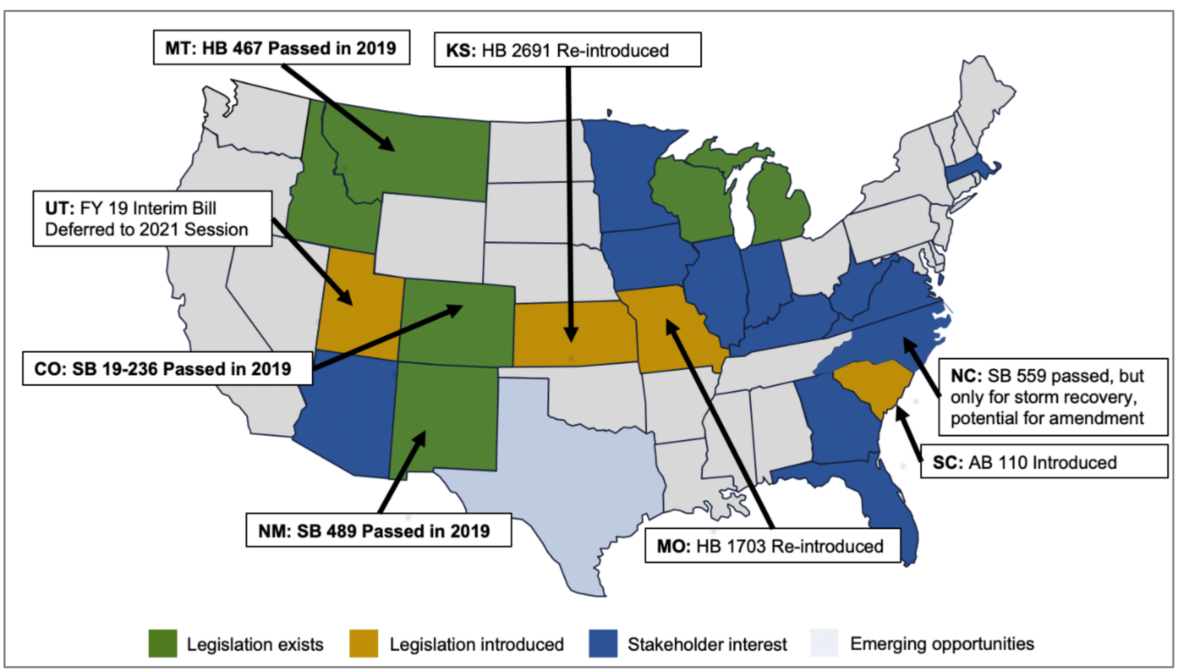


Figure 20 below is a map that indicates where bills to use securitization for recovery of costs associated with accelerated plant retirement have been passed or are under consideration for the 2021 legislative session. Many of the securitization bonds issued during wholesale market restructuring in the 1990s were issued under laws that are no longer active. Arizona is considering securitization transactions in the absence of legislation, but this reflects the unusual constitutional role that the Arizona Corporation Commission plays alongside the legislative, executive, and judiciary branches of government. Appendix C includes excerpts/examples from securitization bills recently passed.

Figure 20. Securitization Legislation Progress Map



Key Criterion 5: All stakeholders should be clearly aligned on the costs to be borne, benefits to be received, and roles expected from each other. As laid out in Figure 19, different stakeholders are expected to take a leading role at different stages.

In states where there are securitization bills in place for purposes other than plant retirement cost recovery (e.g. pollution control equipment, storm cost recovery), additional language to expand use of proceeds should include:

> "the unrecovered capitalized cost of a retired electric generating facility,"
>
> "cost of decommissioning, if costs are more than the utility has previously collected from ratepayers," and
>
> "transition assistance for communities and workers directly affected by generating station closures."

In states where there is no precedent for utility securitization, legislators will need to start from scratch and make sure the bill includes the key components to meet rating agency criteria as well as ratepayer, utility, and community needs.

Once the state legislature passes a securitization bill, utilities can file a request for a financing order from the public utility commission for permission to issue the bonds. Regulators should conduct a comprehensive assessment of utility's proposed plan to ensure that the bonds meet all the standard requirements specified in the securitization legislation. Furthermore, utility customers and consumer advocates can help initiate and socialize securitization conversations. For Minnesota Power, a critical component of successful implementation of securitization will be the support of customers, including the Large Power customers.

Given the challenges that Minnesota Power is facing, it is advisable to continue communications with stakeholders – including regulators, financial investors and advocates – to ensure that the cost and benefits of securitization are clearly understood across the board.

Chapter 5. Additional Research and Analysis Needed for Phase 2

After submitting this report, the RMI team will enter Phase 2 of the project, which will focus on quantitative analysis of the impact of securitization. The final deliverable at the end of Phase 2 will be a Securitization Plan to be submitted by Minnesota Power to the Commission by February 1, 2021. The final report will cover discussion of the following topics.

Financial and revenue requirement impact analysis of securitization for Minnesota Power

In Phase 2, Minnesota Power and the RMI team are planning to conduct a comprehensive financial analysis to evaluate the costs and benefits of accelerated generation asset retirement with securitization compared with:

- continued operation of the plants,
- accelerated depreciation prior to retirement, and/or
- creation of a regulatory asset with capital recovery after retirement.

For each of these cases, the analysis will consider:

- a set of retirement schedules and utility earnings recovery mechanisms through either rate-based replacement assets or alternative business models; and
- the impacts on various relevant stakeholders, including utility earnings impacts, ratepayer near- and long-term cost impacts, economic/financial impacts on the coal plant employees and surrounding communities, as well as the financial and credit rating impacts on ALLETE as a whole.

This analysis will be conducted in parallel with Minnesota Power's two concurrent planning studies – the baseload retirement study and the IRP.

Securitization risk assessment

We will evaluate the feasibility of achieving a AAA rating for the analyzed securitization scenarios by simulating the metrics and stress tests used by three credit rating agencies. The feasibility assessment will include "stress cases" to test for potential revenue shortfalls. It should also examine new rate mechanisms that can contribute to revenue stabilization in economic downturns, as well as the regulatory feasibility and actions needed to enable those mechanisms.

Next steps

The RMI team will work with Minnesota Power to share the results of the Phase 1 report with stakeholders and to gather feedback on the report as we move toward conducting the Phase 2 analyses.

Minnesota Power will assess the Phase 2 analysis and incorporate insights in its Integrated Resource Plan as to whether and how securitization may be used to mitigate potential ratepayer impacts associated with any early retirement of one or both of the Boswell 3 and 4 facilities.

Appendix A. Securitization Transaction Summary [xxvii]

Appendix A. Table 1. Securitization related to stranded costs (37 issuances)

Date (M/Y)	Utility	Issuer	Ratings at Issuance	Size ($mm)	Use of Proceeds
Jun-95	Baltimore Gas & Electric Co.			623	Stranded Costs
Nov-97	Pacific Gas and Electric Co.	California Infrastructure and Economic Development Bank Special Purpose Trust PG&E-1	Aaa/AAA/AAA	2,901	Stranded Costs
Dec-97	Southern California Edison Co.	California Infrastructure and Economic Development Bank Special Purpose Trust SCE-1	Aaa/AAA/AAA	2,463	Stranded Costs
Dec-97	San Diego Gas & Electric Co.	California Infrastructure and Economic Development Bank Special Purpose Trust SDG&E,-1	Aaa/AAA/AAA	658	Stranded Costs
Dec-98	NorthWestern Corp. — Gas	MPC Natural Gas Funding Trust 1998-1	Aaa/AAA/AAA	63	Stranded Costs
Dec-98	Commonwealth Edison Co.	ComEd Transitional Funding Trust	Aaa/AAA/AAA	3,400	Stranded Costs
Dec-98	Ameren Illinois Co.	Illinois Power Special Purpose Trust	Aaa/AAA/AAA	864	Stranded Costs
Mar-99	PECO Energy Co.	PECO Energy Transition Trust	Aaa/AAA/AAA	4,000	Stranded Costs
Jul-99	NSTAR Electric Co.	Massachusetts RRB Special Purpose Trust BEC-1	Aaa/AAA/AAA	725	Stranded Costs
Jul-99	PPL Electric Utilities Inc.	PP&L Transition Bond Company LLC	Aaa/AAA/AAA	2,420	Stranded Costs
Nov-99	West Penn Power Co.	West Penn Funding, LLC	Aaa/AAA/AAA	600	Stranded Costs
Apr-00	PECO Energy Co.	PECO Energy Transition Trust	Aaa/AAA/AAA	1,000	Stranded Costs
Jan-01	Public Service Electric & Gas Co.	PSE&G Transition Funding LLC	Aaa/AAA/AAA	2,525	Stranded Costs
Mar-01	DTE Electric Co.	The Detroit Edison Securitization Funding LLC	Aaa/AAA/AAA	1,750	Stranded Costs
Mar-01	Connecticut Light & Power Co.	Connecticut RRB Special Purpose Trust CL&P-1	Aaa/AAA/AAA	1,438	Stranded Costs
Apr-01	Public Service Co. of New Hampshire	PSNH Funding LLC	Aaa/AAA/AAA	525	Stranded Costs
May-01	NSTAR Electric Co.	Massachusetts RRB Special Purpose Trust WMECO-1	Aaa/AAA/AAA	155	Stranded Costs
Oct-01	CenterPoint Energy Houston Electric LLC	CenterPoint Energy Transition Bond Company I, LLC	Aaa/AAA/AAA	749	Stranded Costs
Oct-01	Consumers Energy Co.	Consumers Funding LLC	Aaa/AAA/AAA	469	Stranded Costs
Jan-02	Public Service Co. of New Hampshire	PSNH Funding LLC 2	Aaa/AAA/AAA	50	Stranded Costs
Jan-02	AEP Texas Inc.	CPL Transition Funding LLC	Aaa/AAA/AAA	797	Stranded Costs
Jun-02	Jersey Central Power & Light Co.	JCP&L Transition Funding LLC	Aaa/AAA/AAA	320	Stranded Costs
Dec-02	Atlantic City Electric Co.	Atlantic City Electric Transition Funding LLC	Aaa/AAA/AAA	440	Stranded Costs
Aug-03	Oncor Electric Delivery Co.	Oncor Electric Delivery Transition Bond Company LLC	Aaa/AAA/AAA	500	Stranded Costs
Dec-03	Atlantic City Electric Co.	Atlantic City Electric Transition Funding LLC	Aaa/AAA/AAA	152	Stranded Costs
May-04	Oncor Electric Delivery Co.	TXU Electric Delivery Transition Bond Company LLC	Aaa/AAA/AAA	790	Stranded Costs
Jul-04	Rockland Electric Co.	Rockland Electric Company Transition Funding LLC	Aaa/AAA/AAA	46	Stranded Costs
Jan-05	Pacific Gas and Electric Co.	PG&E Energy Recovery Funding LLC	Aaa/AAA/AAA	1,888	Stranded Costs
Feb-05	NSTAR Electric Co.	Massachusetts RRB Special Purpose Trust 2005-1	Aaa/AAA	675	Stranded Costs
Sep-05	West Penn Power Co.	West Penn Power, Ser. 2005-A	Aaa/AAA/AAA	115	Stranded Costs
Dec-05	CenterPoint Energy Houston Electric LLC	CenterPoint Energy Transition Bond Company II, LLC	Aaa/AAA/AAA	1,851	Stranded Costs
Oct-06	AEP Texas Inc.	AEP Texas Central Transition Funding II LLC	Aaa/AAA/AAA	1,740	Stranded Costs
Jan-08	CenterPoint Energy Houston Electric LLC	CenterPoint Energy Transition Bond III, LLC	Aaa/AAA/AAA	488	Stranded Costs
Sep-11	Entergy Louisiana LLC	Entergy Louisiana Investment Recovery Funding I, LLC	Aaa(sf)/AAA(sf)/AAA(sf)	207	Stranded Costs
Jan-12	CenterPoint Energy Houston Electric LLC	CenterPoint Energy Transition Bond Company IV, LLC	Aaa(sf)/AAA(sf)/AAA(sf)	1,695	Stranded Costs
Mar-12	AEP Texas Inc.	AEP Texas Central Transition Funding III LLC	Aaa(sf)/AAA(sf)/AAA(sf)	800	Stranded Costs
May-18	Public Service Co. of New Hampshire	PSNH Funding LLC 3	Aaa(sf)/AAA(sf)/AAA(sf)	636	Stranded Costs

Data Sources: Saber Partners - https://saberpartners.com/list-of-investor-owned-utility-securitization-rocrrb-bond-transactions-1997-present/, S&P Market Intelligence, RMI Analysis.

Appendix A. Table 2. Securitization related to storm recovery (15 issuances)

Date (M/Y)	Utility	Issuer	Ratings at Issuance	Size ($mm)	Use of Proceeds
May-07	Entergy Mississippi LLC			48	Storm Recovery
May-07	Florida Power & Light Co.	FPL Recovery Funding LLC	Aaa/AAA/AAA	652	Storm Recovery
Jun-07	Mississippi Power Co.			121	Storm Recovery
Jun-07	Entergy Texas Inc.	Entergy Gulf States Reconstruction Funding I, LLC	Aaa/AAA/AAA	330	Storm Recovery
Feb-08	Cleco Power LLC	Cleco Katrina/Rita Hurricane Recovery Funding LLC	Aaa/AAA/AAA	181	Storm Recovery
Jul-08	Entergy Louisiana LLC	Louisiana Public Facilities Authority	Aaa/AAA/AAA	688	Storm Recovery
Jul-08	Entergy Gulf States LLC	Louisiana Public Facilities Authority	Aaa/AAA/AAA	278	Storm Recovery
Oct-09	Entergy Texas Inc.	Entergy Texas Restoration Funding, LLC	Aaa/AAA/AAA	546	Storm Recovery
Jul-10	Entergy Gulf States LLC	Louisiana Local Government Environmental Facilities and Community Development Authority	Aaa/AAA/AAA	244	Storm Recovery
Jul-10	Entergy Louisiana LLC	Louisiana Local Government Environmental Facilities and Community Development Authority	Aaa/AAA/AAA	469	Storm Recovery
Aug-10	Entergy Arkansas LLC	Entergy Arkansas Energy Restoration Funding, LLC	Aaa(sf)/AAA(sf)/AAA(s	124	Storm Recovery
Aug-14	Entergy Louisiana LLC	Louisiana Local Government Environmental Facilities and Community Development Authority	Aaa(sf)/AAA(sf)/AAA(s	244	Storm Recovery
Aug-14	Entergy Gulf States LLC	Louisiana Local Governments Environmental Facilities Authority	Aaa(sf)/AAA(sf)/AAA(s	71	Storm Recovery
Jul-15	Entergy New Orleans LLC	Entergy New Orleans Storm Recovery Funding I, L.L.C.	Aa1(sf)/AAA(sf)	99	Storm Recovery
Sep-19	AEP Texas Inc.	AEP Texas Restoration Funding LLC	Aaa(sf)/AAA(sf)	235	Storm Recovery

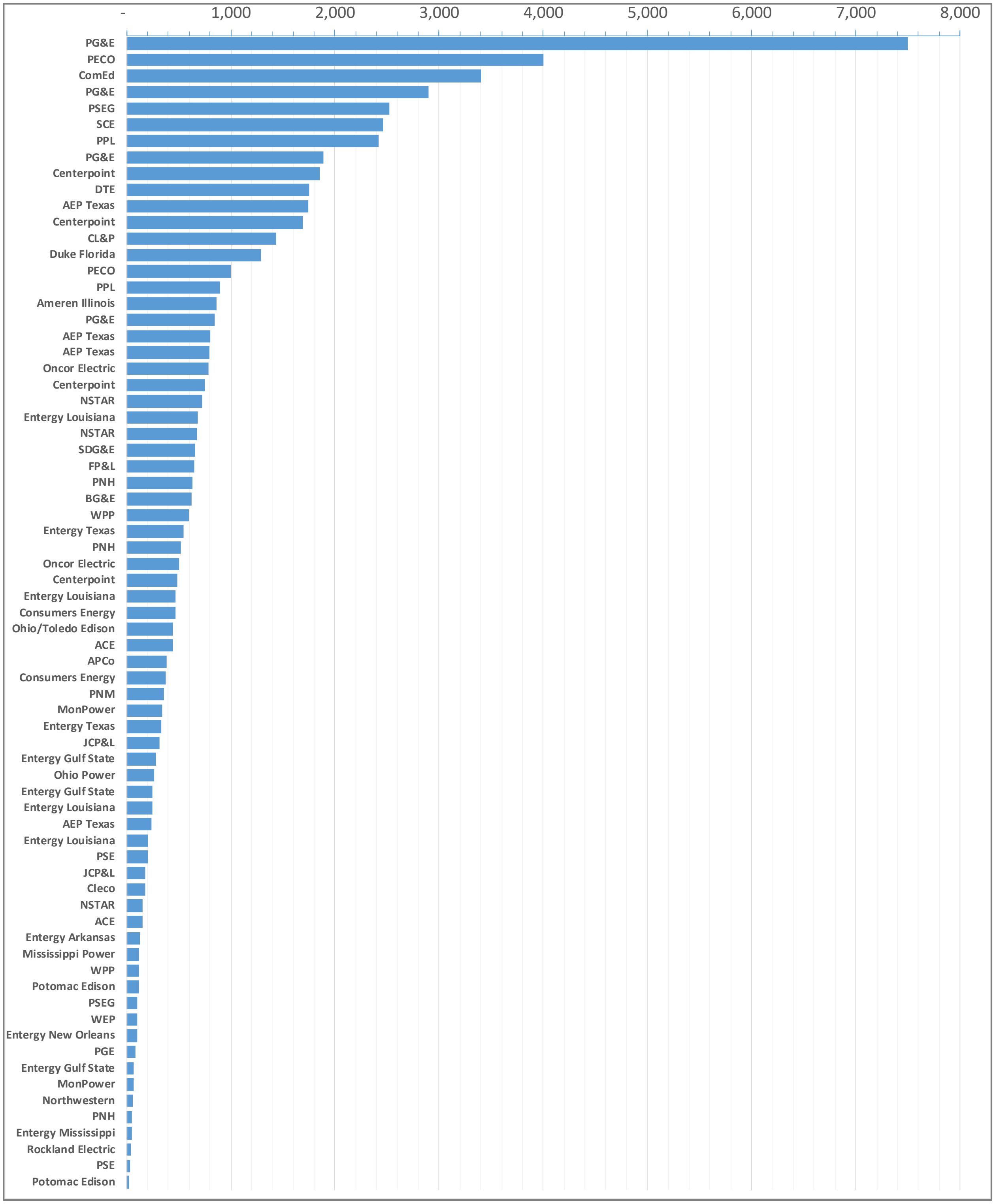
Appendix A. Table 3. Securitization related to other purposes (16 issuances, 4 pending), organized chronologically within groups of bonds with similar uses of proceeds (plant retirement highlighted)

Date (M/Y)	Utility	Issuer	Ratings at Issuance	Size ($mm)	Use of Proceeds
Jun-95	Puget Sound Energy Co.			203	Energy Conservation Programs
Oct-96	Portland General Electric Co.			81	Energy Conservation Programs
Aug-97	Puget Sound Energy Co.			35	Energy Conservation Programs
Aug-01	PPL Electric Utilities LLC			900	Transmission and Distribution
Sep-05	Public Service Electric & Gas Co.	PSE&G Transition Funding II LLC	Aaa/AAA/AAA	103	Deferred Balances
Oct-05	Pacific Gas and Electric Co.	PG&E Energy Recovery Funding LLC	Aaa/AAA/AAA	845	Regulatory Asset
Aug-06	Jersey Central Power & Light Co.	JCP&L Transition Funding II LLC	Aaa/AAA/AAA	182	Deferred Balances
Apr-07	Monongahela Power Co.	MP Environmental Funding LLC	Aaa/AAA/AAA	345	Environmental Compliance Investments
Apr-07	Potomac Edison Co.	PE Environmental Funding LLC	Aaa/AAA/AAA	115	Environmental Compliance Investments
Dec-09	Potomac Edison Co.	PE Environmental Funding LLC	Aaa/AAA/AAA	22	Environmental Compliance Investments
Dec-09	Monongahela Power Co.	MP Environmental Funding LLC	Aaa/AAA/AAA	64	Environmental Compliance Investments
Jun-13	Ohio Edison Co./Toledo Edison Co./Cleveland Electric Illuminating Co.	FirstEnergy Ohio PIRB Special Purpose Trust 2013	Aaa(sf)/AAA(sf)/AAA(s	445	Deferred Balances
Jul-13	Ohio Power Co.	Ohio Phase-In-Recovery Funding, LLC	Aaa(sf)/AAA(sf)/AAA(s	267	Deferred Balances
Nov-13	Appalachian Power Co.	Appalachian Consumer Rate Relief Funding LLC	Aaa(sf)/AAA(sf)/AAA(s	380	Deferred Balances
Jul-14	Consumers Energy Co.	Consumers 2014 Securitization Funding, LLC	Aaa(sf)/AAA(sf)/AAA(s	378	Coal Plant Retirement
Jun-16	Duke Energy Florida LLC	Duke Energy Florida Project Finance, LLC	Aaa(sf)/AAA(sf)/AAA(s	1,294	Nuclear Plant Retirement
Pending	Public Service Co. of New Mexico			361	Coal Plant Retirement
Pending	Wisconsin Electric Power Co.			118	Coal Plant Retirement
Pending	Consumers Energy Co.			703	Coal Plant Retirement
Pending	Pacific Gas & Electric Co.			7,500	Liabilities 2017 Wildfires

Data Sources: Saber Partners - https://saberpartners.com/list-of-investor-owned-utility-securitization-rocrrb-bond-transactions-1997-present/, S&P Market Intelligence, RMI Analysis. Additional Notes:

- In the cases in which bonds were co-issued by more than one utility, our financial analyses included each issuer separately: Monongahela Power Co. and Potomac Edison Co. co-issued 2007 and 2009 environmental bonds; Ohio Edison Co. and Toledo Edison Co. co-issued 2013 FirstEnergy bonds.
- Three state issuers are excluded: State of Hawaii Department of Business, Economic Development, and Tourism; District of Columbia; and State of Connecticut.
- AEP Texas was excluded from our analyses due to lack of recent financial data reported via FERC Form.

Appendix A. Figure 1. Securitization bond size overview (Bond Size, Million $, Nominal)



Appendix B. Historical Revenue Trends Summary

Utility Short Name	FERC ID	Utility Full Name in FERC	2019 Total Revenue ($)	Coefficient of Variation (Detrend)	Coefficient of Variation (Original)	2019 Residential Percentage (%)
ALLETE	98	ALLETE, Inc.	641,169,420	0.10	0.23	17%
Ameren Illinois	443	Ameren Illinois Company	1,471,397,714	0.11	0.13	58%
APCo	6	Appalachian Power Company	2,429,129,228	0.11	0.32	52%
ACE	9	Atlantic City Electric Company	1,008,909,000	0.10	0.11	65%
BG&E	10	Baltimore Gas and Electric Company	1,998,471,471	0.10	0.11	67%
Centerpoint	68	CenterPoint Energy Houston Electric, LLC	2,198,507,942	0.47	0.55	53%
Cleco	22	Cleco Power LLC	876,059,556	0.14	0.32	48%
Cleveland Electric	30	Cleveland Electric Illuminating Company, The	961,707,297	0.16	0.27	46%
ComEd	32	Commonwealth Edison Company	4,798,823,031	0.08	0.13	59%
CL&P	39	Connecticut Light and Power Company, The	2,867,863,947	0.15	0.16	64%
Consumers Energy	41	Consumers Energy Company	4,183,869,242	0.07	0.25	47%
DTE	44	DTE Electric Company	4,881,073,083	0.08	0.16	50%
Duke Florida	55	Duke Energy Florida, LLC	4,331,838,444	0.11	0.27	65%
Entergy Arkansas	8	Entergy Arkansas, Inc.	1,840,694,867	0.07	0.17	43%
Entergy Gulf State	63	Entergy Gulf States Louisiana, L.L.C.		0.32	0.32	33%
Entergy Louisiana	454	Entergy Louisiana, LLC	3,645,424,590	0.32	0.41	35%
Entergy Mississippi	100	Entergy Mississippi, Inc.	1,170,882,526	0.11	0.17	48%
Entergy New Orleans	114	Entergy New Orleans, Inc.	467,483,057	0.09	0.14	51%
Entergy Texas	315	Entergy Texas, Inc.	1,287,368,918	0.09	0.09	47%
FP&L	56	Florida Power & Light Company	10,988,034,983	0.13	0.26	61%
JCP&L	77	Jersey Central Power & Light Company	1,693,822,772	0.18	0.18	65%
Mississippi Power	99	Mississippi Power Company	864,827,320	0.08	0.28	32%
MonPower	101	MONONGAHELA POWER COMPANY	968,928,298	0.10	0.25	40%
Northwestern	122	NorthWestern Corporation	872,636,226	0.21	0.65	43%
NSTAR	309	NSTAR Electric Company	2,758,635,669	0.08	0.09	48%
Ohio Edison	126	Ohio Edison Company	1,301,484,980	0.14	0.22	60%
Ohio Power	127	Ohio Power Company	2,492,322,660	0.24	0.40	59%
Oncor Electric	282	Oncor Electric Delivery Company LLC	3,469,227,827	0.04	0.25	49%
PG&E	133	PACIFIC GAS AND ELECTRIC COMPANY	12,203,376,256	0.07	0.22	40%
PECO	135	PECO Energy Company	2,219,316,942	0.26	0.27	72%
PGE	141	Portland General Electric Company	1,778,044,307	0.06	0.24	52%
PPL	138	PPL Electric Utilities Corporation	1,832,960,674	0.21	0.23	76%
PNH	146	Public Service Company of New Hampshire	952,305,393	0.10	0.11	59%
PNM	147	Public Service Company of New Mexico	920,227,210	0.10	0.28	46%
PSEG	149	Public Service Electric and Gas Company	3,798,839,498	0.10	0.10	54%
PSE	150	Puget Sound Energy, Inc.	2,108,996,284	0.08	0.25	54%
Rockland Electric	152	Rockland Electric Company	159,058,558	0.17	0.21	64%
SDG&E	155	San Diego Gas & Electric Company	3,328,491,890	0.13	0.33	44%
SCE	161	Southern California Edison Company	10,685,561,920	0.08	0.19	42%
Potomac Edison	142	THE POTOMAC EDISON COMPANY	759,224,472	0.10	0.11	66%
Toledo Edison	175	Toledo Edison Company, The	415,882,621	0.18	0.27	55%
WPP	188	WEST PENN POWER COMPANY	971,482,534	0.17	0.17	71%
WEP	193	Wisconsin Electric Power Company	2,804,124,481	0.08	0.29	43%

Appendix C. Summary of Key Elements of Recent Securitization Legislation

Appendix C. Table 1. Colorado Energy Impact Bond Act

Key Elements	Distinctive Features
Status	SB19-236 signed on May 30,2019; Financing Order not introduced
Key Utilities in the State	Xcel Energy
Allowable Use of Proceeds	Recover, finance or refinance "pretax cost", including - "The unrecovered capitalized cost of a retired electric generating facility", - "Costs of decommissioning and restoring the site of the electric generating facility", and - "Other applicable capital and operating costs, accrued carrying charges, deferred expenses, reductions for applicable insurance and salvage proceeds and the costs of retiring any existing indebtedness, fees, costs", and - "Expenses to modify existing debt agreements or for waivers or consents related to existing debt agreements" - "Amounts for assistance to affected workers and communities if approved by the commission."
Transition Assistance	- Community assistance is to be provided in amounts equal to costs of voter-approved projects expected to be paid from revenue sources impacted by retirements
Replacement Resources	- Allows utilities to own up to 50% of replacement resources
Bond Tenor	- Long tenor bonds (up to 30 years), enabling low bond costs and attracting long term investors

Appendix C. Table 2. New Mexico Energy Transition Act

Key Elements	Distinctive Features
Status	SB489 signed on May 22, 2019; Financing Order filed on January 28, 2020 San Juan plant will be abandoned July 1, 2022
Key Utilities in the State	Public Service Company of New Mexico
Allowable Use of Proceeds	Recover, finance or refinance "energy transition cost", including financing costs and the abandonment costs that include: - "Plant decommissioning and mine reclamation costs"; - "Severance and job training for employees losing their jobs as a result of an abandoned qualifying generating facility and any associated mine that only services the abandoned qualifying generating facility"; - "Undepreciated investments as of the date of abandonment".
Transition Assistance	Allocate the bond proceeds at the following percentage: - 1.5% to the Indian affairs department for deposit in the energy transition Indian affairs fund; - 1.65% to the economic development department for deposit in the energy transition economic development assistance fund; - 3.35% to the workforce solutions department for deposit in the energy transition displaced worker assistance fund.
Replacement Resources	- Detailed process for utilities to acquire replacement resources through competitive procurement, with attention to locating them in areas impacted by plant retirement and to local jobs and economic development.

Appendix C. Table 3. Montana Energy Assistance Bond Act

Key Elements	Distinctive Features
Status	HB467 signed on May 1, 2019; Financing Order not introduced
Key Utilities in the State	Montana Dakota Utility (MDU)
Allowable Use of Proceeds	Recover, finance or refinance "Montana energy impact assistance costs", including: - "Unrecovered capitalized costs of retired or replaced electric infrastructure or facilities"; - "Costs of decommissioning and restoring the site of the electric infrastructure or facility"; - "Other applicable capital and operating costs, accrued carrying charges, deferred expenses, reductions for applicable insurance and salvage proceeds"; and - "The costs of retiring any existing indebtedness, fees, costs, and expenses to modify existing debt agreements or for waivers or consents related to existing debt agreements".
Transition Assistance	- Not included
Replacement Resources	- Utilities may build and own least cost new generation, including storage and network modernization to support least cost generation.
Bond Tenor	- Long tenor bonds (30 years), rated AA or Aa2 or better

Appendix C. Table 4. Kansas Electricity Bill Reduction Bonds Act (K-EBRA)

Key Elements	Distinctive Features
Status	HB2691 re-introduced in 2020
Key Utilities in the State	Evergy
Allowable Use of Proceeds	Recover, finance or refinance "K-EBRA costs", including "the pretax costs" that incur: - "Caused by or associated with electric utility property currently included in the rate base of an electric utility or remain as a result of the retirement of an electric generating facility located in the state"; - "In providing transition assistance to Kansas communities and electric generation facility workers that are directly impacted by the retirement of electric generation facilities"; and - "In constructing or acquiring renewable facilities and services, including least-cost electric generation facilities and other supply-side and demand-side resources; and - "Any reasonable and necessary administrative and operating costs, as required by a financing order".
Transition Assistance	- Included, no specified amount
Replacement Resources	- Included in the use of proceeds, but no specifics
Bond Tenor	- Long term bonds (up to 30 years)

Endnotes

[i] New Mexico PRC, 19-00018-UT, *In the matter of Public Service Company of New Mexico's Abandonment of San Juan Generating Station Units 1 and 4.* https://www.pnm.com/documents/396023/14794762/PNM-19-00018-UT-Abandon+SJGS-6.125x16-072919.pdf/f0bdcab2-e6ce-d5d2-1809-95a225f1e4ff?t=1564585251391

[ii] PSC of Wisconsin, Docket No. 6630-ET-101, PSC REF#:393907, *Application for Financing Order*. https://apps.psc.wi.gov/pages/viewdoc.htm?docid=393907

[iii] Michigan PSC, Case Number U-20889, *In the matter of the application of Consumers Energy Company for a Financing Order Approving the Securitization of Qualified Costs*, filed 9/18/2020. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000EhPH7AAN

[iv] Ongoing CAPEX investment means plant balances do not decline simply as a function of plant age, but reflect plant size and complexity, both of which correlated with local tax revenues and labor force size.

[v] A $99 million storm recovery bond issued by Entergy New Orleans in 2015; for more on this issuance, see Chapter 3 of this report.

[vi] Fitch Ratings, *U.S. Utility Tariff/Stranded Cost Bonds Rating Criteria*, December 10, 2019, https://www.fitchratings.com/research/structured-finance/us-utility-tariff-stranded-cost-bonds-rating-criteria-10-12-2019

[vii] Ibid.

[viii] Ibid.

[ix] Ibid.

[x] Ibid.

[xi] Moody's, *Utility Cost Recovery Charge Securitizations Methodology*, June 3, 2020.

[xii] Information collected from expert interviews.
[xiii] Data collected from EIA 860 2019ER.
[xiv] "Coal-fired operations to end at Taconite Harbor Energy Center; plant will be idled in 2016," July 9, 2015, accessed on July 18, 2010 at https://www.duluthnewstribune.com/news/3782973-coal-fired-operations-end-taconite-harbor-energy-center-plant-will-be-idled-2016
[xv] Data collected from EIA 823 2019ER.
[xvi] Direct Testimony from Frank L. Frederickson before the MN PUC, "Large Power Customer Outlook," In the Matter of the Application of Minnesota Power For Authority to Increase Rates for Electric Utility Service in Minnesota, Docket No. E015/GR-19-442, November 1, 2019.
[xvii] "Extended unemployment for miners on the table at Minnesota Legislature," July 2020, accessed on July 18, 2020 at http://www.businessnorth.com/daily_briefing/extended-unemployment-for-miners-on-the-table-at-minnesota-legislature/article_b95c0bba-c85b-11ea-94dd-cf8db056a18b.html
[xviii] CenterPoint Energy Houston Electric LLC Form 8-K submitted on 2002-09-03, accessed on September 14, 2020 at https://sec.report/Document/0000950129-02-004444/
[xix] "PECO Electric Rates Drop Almost 30% Since 2011 Helping Customers to Continue to Save Big on Energy Costs," March 2017, accessed on September 2, 2020 at https://www.peco.com/News/Pages/Press%20Releases/PECO-Electric-Rates-Drop-Almost-30-Since-2011.aspx
[xx] Company 10-K, accessed on September 2, 2010 at https://www.sec.gov/Archives/edgar/data/20947/000095012311014700/c11256e10vk.htm
[xxi] Company 10-K, accessed on July 20, 2020 at https://sec.report/Document/0001193125-12-049043/#toc283520_54
[xxii] Agreement and Plan of Merger of Ohio Power Company and Columbus Southern Power Company, filed in January 2012, accessed on September 2, 2020 at https://www.lawinsider.com/contracts/3KmzfWFIALI3wQNyQx0Lgw/ohio-power-co/agreement-and-plan-of-merger/2012-01-06
[xxiii] When the bonds are issued in multiple tranches of increasing tenors, we assume that principal amortization for successive tranches only commence once the previous tranche has been fully repaid. For bonds with tenors that extend beyond 2019, we use total utility revenues from 2019 to calculate the surcharge as a fraction of revenues.
[xxiv] e21 Initiative, *Performance-Based Regulation in Minnesota: A Decade of Progress*, June 9, 2020, accessed on July 14, 2020 at https://e21initiative.org/performance-based-regulation-in-minnesota-a-decade-of-progress/
[xxv] S&P Global Market Intelligence, "More regulators taking a look at COVID-19 impacts on utilities," April 27, 2020
[xxvi] Information collected from expert interviews.
[xxvii] Original data from Saber Partners; additional information collected by RMI team through S&P Market Intelligence platform. https://saberpartners.com/list-of-investor-owned-utility-securitization-rocrrb-bond-transactions-1997-present/

STATE OF MINNESOTA)
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COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA ELECTRONIC FILING

Tiana Heger of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 1st day of October, 2020, she served Minnesota Power's Report in **Docket No. E015/RP-15-690, E015/GR-16-664** and **E015/AI-17-568** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on E-Docket's Official Service List for this Docket were served as requested.

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Tiana Heger