UTILITY EARNINGS IN A SERVICE-ORIENTED WORLD

Optimizing Incentives for Capital- and Service-Based Solutions

By Advanced Energy Economy Institute

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Participating in key regulatory proceedings in targeted states to provide leadership and input to policymakers and regulators on electric utility industry changes required to support a viable utility business model that allows a high degree of distributed energy resources and empowers customers to become more engaged in their energy use to the benefit of the whole grid.

Facilitating detailed discussions and collaboration among diverse stakeholders who are interested in working together to accelerate reforms that lead to win-win outcomes.

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Lead Contributors

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Thomas D'Ambrosia – Thomas worked as an independent contractor for AEE Institute on this paper. His many years of regulatory and accounting experience provided invaluable insights that influenced the design and development of this paper. Thomas has over 30 years of experience at the New York Public Service Commission where he served as Chief of the Office of Accounting, Audits, and Finance. Thomas is now an independent consultant. AEE Institute appreciates Thomas' significant contributions in support of this paper, which went above and beyond expectations.

Kent Bond – Kent worked as an independent contractor for AEE Institute on this paper. This paper would not have been possible without the benefit of his sharp analytical mind, mastery of finance and accounting, and expertise with modeling. Kent is a CPA, has obtained his MBA, and has several years of experience building financial models for a multi-state utility. He currently works as a data analyst at a major investment bank. AEE Institute appreciates Kent's significant contributions in support of this paper, which went above and beyond expectations.

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* Review does not necessarily constitute endorsement of the paper.

Recent Changes to Federal Tax Law

The modeling and analysis of this paper reflects the changes to Federal tax law contained in Public Law 115-97 (unofficially the "Tax Cut and Jobs Act of 2017"). This law was passed in December 2017.

SUMMARY

Throughout the economy, companies are finding efficiencies and operational benefits by meeting their needs through services provided by third parties rather than investing in physical assets that they own and manage.[1] Utilities are no different. However, the trend toward services has faced some unique barriers in the investor-owned utility industry, as utilities have an issue in their underlying business model, imposed by regulation, that most other businesses do not.

In the current cost-of-service regulatory model, which has served the sector and customers well for many years, capital investments are a large driver of returns to utility shareholders. Utility investors are allowed to earn a rate of return on net invested capital (gross capital minus accumulated depreciation). In contrast, operating costs (such as fuel, labor, maintenance, and service expenses)[2] are generally passed through to customers in electric rates without the utility making any direct profits on them, although utilities remain incented to manage operating costs to reduce overall cost to customers, and also to manage profits between regulatory rate reviews.

Over the long term, however, services that can improve the utilization of, defer, or replace capital investments may have the effect of reducing opportunities for utilities to generate earnings. Because many new technologies are offered only as a service, utilities may be discouraged from using them. Realizing that both customers and utilities stand to benefit from equalizing the earnings opportunities between traditional capital solutions and service solutions that reduce capital investment needs, several state commissions have explored or implemented mechanisms to compensate for the bias toward capital investments that is inherent in cost-of-service regulation.[3]

Regulated utilities spend billions of dollars each year on infrastructure to meet their obligation to deliver safe, reliable, affordable service to customers in an environmentally acceptable manner. The majority of capital investments in the power grid today are related to reliability, replacement of aging equipment, accessing renewable energy, and the installation of environmental controls. A smaller portion, primarily capital investments related to capacity expansion and IT systems, presents an

[1] A common example is a company that decides to lease, rather than own, a fleet of vehicles. Examples within utility procurement are numerous, as explained later, but they include a utility contracting for cloud computing services rather than setting up a data center or a utility contracting for targeted demand response rather than upgrading distribution infrastructure.

[2] These costs are also interchangeably referred to as operations and maintenance ("O&M"), operating expenses, and opex.

[3] National Association of Regulatory Utility Commissioner's Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements, adopted November 16, 2016. See: https://pubs.naruc.org/pub.cfm?id=2E54C6FF-FEE9-5368-21AB-638C00554476

opportunity for deferral or replacement by a service solution.

We identified several different regulatory treatments that states are using or piloting for services that replace capital investments. Some of these mechanisms, such as capitalization of a service contract or the use of regulatory assets,[4] are available today without the need for changes in regulation. These mechanisms allow utilities to place "service assets" in their rate base and amortize them like capital investments. Other regulatory mechanisms require changes in regulations and are designed to provide financial incentives to utilities that better align their earnings with their ability to generate cost savings.

This paper utilizes financial models to explore the impacts of several different regulatory mechanisms for encouraging utilities to pursue service-based solutions. Based on this exploration, the paper makes some general recommendations for implementation.

The specific service-based solutions assessed in this paper are very different in type: cloud computing services, which take the place of utility investments in on-site computers, servers, and software; and distributed energy resources[5] (DER), which defer or avoid utility investments in distribution equipment and infrastructure by contracting for the services provided by customer- or third party-owned assets such as solar installations, battery storage, or demand response. Additional use cases exist that this paper does not model, such as energy efficiency programs or Power Purchase Agreements that replace utility-owned generation, but the same regulatory concepts generally apply.

For these two service-based solutions, we looked at five alternative regulatory mechanisms in comparison to two status quo mechanisms that represent common regulatory practice. The first mechanism, which we refer to as the Reference Case, reflects standard practice for recovering the cost of a capital investment by depreciating the asset in a utility rate base over a period of years (often 20 to 40). The second status quo mechanism, Service as O&M, reflects common practice for accounting for a service solution (in lieu of a capital investment) in which there is minimal opportunity for earning a return on the service expenditure. The other five alternative mechanisms are new options that aim to provide better outcomes through providing earnings opportunities on services. The five alternative mechanisms considered are as follows:

DER Incentive Adder ("DER Adder") – This option functions similarly to the Service as O&M option, except that the utility receives 4% of the total cost of the periodic payments for the service solution as an incentive to compensate for the utility's avoided earnings.

[4] Regulatory assets are costs or revenues that a regulatory agency authorizes and GAAP accounting rules permit a utility to place in its rate base, effectively treating it like a capital investment.

[5] We define DER broadly to include energy efficiency, demand response, distributed generation of all types, energy storage, microgrids, and electric vehicles and the associated charging infrastructure. These resources can be used individually or in combination to defer or avoid traditional utility investments.

Capitalization of a prepaid contract ("Prepaid Option" or "Prepaid Contract") – This option employs a prepaid asset, a commonly used form of cost recovery for utilities, which treats an expense similar to a physical asset by placing it into the rate base, amortizing it, and recovering it over time. In this case, a service payment would be pre-paid for a number of years and would be amortized over the length of the contract. The utility would collect its yearly carrying costs, including return for the investors' equity, based on any unamortized balances.

Non-Wires Alternative[6] Shared Savings ("NWA Option") – The NWA Option functions similarly to the Prepaid Contract because it is based on a prepaid service that the utility recovers as a regulatory asset. However, an additional earnings incentive is provided on top of earnings from capitalizing the prepaid contract to compensate for lower earnings when the service costs less than the Reference Case. The utility shares in 30% of the present value of the total savings when compared to the Reference Case. The shared savings are applied in equivalent increments on a yearly basis for the length of the service prepayment.

Modified Clawback Mechanism ("Modified Clawback") – This option is an adjustment to the net capital plant reconciliation, or "clawback," mechanism, which is used in some states to reclaim the unspent portion of a capital budget, plus the associated earnings, in the event that a utility does not spend its full capital budget. The Modified Clawback Mechanism leaves intact any portion of the capital budget that goes unspent because the associated investment was replaced with a service expenditure. Any positive difference between the original amount in the capital budget and the service cost paid through O&M is retained as profit. In the next rate case, the capital costs associated with the avoided project are removed from the capital budget and the O&M budget is increased to provide rate recovery for the service expenditure.

Pay-as-you-Go ("PayGo") – This option combines a number of features from the mechanisms outlined above. Under PayGo, the utility prepays a service expenditure for one year at a time and places the prepayment into the rate base as a regulatory asset. With authorization from the state utility commission, the utility would amortize these regulatory assets over a period greater than one year. In our model, the amortization rate, based on one-third the life of the service contract, is applied to the prepayments as a group. Thus, the regulatory asset would build year-on-year while simultaneously being amortized. In addition to these earnings from rate base, the utility receives a variable shared savings incentive proportional to the cost savings provided by the service option. For example, if the all-in costs of the service solution are 25% less than the Reference Case, the utility would take 25% of the total savings.

We also examined these regulatory mechanisms under three different scenarios: short-term replacement of a capital investment expected to last for five years; short-term deferral of a capital investment for five years;

[6] Non-Wires Alternatives (NWAs) are non-traditional solutions, such as DER, that replace traditional transmissions and distribution system investments, such as poles, wires, and transformers

and long-term replacement of a capital investment expected to last for 40 years. We further evaluated the regulatory mechanisms in two different cost scenarios, or cost cases. The first, the Equivalent Cost Case, assumes that the service solution costs are approximately the same[7] as the Reference Case capital investment in order to test how efficiently the mechanisms render costs to customers and provide earnings for the utility. The second, Lower-Cost Case assumes that the service solution costs 25% less than the Reference Case capital investment to measure the impact of the shared savings functions in some of the mechanisms.

The findings are encouraging. As the figures below show, when a service solution is available at equal or lower cost to customers than in the Reference Case (in net present value terms), the five alternative mechanisms in many cases also provide equivalent or greater earnings[8] to the utility – a win-win for consumers and utility shareholders. In the figures below, a "win-win" is when an option is both above and to the left of the Reference Case.

[7] Utility capital investments and third-party service solutions have different underlying costs, taxes, and other factors that make a direct comparison of total solution costs complicated. We explain this in more detail on page 40 in the section titled "Making an Accurate Comparison."

[8] The project NPV depicted in the figures is a calculation of value that puts earnings in perspective relative to the costs associated with generating those earnings. It depicts the value of a project to utility shareholders.

Figure A: Modeling Results for the Short-Term Replacement Scenario

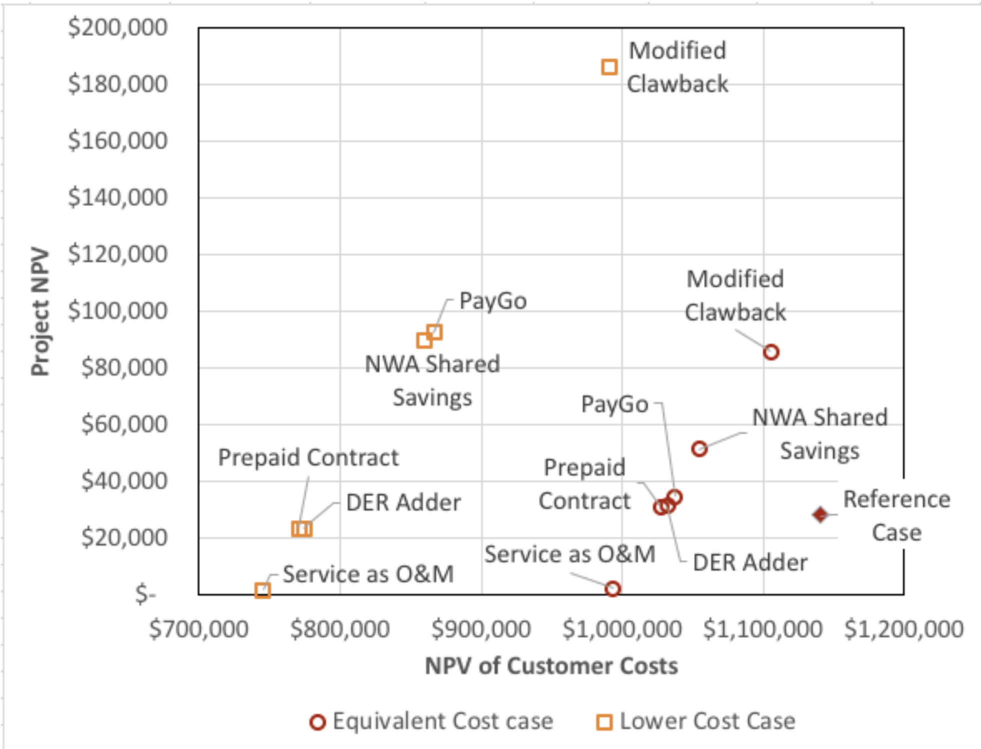


Figure B: Modeling Results for the Short-Term Deferral Scenario

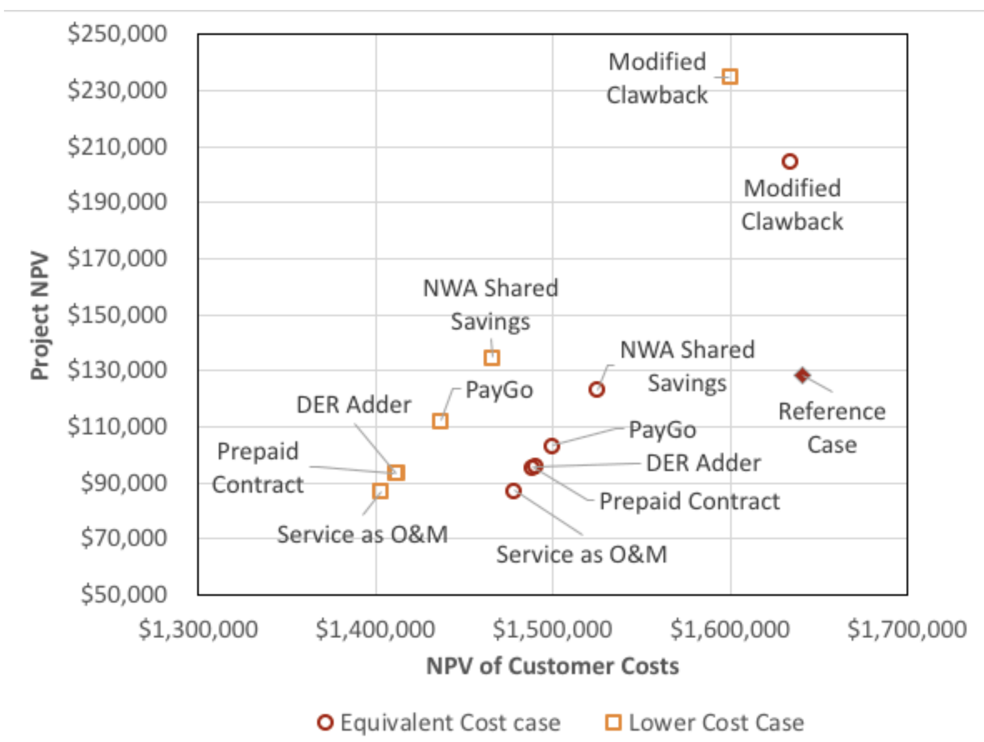
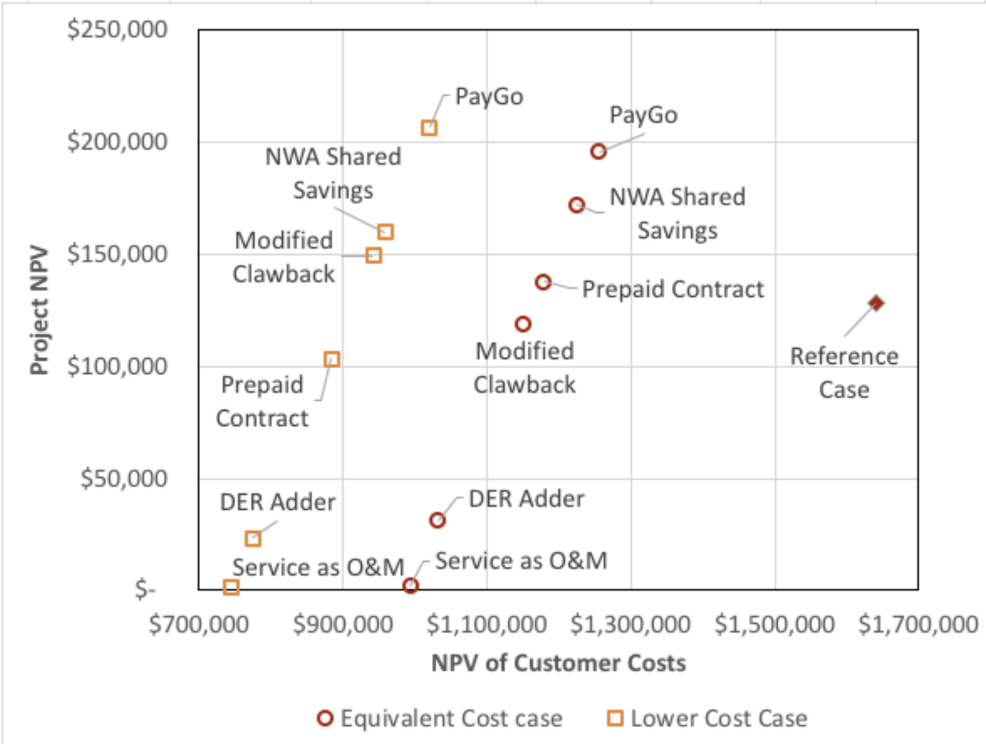


Figure C: Modeling Results for the Long-Term Replacement Scenario



While it is not entirely clear that any one option is the best performer overall (though there are clear leaders in specific scenarios), most of the options tested are better than business-as-usual in realizing cost savings for customers when there is a service available that is more cost effective than a traditional capital investment, as demonstrated by the Lower-Cost Case results. This indicates it would be beneficial to investigate these options – and perhaps others – in greater detail and refine them for more widespread implementation.

Our conclusion is that, however well cost-of-service regulation has served us over the past decades, it has remained relatively static while the rest of the economy is increasingly taking advantage of the benefits that a service-based model has to offer. We do not see this trend abating, and it may indeed accelerate, which makes it imperative for the utility regulatory model to be brought into alignment. With an approach that puts service-based solutions on equal footing with capital investments for utilities, customers will benefit from more cost-effective and feature-rich solutions that may not otherwise be pursued. At the same time, utilities will be rewarded for pursuing services that provide new benefits to customers and harness privately-owned resources that offset their own investments without fear that doing so will erode earnings for them and their investors. Finally, service providers will benefit from market opportunity, which will ultimately increase competition, drive innovation, and promote the continuous improvement of these services and the value that they deliver.

TABLE OF CONTENTS

INTRODUCTION

New Services for Utilities

As new technologies develop, they are increasingly being offered as services where the provider owns the technology, operates and maintains it, and guarantees an outcome or an output in the contract with the customer. This contrasts with the traditional model of the sale of the technology as a physical asset, where the maintenance, operation, and final outputs are the responsibility of the purchaser. Services take advantage of the significant experience of specialized companies in operating specific types of assets and can provide significant value compared to an ownership-based model. It may also provide a better way to address technological obsolescence, as shorter-term service contracts allow for renewal using the latest available technologies. Moreover, often these services can be delivered more effectively in a centralized fashion because the service provider pools assets and more efficiently utilizes capacity rather than each utility constructing enough capacity to serve its own needs.

Cloud computing is a good example of a service that embodies all of the benefits described above. For decades, utilities have deployed their own IT resources and servers, purchased software, and hired staff to manage and operate the systems. This requires a significant investment of onsite computing capacity and internal staff development to make all of the resources function properly. If, instead, the utility were to purchase cloud computing services or cloud-hosted software as a service (SaaS), with all of the security and IT infrastructure supplied by the service provider and its own network of partners and vendors, the utility could leverage the specialization and expertise of the provider and benefit from cost efficiencies through use of shared infrastructure (the provider's data center). Cloud computing also allows utilities to scale up or scale back capacity on demand, providing much greater flexibility than a system that is owned and operated by the utility. Making use of cloud computing also ensures that the systems are always up to date, will not become obsolete, and are easier to keep secure. However, for regulated utilities, if cloud computing is treated as a service expense, it replaces an earnings opportunity – the capital investment related to IT infrastructure and software upon which a utility can earn its regulated rate of return – with a service expense that earns the utility no return.

These principles that apply to cloud computing – scalability, flexibility, security, resource efficiency – often apply to other parts of the utility business. Various forms of non-wires alternatives rely on services that, in some cases, may effectively replace or defer utility capital expenditures. Take for instance a distribution transformer that is reaching its capacity limit due to growing peak demand in the summer. On one of the feeders served by the transformer, a large customer is considering purchasing a battery for reliability and to reduce their demand charges. The utility could contract for dispatch rights on the battery during the top summer demand hours, alleviating the need to invest in an expensive new transformer. The customer can make use of the battery during all other hours for energy price arbitrage, backup power, and demand charge savings. While the utility saves from purchasing an expensive transformer, it is in essence replacing that equipment and capital investment with a service contract for dispatch rights. The same scenario is applicable to a contract with a demand response provider, which can pay its customers to reduce peak demand and offset the need for a capital investment in a new transformer.

As we detail in this paper at length, the loss of earnings that a utility incurs by choosing more cost-effective, service-based options can be offset through a number of adjustments to the traditional cost-of-service model that aim to provide utilities with equivalent earnings.

Methodology

Given the potential benefits that could be derived from increased use of services by utilities, some regulators have been exploring how to encourage their adoption. Given that we wanted to compare, side-by side, various regulatory options that allow utilities to earn a return on services with the traditional cost-of-service model. Our analysis is not intended to determine which regulatory options are best, nor does it explore all the options that might be possible. The states that have adopted these options are forerunners, thinking creatively to address a problem for which there were no ready-made solutions. But now that several of these mechanisms have been developed and are in various stages of implementation, an in-depth analysis of these regulatory mechanisms could be useful to other states as they confront the same issue.

There have always been tradeoffs between capital and operating expenditures in utility planning and operations; however, when applied to new technologies of various types, these tradeoffs can become barriers to deployment. The services that are examined specifically in this study – cloud computing and customer or third-party owned distributed energy resources (DER)[9] – may provide new value in terms of functionality and cost-effectiveness. Cloud computing provides significant potential benefits to utilities by reducing hardware and software costs, increasing interoperability, and keeping current with the latest software development tools and cybersecurity standards. DER services provide for increased economic efficiency through leveraging a customer- or third party-owned resource that can also be operated to benefit the grid. For example, a private resource that was deployed to decrease one customer's demand charges can also be used to decrease peak system and distribution load, potentially saving all customers money.

In this paper, we do not assume that services will always be more cost-effective. However,

9 We define DER broadly to include energy efficiency, demand response, distributed generation of all types, energy storage, microgrids, and electric vehicles and the associated charging infrastructure. These resources can be used individually or in combination to defer or avoid traditional utility investments.

they may be more cost effective now than a traditional utility solution in some scenarios and are expected to increasingly become so in the future as new technologies continue to mature and decrease in cost. We also do not assume that utilities make their decisions based on earnings alone. Utilities take into account a wide variety of factors when selecting solutions and are genuinely concerned about the quality, reliability, and affordability of service that they provide to their customers. Nevertheless, existing regulatory incentives place utilities in situations where they may be faced with choosing between the interests of their customers and their shareholders. **The key question of this paper is, if there is value to be realized from a service-based solution, but current regulatory incentives prevent it from being realized consistently, what regulatory changes would ensure that this value is not left on the table?**

This paper aims to help answer that question by evaluating the financial performance of several regulatory options that provide earnings to utilities for utilizing service solutions. We developed a detailed cost-of-service financial model to project the performance of each option according to three different scenarios. These scenarios were meant to reflect the most common deployment circumstances for services. We also modeled each of the scenarios according to two cost cases: an "Equivalent Cost Case," which assumes the service-based options receive investment that is approximately equal[10] to a traditional capital solution (the Reference Case), and a "Lower Cost Case," where the cost of the service solution is 25% less than the Reference Case. We evaluated the financial performance of the options in each scenario utilizing two key metrics: total cost to customers and the project's net present value (project NPV) to the utility and shareholders.

Regulatory Options

Throughout the paper, we refer to the regulatory mechanisms as options. We identified several different options that states are using or piloting for services that replace capital investments. We have also devised one additional option that attempts to overcome some of the shortcomings found in the other mechanisms. Some options reflect current practice, while others attempt to equalize earnings for equivalent levels of investment. Some of the options provide further earnings opportunities from service solutions that are more cost effective than the Reference Case. These options are summarized below and detailed at length later in the paper.

Status Quo Options:

Reference Case – This option represents a traditional utility capital investment that is recovered in standard practice through depreciating an asset in the rate base. Cost recovery typically occurs over a relatively long period of time, often 20 to 40 years or more. This is the standard solution against which all of the other options are compared.

Service as O&M – This option represents standard practice for rate recovery of service

[10] See P. 39, Making an Accurate Comparison

contracts. In this situation, the cost of the service is paid periodically as an O&M expense out of the utility's working capital. The working capital is funded out of the rate base, but it is assumed to be recovered quickly from rates, so only a small fraction of such costs is carried by investors.[11] As such, the earnings for investors from the equity they invested to fund the working capital is very small.

Alternative Options:

DER Incentive Adder ("DER Adder") – This option functions similarly to the Service as O&M option, except that the utility receives 4% of the total cost of the periodic payments for the service solution as an incentive to compensate for the utility's avoided earnings. In this option, utility earnings are derived mostly from the 4% incentive and to a much lesser degree from earnings associated with the use of working capital.

Capitalization of a prepaid contract ("Prepaid Option" or "Prepaid Contract") – This option employs a prepaid asset, a commonly used form of cost recovery for utilities, which treats an expense similar to a physical asset by placing it into the rate base, amortizing it, and recovering it over time. In this case, a service payment would be pre-paid for a number of years and would be amortized over the length of the contract. The utility would collect its yearly carrying costs, including return for the investors' equity, based on any unamortized balances. The term of this recovery is typically shorter than the recovery period in the Reference Case, for example five to ten years.

Non-Wires Alternative Shared Savings ("NWA Option") – The NWA Shared Savings option functions similarly to the Prepaid Contract because it is based on a prepaid service that the utility recovers as a regulatory asset. However, an additional earnings incentive is provided on top of earnings from capitalizing the prepaid contract to compensate for lower earnings when the service costs less than the Reference Case. The utility shares in 30% of the present value of the total savings when compared to the Reference Case. The shared savings are applied in equivalent increments on a yearly basis for the length of the service prepayment.[12]

Modified Clawback Mechanism ("Modified Clawback") – This option is an adjustment to the net capital plant reconciliation, or clawback, mechanism, which is used in some states. Normally, the mechanism "claws back" the unspent portion of a capital budget plus the associated earnings, in the event that a utility does not spend its full capital budget. Instead, the Modified Clawback Mechanism leaves intact any portion of the capital budget that goes unspent because the associated investment was replaced with a service

[11] Typically a FERC formula is used for operating expenses which places 1/8 of such expenses in rate base for purposes of applying the utility's allowed return.

[12] This deviates from the NWA mechanism as implemented in New York. In New York, the incentive is based on a 30% share of net benefits as determined by a Benefit Cost Analysis that also includes the cost of carbon. In order to simplify the model, we opted to provide the incentive on a direct cost savings basis rather than as a share of net benefits.

expenditure. In this case, the utility pays for the service expenditure out of its O&M budget without additional rate recovery. Normally, the utility would be at risk of losing money it if exceeds its projected O&M expenditures; however, the capital budget that has not been "clawed back" compensates for the higher O&M expense. Any positive difference between the original amount in the capital budget and the service cost paid through O&M is retained as profit. Thus, the utility retains all cost savings while this mechanism is in effect. After the next rate case, the capital costs associated with the avoided project are removed from the capital budget and the O&M budget is increased to provide traditional rate recovery for the service expenditure. From this point on, customers retain all of the savings associated with the lower cost service option and the utility receives no further earnings.

Pay-as-you-Go ("PayGo") – This option combines a number of features from the mechanisms outlined above. Under PayGo, the utility prepays a service expenditure for one year at a time and places the prepayment into the rate base as a regulatory asset. With authorization from the state utility commission, the utility would amortize these regulatory assets over a period greater than one year. In our model, the amortization rate, based on one-third the life of the service contract, is applied to the prepayments as a group. Thus, the regulatory asset would build year-on-year while simultaneously being amortized. In addition to these earnings from rate base, the utility receives a variable shared savings incentive. The percentage of the savings that the utility retains is proportional to the cost savings provided by the service option, subject to a 50% sharing cap. For example, if the all-in costs of the service solution are 25% less than the Reference Case, the utility would take 25% of the total savings.

We also considered one additional option, the UK's totex mechanism, but due to questions about its compatibility with U.S. accounting rules, we did not model it. We have provided a thorough explanation of totex in the paper and the potential compatibility issues with its application in the United States.

Deployment Scenarios

To test the financial performance and cost effectiveness of the options, we modeled them in three different scenarios meant to simulate the conditions of some of the most common situations where a utility would employ a service solution instead of a capital investment. These scenarios are necessary to capture three important differences, and all of them are associated with the technological differences underpinning these services:

- The first difference is whether the service *defers* or *replaces* the need for the utility capital investment. Different calculations are needed for determining the value of avoiding an investment completely versus determining the value of merely delaying a capital investment for several years.
- The second difference is the length of the expected lifespan of the avoided utility investment. The longer the utility depreciates an investment, the larger the carrying costs and therefore the investor's returns over the lifespan of the capital investment.

- The third difference is the type of technology to be used in the avoided utility investment (the Reference Case). The type of technology (e.g., software vs. distribution transformer) matters because different depreciation rates for tax purposes are applicable under federal tax code. These depreciation rates have an impact on both the cost of the Reference Case and the earnings that the utility derives from it. The scenarios are outlined below.

Short-term Replacement – This scenario depicts a service contract of five years that completely replaces a utility solution that is also expected to last five years. The model only computes the earnings and costs for five years, but the scenario could be repeated again after the fifth year to get a longer projection of the financial impact. An example of a service solution that fits this deployment scenario is a cloud computing service that replaces the need for an on-site solution.

Short-term Deferral – This scenario shows the impact of a service solution that defers the need for the utility to invest in a traditional distribution solution by five years. In year six, the service contract ends and a traditional utility capital investment is made, which is then depreciated over 40 years. The model provides a detailed breakdown of the costs to customers, the earnings for the utility, and the payments to third-parties (if applicable) for the first 42 years, then provides a terminal value to project years 43 through 47. NWA solutions, such as a battery used to provide capacity relief for a transformer, fit this deployment scenario well.

Long-term Replacement – This scenario shows the impact of a service that replaces the need for a capital investment over a period of 40 years. In this scenario, the service contract is in effect for 40 years and the utility capital investment is never made. This estimates the financial impact over the long term if the service is able to completely replace the need for a traditional utility investment. NWA solutions, where the service is able to fully replace a long-lived, traditional utility investment, fit this deployment scenario well.

Additionally, we modeled each scenario according to two different cost cases. In the Equivalent Cost Case, the investment in services for each option, or a capital investment for the Reference Case, is assumed to be the equivalent of $1 million in net present value, with the exception of the Short-term Deferral scenario. In the Short-term Deferral scenario, the Equivalent Cost Case uses the annual cost of a utility $1 million investment in a 40-year distribution asset, as it would not make sense to spend $1 million for a five-year service solution that could have been alternatively invested in a capital solution lasting for 40 years at the same cost. The second cost variation is the Lower Cost Case where we assume the cost of the service solution is 75% of the service cost in the Equivalent Cost Case. Creating two different cost cases that remain constant for each scenario allows us to better evaluate the impact of the options on costs to customers and utility earnings. The Equivalent Cost Case attempts to create a level playing field so that costs and earnings associated with each option can be compared to the Reference Case. On the other hand, the Lower Cost Case is meant to test the performance of the shared savings mechanisms. Because of this, the cost of the Reference Case is never reduced so that it can serve as a single point of comparison.

Modeling

The model we developed projects a hypothetical utility's detailed revenues, expenses, debts, interest payments, rate base, earnings, taxes, and cash flows for each year for a period of up to 42 years (with a terminal value used to estimate further years as needed). The model projects these detailed cash flows for each option given the different assumptions contained in each of the three scenarios and two Cost Cases. In total, the model provides results for each option six times (i.e., three scenarios times two cost cases).

Before providing full details of the modeling and analysis, the paper provides relevant background information on the utility business model and accounting rules and describes the regulatory options in greater depth.

BACKGROUND

The Regulatory Model and Utility Profit Drivers

The current form of cost-of-service regulation has been around for many decades and has served both customers and utilities well for many years. Utilities deploy capital that they raise from lenders and equity investors to make the long-term investments needed to provide electricity to customers: poles, wires, transformers, generators, etc. Over time, utility customers pay for the cost of these investments in rates. Regulators set rates that allow utilities to recover the cost of their initial investment (yearly depreciation) plus the cost of debt and return on equity (the cost of capital or carrying costs) on the undepreciated amount. These carrying costs reflect the return lenders and investors require for providing the capital and account for both the time value of money and the risk, small though it may be, that the capital may not be repaid to lenders and that investor equity may decrease in value. As utilities enjoy some of the lowest risk profiles and best credit ratings in the economy, they can borrow and provide returns to investors at relatively low rates. Thus, the near certainty of recovery of the utilities' capital investments and the associated lower cost of capital provides a tangible benefit to consumers in the form of lower rates.

The primary way that utility shareholders benefit is that regulators usually afford investors an opportunity to earn a competitive rate of return on their equity that is marginally higher than the shareholder's expected return, which is based on the return provided by other companies with a similar risk profile in the economy.[13] This is part of what makes utilities an attractive investment. If regulators provide a return that is lower than what other companies provide, investors incur opportunity costs. Raising new capital would become expensive for the company and would decrease the value of equity for existing shareholders, harming the ability of utilities to make necessary investments in the long run. However, allowing investors to earn a rate of return on equity above shareholders' expected return motivates utilities to increase their capital investments as it increases shareholder value. As utilities invest more in transformers, wires, and other plant, shareholder value increases and customers benefit from a modern and reliable electric grid. While setting the allowed return on equity to the exact amount investors require for a utility's level of risk would theoretically leave a utility indifferent toward capital investments, it

[13] This concept is explained in much greater detail in a paper published by America's Power Plan. It is recommended reading for anyone interested in greater detail the role of return on equity and cost of equity in creating value for shareholders. See: You Get What You Pay For: Moving Toward Value in Utility Compensation. By Steve Kihm, Ron Lehr, Sonia Aggarwal, and Edward Burgess. Available at: http://americaspowerplan.com/wp-content/uploads/2016/07/CostValue-Part1-Revenue.pdf

would also provide no real value to shareholders for investing in a utility relative to their other options. In order to attract new capital on favorable terms, utilities need to provide shareholders with value, and therefore a reasonable premium on the allowed return on equity over the return on similarly risk-rated equity in the market is necessary.

Utility rates are based upon the forecasted cost of service, which includes revenues, capital expenditures (and a return of and on capital), operating expenses, and taxes. In addition to the return on capital expenditures, utilities can also create earnings by closely managing the elements of their forecast cost of service. Operating expenditures,[14] such as maintenance, salaries, fuel, and other necessary operating costs are recovered in rates, but unlike capital expenditures, utilities do not earn an explicit rate of return on them. Instead, as an incentive to manage its costs, operating expenditures that vary from the level provided in a utility's current rate plan affect earnings. To the extent that a utility can manage and reduce its operating expenditures, it can achieve additional profits in the short-term (between regulatory rate reviews or rate cases – the process of resetting utility rates) while consumers benefit from these efficiencies in the long-term. Conversely, operating costs that exceed the rate forecasts are paid out of the utility's earnings and are not passed on to customers. Importantly, these latter incentives are available only on a short-term basis, until the utility's next rate plan is implemented.

Additionally, many states have an Earnings Sharing Mechanism (ESMs) that allows a utility to retain all or a portion of unspent operating funds as profit to incentivize efficient use of operating expenditures; commonly referred to as 'regulatory lag.' In some cases, these unspent funds can be paid out in dividends or invested in capital and earn a return, thus expanding the rate base without special regulatory approval. As a result, utilities work to minimize their operating expenditures, both to avoid the risk of expenditure overruns eating into their profits and to potentially retain some of the unspent operating funds as profit.

Finally, some states are in the process of developing Performance-Based Regulation (PBR)[15] to better align utility earnings opportunities with state goals and customer interests. Some states, such as New York and Rhode Island are implementing PBR in the form of Earnings Adjustment Mechanisms (in NY) and Performance Incentive Mechanisms (in RI), which are adjustments to earnings based on performance on broad metrics relating to achieving state energy goals such as system efficiency, energy efficiency, customer

[14] Depending upon the method of ratemaking employed by the state commission, the utilities can also potentially earn additional profits through reducing capital expenditures (capex) below levels used to set rates. However, in some states (e.g., New York), the utility commissions claw back the earnings impacts of unspent capex (capex clawback—discussed later). Such clawbacks are employed in order to ensure safe and adequate service will be preserved through sufficient investments in the network.

[15] PBR generally refers to a broader range of modifications to or departures from traditional rate making. Here we focus specifically on performance metrics and incentives.

engagement, and interconnection performance.

PBR is often intended to provide incentives to utilities to choose non-traditional (non-capital) solutions that would meet state energy goals and also achieve earnings that would otherwise not be achieved. However, PBR should be understood as an outcome-based incentive and not as an input incentive, the latter being the financial signal that determines how money is invested into the system, which is the focus of this paper. PBR provides incentives for specific outcomes but does not directly address the incentives for how the utility invests and achieves the outcomes. If PBR provides earnings for non-capital solutions, it does so only to the extent a specific outcome results from the deployment of a non-capital solution. A utility would still have a preference for meeting PBR targets through capital solutions, all other things held equal. PBR, therefore, is better suited as an incentive mechanism to remove the threat of a utility eroding its own financial position through achieving certain goals, such as driving down peak demand and decreasing rate base over the long-term, rather than correcting for existing input incentives and encouraging the selection of the most cost-effective solutions.

When cost-of-service regulation was designed, it made sense to focus incentives on minimizing operating costs. System needs could usually only be fulfilled with a few types of capital investments (wires, generators, transformers, etc.), while operating expenditures were generally seen as overhead. Regulators were responsible for making sure the system was built to be reliable with the lowest possible capital investment.

Today, due to innovations in technology and business models, utilities have far more options for meeting their operating goals of reliability, safety, cost-effectiveness, and quality of service. In some cases, operating expenditures for services procured from third-party providers (such as cloud computing and DER) may more cost-effectively fulfill system needs than traditional utility capital investments.[16] But shifting spending from capital investment to operating expenses runs counter to the incentive/earnings structure that still predominates in the sector and favors fixed, long-lived assets.

This presents a dilemma as utilities can take a financial hit in two ways when they replace capital with a service. Utilities take very seriously their responsibility to serve customers with safe and reliable power, but they also appropriately take seriously their duty to deliver earnings to their shareholders. Thus, the regulatory framework at times may make utilities choose between serving the best interests of their customers and serving the best interests of their shareholders. We say this though, recognizing that each utility's capital investment plans are reviewed, and in many

[16] It should be noted that utilities already extensively used third-party providers to operate, maintain, and build their networks (labor, contractors, consultants, service providers, etc.). The issue here is whether it is more cost effective to use the service contract of a third-party provider (operating expense) rather than to build capital assets.

states approved, by regulators. For the reasons described above, utilities lack the right incentives to continually minimize their capital costs, especially if the reduced capital costs are accomplishing through an increase in operating expenses (which do not earn a return); and especially when those expenses are not built into rate forecasts.[17]

The goal of the regulatory reforms that are the subject of this paper is to level the playing field for the utility so that it can optimize among all potential expenditures, whether they are for capital investments or service contracts, for the ultimate benefit of customers. Utilities know their own systems better than anyone and are in the best position to leverage their knowledge to seek out efficiencies. But without the necessary financial motivation, the current system relies on the regulatory process without complete information to identify and attempt to enforce new efficiencies. Resolving these conflicts inherent in the system should thus not only benefit customers and utilities, but also ease the burden on regulators.

Utility Accounting and Implications for Service-based Earnings

In discussing the utility business model, it is necessary to understand accounting rules applicable to rate regulated utilities. Utilities need to comply with two different accounting standards, the Uniform System of Accounts (USofA), established by the Federal Energy Regulatory Commission (FERC) and adopted (and sometimes modified) by state utility commissions, and the US Generally Accepted Accounting Principles (GAAP), adopted by the Securities and Exchange Commission. Each serves a different purpose.

FERC established the USofA to create uniformity in reporting and to provide FERC with the right information so that it can carry out its duty of ensuring that the cost-of-service rates of jurisdictional utilities are just and reasonable. GAAP was created to provide standards for the financial statements of public companies. GAAP therefore is meant to increase transparency and uniformity in public financial statements for the benefit of investors, while USofA is meant to provide energy regulators with sufficient and accurate information to perform their oversight duties.

Both USofA and GAAP (for utilities through Accounting Standards Codification ASC 980 – Regulated Operations) were developed with the prevailing cost-of-service model in mind for utilities. However, USofA offers far more flexibility, and is more important to regulators

[17] The actual impact can vary based on whether there is a clawback mechanism. If there is no clawback mechanism, then the loss resulting from the unplanned increase in operating expenses may result in compensatory savings from avoiding an investment from the capital budget, and a portion of the resulting savings can be retained by the utility as earnings. If the capital budget savings is greater than the yearly operating expense, then the utility increases its earnings. But this is temporary until rates are reset in the next rate case. The lack of a clawback mechanism in this case functions much like the modified clawback mechanism that we describe below.

and this discussion; however, the requirements and consequences of ASC 980 should be considered. While GAAP requires conformity with a single system of standards and guidelines, state legislatures and regulatory commissions are responsible for adopting and applying USofA to their own purposes. This is good, because regulatory approaches that depart from existing practice may require new interpretations of USofA.

One way to characterize the difference between GAAP and USofA is that USofA is the primary language of utility accounting and provides the basis for establishing utility incentives through the ratemaking process. GAAP is a secondary language into which a utility's financial metrics can be translated for the benefit of the capital markets.

FERC has been clear about its view that USofA, not GAAP, is the key language for the regulatory process. In response to an assertion that utilities must first adhere to GAAP before implementing FERC's directives, FERC strongly disagreed. It stated:[18]

> To carry out its responsibilities under the Federal Power Act (FPA) and the Natural Gas Act (NGA), the Commission has been given authority to prescribe accounting and financial reporting requirements for jurisdictional companies. The Commission, for ratemaking and other purposes, needs financial statements that allow it to determine the current cost of service and to monitor past performance under approved rates. If GAAP conflicts with the accounting and financial reporting needed by the Commission to fulfill its statutory responsibilities, then GAAP must yield. GAAP cannot control when it would prevent the Commission from carrying out its duty to provide jurisdictional companies with the opportunity to earn a fair return on their investment and to protect ratepayers from excessive charges and discriminatory treatment.

Similarly, states have significant authority to regulate the rates and charges of utilities and to provide the opportunity to earn a fair return. The Federal Power Act defers to state jurisdiction in matters that it has not defined as interstate commerce.[19] Most states voluntarily adopt USofA as published by FERC,[20] but state commissions have the flexibility to create regulations necessary to fulfill their responsibilities. While implementation will require less change if new regulatory mechanisms are compatible with existing accounting standards, these standards are not limitations on state authority. If a state commission believes that it can better protect customers and improve the way utilities earn a fair return through regulatory changes that are incompatible with USofA and GAAP, it has the authority to fulfill its responsibilities; however, as explained below, such departures should be avoided.

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[18] FERC Order No. 552, Issued March 31, 1993.
[19] 16 U.S. Code, Chapter 12, §824
[20] USofA is mandatory for only those units of utilities that are under FERC's jurisdiction, such as transmission operators. Code of Federal Regulations, Title 18, Part 101.

Since utilities are natural monopolies, their rates are regulated by an independent third-party (regulatory commission). Utility rates are generally based on a 'just and reasonable' standard and approximate the utility's cost of service. This aspect of rate regulation creates a unique economic distinction between utilities and entities whose prices are set based on market forces. As a result, ASC 980 was developed to address such differences between rate-regulated and other firms.

ASC 980 provides financial accounting guidance for rate-regulated utilities. It addresses accounting for revenues, expenses, assets and liabilities recorded by rate-regulated utilities. To the extent that actions/rate decisions ordered by regulators provide for accounting treatment that differs from traditional accounting, regulatory assets or liabilities are created to comply with commission orders and record these differences. For example, a commission may allow the recovery of large storm restoration expenses over a long period of time to smooth rates. Normally, under traditional accounting such costs would be charged in one year, but the action of the commission to allow extended recovery enables the utility to record these costs on its balance sheet as regulatory assets.

The impact of the application of ASC 980 can be very significant. For example, in New York, it was estimated that "in 2014, utility assets in New York included over $4 billion of regulatory assets, or 24% of utility equity."[21]

In order for a utility to apply ASC 980, it must meet three criteria: 1) rates are established by an independent third party, 2) rates are designed to recover the cost of service, and 3) the utility has the ability to charge and collect rates that will recover its costs. Failure to meet these criteria would mean that the affected utility would no longer be able to apply ASC 980.[22] The discontinuance of the application of ASC 980 could result in the write off of regulatory assets and write down of plant for SEC reporting purposes.[23] The impacts of this on utility financial statements could be significant. The resulting impacts on investors upon whom the utilities rely for capital are difficult to assess and likely will depend upon the magnitude of the write downs and the specific circumstances that lead to the write down. Thus, incentive or ratemaking plans developed to address the optimization between capital and service expenditures should consider the utility's ability to continue to meet the criteria of ASC 980.

[21] See footnote 43 on page 43 of the New York State Department of Public Service Staff White Paper on Ratemaking and Utility Business Models, dated July 28, 2015.

[22] ASC 980 can also be discontinued for example under deregulation, increasing competition that limits the utility's ability to sell services at regulated rate levels, or regulator's resistance to approving rate increases.

[23] Write down of plant would potentially result from cumulative difference, if any, between depreciation recorded based on rates and lives approved by the regulator and depreciation that would be recorded by entities in general (e.g., recovery of accelerated depreciation) and certain capitalized costs such as allowance for funds used during construction (AFUDC).

Cost-of-service regulation is a critical principle in ASC 980. Rates should be developed to allow the utility to recover its cost of service and a reasonable rate of return. Rate plans that would cause a large disconnect between the utility's revenues and the underlying cost of service would also call into question whether ASC 980 applies.

Probably the most significant area where utility accounting differs from unregulated businesses is the ability of the utility to defer (i.e., capitalize) certain operating expenses that would otherwise be categorized as expenses under GAAP. These regulatory assets may be recorded on the balance sheet and amortized together with a reasonable rate of return on the unrecovered balance, if their recovery is "probable." Evidence of recoverability is usually found in rate orders approved by the relevant utility commission. In addition, the regulator's track record on recoverability of deferred costs should also be considered. A utility cannot simply rely upon the existence of a rate order authorizing deferral of a cost; it must also be able to show that the amortization of the deferred cost is included in the cost of service (i.e., revenue requirement) and that the unamortized balance is earning the allowed rate of return. If these criteria are not met, the deferred cost would need to be written off.

Another area relevant to the discussion of optimization between capital and service expenditures is the recording of alternative revenue programs. In addition to traditional billing based on cost-of-service revenue, regulators may also authorize such incentive programs that provide for additional billings (incentive awards such as NWA shared savings) if the regulated utility achieves certain objectives, such as reducing costs, reaching specified milestones, or improving customer service. These types of programs enable regulated utilities to adjust rates in the future (usually as a surcharge applied to future billings) in response to past activities or completed events. These alternative revenues may be recognized by the utility if they are established by an order of the regulatory commission, if the amount may be objectively determined, and if the additional revenues will be collected with 24 months following the end of the annual period in which they are recognized. Thus any alternative revenue plan developed here should consider these rules.

The various approaches/options discussed and analyzed in this paper will rely upon incentives in some form or another and perhaps some form of deferral accounting/creation of regulatory assets or liabilities. As noted above, regulatory accounting would accommodate such approaches. However, it would also be preferable for the associated financial accounting impacts of the proposed options be compatible with GAAP. It is our expectation that based on the above discussion of GAAP accounting, that there are no potential issues or concerns with utilities continuing to apply ASC 980 for financial accounting purposes so long as the rate actions of regulators are approved in an order and included in the cost of service.

REGULATORY OPTIONS

Desired Outcomes from New Regulatory Options

The following is a list of goals we had in mind while reviewing the mechanisms and that we used to guide our recommendations at the end of this paper:

Promoting earnings neutrality between capital and service solutions: As explained above, capital investments provide utilities with earnings while service solutions generally do not.[24] This provides an incentive for the utility to prefer capital solutions over service solutions rather than to consider them equally based on the merits of their costs and benefits. Creating earnings neutrality between capital and service solutions would therefore benefit customers by allowing the utility to consider the merits of a technology or solution first.

Allowing the utility to share in the savings it generates for customers: Even if regulation can achieve earnings neutrality, the utility would still stand to earn more by choosing a higher cost option, be it a capital or service-based solution. For this reason, some mechanism allowing for shared savings should be employed. Shared savings is preferred as it allows the utility to earn based on the amount of savings delivered. Therefore, a utility needs to maximize savings to customers in order to maximize its own incentive. This better aligns utility and customer interests.

Ease of implementation: Any regulatory mechanism should aim to avoid conflicts with accounting practices, taxation rules, and minimize workload for regulatory commissions and utilities. It should also minimize the potential for gaming.

Broad applicability across investment scenarios: A regulatory mechanism may in some cases work for one type of service solution, but not for another. As we discuss later, this issue arises mostly out of the differences in expected useful lives of different types of investments. Ideally, options should work for both short-term and long-term service solutions.

We have selected four different Options in use in different states and have developed a fifth option that attempts to overcome some of the drawbacks associated with multi-year prepayments employed in two of the other options. A description of our model and how we evaluated these options is provided later.

[24] We consider the earnings on working capital in the rate base associated with an increase in service expenditures to be *de minimis*.

Description of Regulatory Options

1. REFERENCE CASE

We developed a utility Reference Case in which the utility makes a capital investment of $1 million in present value under three scenarios. We assumed scenarios in which the utility's capital investment has lives of 5 and 40 years and calculated the utility's earnings and cash flows for each scenario. These scenarios are described in greater detail in the modeling and analysis section.

When considering the Reference Case, we find that there are several pros and cons. Among the main advantages of the Reference Case is the certainty and predictability of earnings to the utility, which serve to reduce its cost of capital. Some have argued that the incentives inherent in capital spending have produced the most reliable and resilient network. It is also a system that is obviously very familiar to regulators, utility management, and investors. As such regulators are familiar with reviewing and analyzing capital budgets, and in some instances have disallowed capital spending that was found to be imprudent. Thus, some argue that this system also protects customers.

However, the Reference Case has its disadvantages, besides the capital vs. service expenditure dilemma. There may be an inherent bias in the Reference case for increasing capital investment, which may not always produce the most efficient system. However, this bias for capital investment can be mitigated by the regulatory oversight of utility investments, and the need to demonstrate to regulators that such investments are appropriate. Also, there are indirect costs associated with capital investment which may not be considered when looking at the "all-in" cost of an investment, such as property taxes, insurance, and maintenance.[25] There is also risk to customers if there are cost overruns. To the extent there are cost overruns, they would be included in rate base in the next rate case, and subject to regulatory review. Finally, some have argued that the current system does not encourage innovation that could be brought if third parties were more involved in the network.

2. SERVICE AS AN O&M EXPENDITURE ("SERVICE AS O&M")

We have also included in our model the standard approach of recovering the cost of a service solution as an O&M expense. As discussed above, utilities do not earn an explicit return on service expenditures as they do with capital expenditures. Technically in the ratemaking process, utilities do earn on a working capital allowance for service expenditures but that contributes a relatively small amount of earnings.[26] Thus when we modeled the case of service expenditure vs. a capital investment, the choice was clear for the

[25] The analysis here attempts to capture these indirect costs.

[26] A cash working capital allowance is computed by 1/8 of operation and maintenance expenses (O&M) which then earns the utility's allowed rate of return. This is commonly referred to as the FERC formula.

utility. The capital investment produced significantly higher earnings. Under this option, when a utility chooses a service solution over a capital solution, it incurs a substantial opportunity cost.

There are a few benefits from this option. Assuming that the utility chooses the service over a capital solution, the customer captures nearly all of any savings realized. There are no financing or carrying costs borne by the utility, making this option a leader in terms of minimizing costs to customers. Also, most services are provided with contracts that have performance guarantees. If the service provider experiences cost overruns or the quality of the service is poor, it is the service provider that bears the cost of overruns and performance penalties. This transfers the risk off of utility customers.

3. DER INCENTIVE ADDER ("DER ADDER")

The California Public Utilities Commission (CPUC) is piloting a different method for compensating utilities for avoided earnings on NWA expenses. Instead of capitalizing the expense as a regulatory asset, California provides an incentive to the utilities that amounts to 4% of the value of the service expense which is passed on to customers via an automatic adjustment mechanism. This is meant to represent the value of the foregone earnings to shareholders. There were differing justifications cited in the proceeding that established the pilot for the 4% level. Some argued it would represent the forgone economic earnings relating to the difference between the shareholder's required returns, or cost of equity, and the allowed return on equity.

This incentive approach is a simple solution that aims to provide earnings on a service expense as an offset to the earnings forgone in a capital expenditure. However, as the incentive is based on the cost of the service expense rather than the avoided investment, the utility still has the potential to forgo greater earnings by choosing a more cost-effective solution. The incentive also provides no means to share the savings associated with an avoided expenditure. Further, as detailed further below, our modeling indicates that the adder is less effective at providing value in long-term scenarios, whereas the adder provides value on a project NPV basis that is equivalent or greater to the Reference Case for capital deferrals or replacements that are five years or less. As the adder is a simple and flexible approach, this option is a good candidate for short-term service solutions.

A chief disadvantage of this approach is that it requires the utility to identify which expenses qualify for the markup and which do not. This earnings opportunity creates an opening for the utility to potentially overstate the types and amounts of expenses that qualify for incentive treatment. This will place extra burdens on regulators to establish rules and provide oversight over this process.

4. CAPITALIZATION OF A PRE-PAID SERVICE CONTRACT ("PREPAID OPTION" OR "PREPAID CONTRACT")

Perhaps the simplest solution is to pre-pay the total cost of a service contract for a specified term, create a regulatory asset, and place this asset into the rate base. This would allow the utility to depreciate the contract over a number of years and collect carrying costs (which include the shareholders' return on equity) on the undepreciated amount until the contract is fully depreciated. In this case, the pre-paid contract is treated like physical assets in the utility's rate base.

Arguably, this is only a minor departure from the current regulatory framework, and for some types of services, would not require any adjustments to regulations or accounting practices. When the New York Public Service Commission (NY PSC) granted specific regulatory approval for capitalizing a pre-paid multi-year lease for software, it phrased its approval in such a way that indicated it was confirming an existing capability under accounting rules rather than providing a new capability.[27] The pre-payments could also be booked as regulatory assets, which are commonly used in many states where large expenses are paid but then carried by the utility (with carrying costs) in order to avoid a significant, short-term impact on rates. Examples of this are costs related to plant decommissioning or storm restoration. Under USofA, utilities may place services into one of several different accounts. For instance, cloud computing can be placed in USofA Account 303 which is reserved for Miscellaneous Intangible Plant. Another example is USofA Account 165 which is reserved for prepaid contracts.

There are advantages and disadvantages to pre-paid contracts. Among the advantages is that they transfer the operating and construction risks to the third party. In addition, unlike the utility capital option, a prepaid contract would have no additional indirect costs.[28] Also, third parties may achieve synergies and further economies of scale with their other customers, thus enabling savings when compared to utility stand-alone projects. For state regulators looking for an easy first step to resolve the impact of lost earnings to utilities when they choose a service solution rather than a capital investment, this capitalization approach is a good option from an administrative perspective because of its existing uses in other similar situations.

While there are several advantages, the prepaid approach is subject to less favorable tax treatment. Pre-paid contracts (other than for software) will likely have limited tax benefits available (such as accelerated depreciation); the costs will be deductible for tax purposes only as they are expensed each year. For software, straight line tax depreciation with an accelerated tax life of 36 months is used. Prior to the federal tax reform passed in December

[27] New York Public Service Commission, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, p. 104. May 9, 2016. Case 14-M-0101

[28] They would be built into the contract price.

2017, pre-paid contracts and regulatory assets were subject to a further disadvantage compared to capital investments. Capital investments were eligible for bonus depreciation that lowered costs to customers (and also lowered utility earnings through the bonus depreciation's downward impact on rate base). The loss of bonus depreciation for utility property in service after September 2017[29] increases its total cost to customers and places capital investments on more level terms with pre-paid contracts and regulatory assets.

Second, assuming the capital investment and the pre-paid service contract are similar in costs, the utility will be neutral to either option; however, if the service contract offers significant savings relative to the capital investment, the utility may lack motivation to pursue that option as it will decrease the utility's opportunity for earnings. Other regulatory approaches, described below, attempt to share some of the cost savings with the utility as an incentive for the utility to pursue the cost saving solution.

Third, the lifespan of the regulatory asset has significant impact in determining the total utility returns as the utility's rate base is tied to the depreciable life of the asset. If the contract is only for three years, the rate base value will depreciate at 1/3 per year. Compare this to a 30-year asset, which will depreciate at 1/30th per year. As utilities earn their carrying costs (which includes investor return) yearly on the unamortized balance, a shorter lifespan produces lower earnings for the same investment amount. Said another way, the same amount of initial investment can provide a larger amount of return over time if it has a longer useful life.

Fourth, capitalization requires a service contract to be paid up-front so that the costs can be amortized over time. This type of accounting limits the options that are available to the utility. Services that are available only short-term or only through yearly service contracts are not compatible with this approach. As an alternative, some approaches below allow for services to be treated as short-term expenses.

Finally, like capital investments, the utility might have the incentive to pay inflated costs for the pre-paid contract in order to increase its rate base and earnings.

5. NON-WIRES ALTERNATIVE SHARED SAVINGS ("NWA OPTION")

On January 25, 2017, the NY PSC issued an *Order Approving Shareholder Incentives*[30] concerning a proposed NWA shareholder incentive for Consolidated Edison (Con Edison), the utility serving New York City. The Order provides for a shareholder incentive that is based on a 30% share of the difference between the net present benefits of the NWA and the traditional solution that it replaces in

[29] Conference Report on H.R. 1. House Report 115-466. P. 353. Dec. 15, 2017. Congress Session 115-1.

[30] See Case 15-E-0229 Petition of Consolidated Edison Company of New York, Inc. for Implementation of Projects and Programs That Support Reforming the Energy Vision.

order to encourage the utility to pursue more cost-effective solutions. The net benefits of each project are determined by New York's Benefit Cost Analysis (BCA) framework that includes societal benefits, such as carbon reductions, in addition to energy and capacity benefits. If a utility chooses to defer or avoid a distribution upgrade through NWAs, the utility can recover the costs of the NWA, including the cost of service payments from the utility to customer and third-party owned resources, over 10 years and collect its carrying costs over that time. The utility would record the NWA costs as a regulatory asset as previously described. The shareholder earnings incentive is added on top of the capitalized regulatory asset. And as an added incentive, cost overruns and underruns are shared 50/50 between Con Edison and its customers, which effectively decrease or increase the company's incentive. If the utility reduces costs significantly, it can share in the savings up until the total incentive reaches 50% of the net present benefits of an NWA. On the flip side, if there are cost overruns in implementing the NWA, the incentive can shrink all the way to $0. We did not model this feature as it relies on differences between projected vs. actual implementation expenses.

For other states that want a simpler process or narrower range of benefits considered, the total cost of the NWA and projected cost of the avoided capital expenditures (including carrying costs) could be compared, and the incentive could be set as a share of the difference. For the purpose of our model, we used this simplified approach, and so therefore our calculation of the incentive differs from and is not reflective of how it is implemented in New York.

The major benefit of the NWA is that it provides for the deferral of a larger capital project, which can save the utility and its customers money, while providing the utility an earnings opportunity for NWA solutions. The NWA Option relies on a prepaid multi-year service expense that would be amortized over time as a regulatory asset with the utility return applied to the yearly unamortized balance. This is identical to the Prepaid Contract Option. But the NWA approach goes further and provides an incentive based on cost effectiveness. Additionally, setting an incentive based on shared savings encourages reductions in costs in order to maximize benefits to customers. As the net benefits to customers grow, so does the reward to the utility for creating these efficiencies.

Like pre-paid contracts, among the advantages of the NWA approach is that these transfer the operating and construction risks to the third party. In addition, unlike the Reference Case, a prepaid contract would likely have minimal additional indirect costs. This approach also incentivizes utilities to pursue less expense options by sharing the cost savings, which helps to offset the loss of earnings on a smaller rate base.

While this mechanism provides a number of good efficiency signals to utilities, it is more complex, which creates administrative burdens. The NWA and avoided investment must both undergo a BCA which is a granular exercise subject to numerous assumptions. As discussed above, this could be simplified by merely comparing total costs of the NWA solution vs. the traditional solution. This is how we have modeled the mechanism, but it still requires developing long-term cost projections. This mechanism also presents the potential for gaming if the utility attempts to inflate the costs of a traditional investment in order to increase the calculated savings and net benefits of the NWA solution. While this type of problem is not new for commissions who regularly scrutinize utility capital plans, it may argue for additional care in the review of an investment that is used as a benchmark for a shared savings mechanism. Additionally, as this solution relies on the capitalization and amortization of an expense, another issue is that it must be prepaid rather than paid out over time like most payments for services.[31]

6. MODIFIED CLAWBACK MECHANISM

Prior to implementing the NWA incentive, the NY PSC had modified its net capital plant reconciliation mechanism ("clawback" mechanism) to compensate for lost earnings related to NWA projects, but through a different way. If a utility is looking to boost short-term earnings, a utility can underspend relative to its planned capital budget upon which rates are based. When it does so, the utility is able to retain the savings as earnings until its next rate plan period. (A utility that chooses this option would sacrifice greater long-term earnings on capital investments that were never made.) To compensate for this short-term incentive to underspend, the clawback mechanism returns the unspent capital budget and associated earnings to customers.

During the course of the Reforming the Energy Vision Proceeding, the NY PSC ordered changes over the concern that there was the potential for the clawback mechanism to interfere with the goal of encouraging utilities to rely on DER for NWA projects that replace utility capital expenditures. If the utility were to replace a capital expenditure with a DER contract, the clawback mechanism, as currently structured, would reduce utility revenue and earnings by returning the unspent capital and earnings associated with the avoided capital investment to ratepayers. Simultaneously, the cost of the service payments would increase the utility's operating expenses beyond what was included in rates.

The modification the NY PSC ordered to the clawback mechanism is relatively simple and can be implemented within existing rate plans. It also has a number of ramifications. The order states that if the utility shows that a portion of its capital budget was avoided by a service expense for DER, the clawback mechanism will not be implemented on that portion of the budget. The utility will retain the avoided portion of the capital budget and associated earnings and will pay out the service expense without additional rate recovery. Thus, as long as the yearly service expense is less than the

[31] Prior to recent federal tax reforms, bonus depreciation applied to utility capital projects installed before 2019. Deferrals of large capital projects had the impact of increasing the cost of capital projects beyond 2019, due to the loss of bonus depreciation. Under the new law, utility property in service after Sept. 27, 2017, is exempt from bonus depreciation. See Conference Report on H.R. 1. (Footnote 29).

yearly amount of depreciation and carrying costs in the capital budget, the utility will profit by retaining the savings. At the next rate case, the elements of the revenue requirements associated with the avoided capital are removed and the cost of the service contract is added to O&M expenses.

There are a number of positive traits about this modified mechanism. First, it allows the utility to maintain its earnings as if it actually invested the capital; at least for the duration of its rate plan. It can also share in the savings from using a less expensive service expenditure. Until the next rate case, the utility actually captures all of the savings as earnings, and then in years subsequent to the rate case, the customers receive all of the savings since the capital budget has been reduced and the service expense continues to be paid through the O&M budget. Also, as the savings are generated through a comparison of yearly costs, the service expenditure can be paid out on a yearly basis and does not need to be prepaid. And, so long as the yearly expense payments are lower than the cost of the capital investment, customers benefit once rates have been reset in a new rate case. Finally, this approach is relatively less burdensome to implement.

The primary disadvantage of the modified clawback mechanism is that it is only effective for a short time -- for the period of the rate plan. In New York, utilities typically file a rate case every three years. After the next rate case, the utility's operating expense budget will increase to include the cost of the DER expense, and the utility will no longer retain the savings from the avoided capital investment unless the capex is simply deferred. In a deferral event, the utility would spend the capex once the deferral ends and typical earnings would resume. While this covers the ongoing cost of the DER expense so the utility does not have to absorb it, it may not leave the utility neutral during the years following the initial rate case as the capital investment may still be deferred over the life of the DER expense. Only during the rate plan in which the initial capital investment was avoided does the utility effectively earn on the DER expense.

As with other options, the modified clawback shares certain drawbacks. Similar to the NWA option, the utility receives additional earnings based on the difference in cost between the avoided capital investment and the non-wires alternative. The higher the estimated cost of the avoided capital investment, the higher the savings (and earnings) when a non-wires alternative is used. Therefore, regulators will need to make sure that an appropriate estimate of costs is used for the avoided capital investment.

If the utility retains the savings only until the next rate case, then the maximum amount of time a utility can earn on the savings can be fairly short (no more than three years in the case of New York). This may be sufficient for an asset that lasts 5-10 years, but it is likely to fall well short of providing the earnings expected from a 30-year investment. The timing of the investment can also be a constraint. If the investment happens early within the rate plan, then the utility can earn for up to 3 years, but if the utility has planned to make the investment shortly before the rate plan ends, then it may not be able to retain any savings as earnings.

Nevertheless, as one of several modifications to earnings that regulators can implement, the modified clawback mechanism can help to incentivize utilities to pursue cost-effective service options, and may make the most sense when combined with other options.

7. PAY-AS-YOU-GO REGULATORY ASSET (PAYGO)

Reviewing the various options previously presented inspired us to devise an additional mechanism that attempts to overcome some of the limitations with them. We developed a new option which combines the use of a regulatory asset and delayed amortization. As a utility spends money on a DER solution, they build up a regulatory asset that they amortize over a term that may extend beyond the life of the contract. This approach could allow for both a pre-paid and an annual contract, depending on the pace of amortization that is used. The utility earns their approved rate of return on the regulatory asset, similar to the Prepaid Option.

As an example, assume a utility is paying for yearly service expenditure in the amount of $100,000 per year over six years. Every year, it pre-pays the $100,000 to the provider and places that amount in the rate base as a regulatory asset. Commissions have broad discretion to determine the length of amortization over a regulatory asset, and for the purpose of this example, assume the Commission has allowed the utility to amortize the asset at a rate determined by the amortization period. This 3-year term equates to amortization of 1/3 of the gross asset in the first year, which sets the rate of amortization for subsequent years. The amortization of the regulatory asset would work similar to how group depreciated assets are depreciated. Each year that the utility spends $100,000 on the service, the gross amount of the regulatory asset would grow by $100,000. Each year, one third of the gross regulatory asset is amortized. Thus, the amortization amounts would increase over time until the remaining amortization base would be maxed out, at which time the amortization would equal the contract expense as shown in Table 1.

Table 1: Example Amortization of PayGo Option

Accounting Item	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Contract Expense	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
Regulatory Asset - Gross	$100,000	$200,000	$300,000	$400,000	$500,000	$600,000
Amortization	$33,333	$66,667	$100,000	$133,333	$166,667	$100,000
Accumulated Amortization	$33,333	$100,000	$200,000	$333,333	$500,000	$600,000

Using this method, there are two ways to charge the customer for the $100,000 service expenditure. The first option would be to have the amortization expense flow through to the income statement. Using this option, the total cost to the customer is the same in terms of nominal dollars, however, it is lower in terms of real dollars since the cost to the customer (amortization expense) is deferred to later years. If a customer is a customer of this utility for the entire length of the contract, this is a better option. However, if a customer becomes a customer of the utility in years 3 or 4, they are paying more than the $100,000 ($133,333 and $166,667 in the example) but are receiving the same service. To better match the service expenses and charge the customers as the service is consumed, the second option charges the customer the full-service expenditure by flowing through the expense to the income statement through O&M. When using this option, the regulatory asset is still built up over time and amortized the same way, however, the amortization expense does not flow through to the income statement. The sole purpose of tracking the regulatory asset is to determine a rate base amount, so the utility can generate earnings on this rate base.

Our PayGo option also contains a scaling incentive that is proportional to the savings the utility provides to the customer, up to a 50% cap. For instance, if the utility is able to find a $700,000 service to replace a $1 million traditional investment (30% savings), the utility would get 30% of the difference, or $90,000 in this case. This $90,000 is then spread into equal payments for each year of the avoidance or deferral of the traditional solution. The incentive is capped at 50% because customer savings decrease in dollar terms beyond that point.

The main drawback of this option is its complexity. While it fits within existing accounting rules, utility accounting systems may not be set up to amortize regulatory assets in this fashion. Also, depending on the length of the contract and the amortization period, there could be costs following the end of the provision of the service, which some may view as a problem of temporal equity.[32] Additionally, the scaling incentive based on cost savings may increase the need for regulatory scrutiny of the avoided solution so that the incentive is not artificially increased through inflating the costs of the avoided solution.

The primary benefit of this service-based solution is that it provides traditional rate base earnings *and* allows for more flexible periodic payments. The periodic payments means it can be used for longer-term contracts for which full prepayments are not suitable. The amortization period can also be adjusted to more easily hit cost/earnings targets. In our model, setting the amortization to one-third the length of the avoidance or deferral period approximated cost and earnings closest to the investment of a similar amount placed into the rate base in the traditional way. And last, our scaling incentive means that additional utility earnings are kept small if the cost savings is small and grow as the

[32] Some may take issue that some customers may be paying for a service or benefit that they are no longer receiving, even if it is a more cost effective way of providing for the benefit overall. A similar analogy exists to utility rates generally, which are primarily retrospective and pay for past utility investments. Some customers may be paying for system additions or upgrades that were once useful based on the usage of previous customers, but are no longer useful because usage patterns of existing customers have changed.

cost savings grow. This increases the incentive to provide cost savings over a straight-line percentage (such as 30%).

8. UK TOTAL EXPENDITURE ACCOUNTING (TOTEX)

In preparing this paper, we also examined an international example for a regulatory approach but given the questions about compatibility that we describe later, we chose not to model it. The topic of capital bias has been taken up by regulators in the United Kingdom (UK) where particular focus has been placed on this issue. In the UK a novel PBR variant called RIIO (Revenue = Incentives + Innovation + Outputs) is employed by energy regulators for regulated electric and gas transmission and distribution utilities.[33] Among the innovations in the RIIO structure is the concept of total expenditures, or "totex", to address the treatment of capital (capex) and operating expenses (opex). The totex approach is an accounting strategy under which capital and operating expenditures are treated as equivalent and recovered under a formula that treats all expenditures the same. It is thought that this, in combination with a revenue cap mechanism with shared costs and savings, provides powerful incentives to reduce total costs, and since the distinction between whether costs are capitalized or expensed is eliminated, the bias toward capital expenditures would be reduced.

Under traditional ratemaking operating expenses and capital expenditures are treated differently. Operating expenses are recovered in one year while capital expenditures are recovered over many years, with the balance of unrecovered capital investment placed in rate base. Variations in operating expenses affect utility income to a greater extent, thus the utility's focus is logically on managing (lowering) operating expenses. As a natural extension, when choices exist between capital and expense solutions, utilities would be inclined to choose capital solutions. Under the totex approach, capital and operating expenditures are treated as equivalent. At the end of the year, total actual expenditures are compared to the total rate allowances, i.e., the allowed revenue generated from rates. The variance in totex (positive or negative) is then shared between customers and the utility using a sharing factor. Currently UK electric distribution network operators (DNOs) retain between ~54%-70% of the totex cost variances. The remaining variance is then used to adjust the upcoming rate allowances for the regulatory asset value (RAV or rate base) and opex (the totex adjustment to rates) based on a formula. It is important to note that the totex adjustment only reflects about one-half the cost variance in rates. In other words, only a portion of the variance in costs loses the distinction between capital and expense. One might argue that this approach reduces but does not

[33] The RIIO model also employs some other powerful PBR features, including an extended (8 year) price control period, targeted financial incentives (potentially enabling each utility to earn roughly a 2-10.5% range in return on equity), innovation provisions, and the requirement of very detailed business plans addressing key areas of utility operations.

completely eliminate the distinction between capital and expense.

The totex formula sets a ratio of "slow money" (capex) to "fast money" (opex) which is called the capitalization rate. Slow money is depreciated over 20-45 years and is added to the regulatory asset value (RAV or rate base) which earns the cost of capital. Fast money is recovered on an annual basis. The ratio of slow money to fast (capitalization rate) ranges between 62-80% of total expenditures. This rate is applied to the totex adjustment after the utility incentive is deducted regardless of the actual ratio of capital and operating expenditures. In other words under totex, adjustments to the RAV do not necessarily reflect actual capital expenditures; rather they reflect the slow portion of the totex adjustment. Conversely, costs charged to expense in a year may not reflect actual operating expenses, rather they reflect the fast portion of totex adjustment (or 1 - capitalization rate).

There have been some recent assessments performed on the RIIO approach, including totex performance. According to the UK utility regulator, the Office of Gas and Electricity Markets (Ofgem):

> We are only half-way through the existing set of price controls for gas and electricity transmission and gas distribution, and we have only analysed one year of data for electricity distribution. Nevertheless, our current assessment of the experience of RIIO-1 is as follows:
>
> - Outputs: For gas distribution, electricity distribution and gas transmission network companies we currently expect outputs to be fully delivered by the end of the price control periods.
> - Expenditure: After the first year of the RIIO-1 electricity distribution price control, network operators are now forecast to spend 3% less than their allowances over the course of the price control.
> - Financial Returns: Like other regulators, we measure the financial performance of network companies using the return on regulatory equity (RoRE) measure. When we set RIIO-1, the intention was that the best performing companies (in terms of delivering output targets and efficiency against totex allowances) could achieve low double digit RoRE returns. In practice, the majority of network companies are delivering strong earnings towards the top end of our expectations for each sector.[34]

Ofgem also noted that "RIIO-1 has brought benefits to consumers. "We estimate that the average domestic consumer will pay less for the gas and electricity distribution network in 2017-18 compared to 2016-17 … In summary, there are many positive aspects to RIIO, such as a stronger focus on delivering outputs for consumers, supporting innovation, and incentives to encourage companies to plan for the long term."[35]

[34] Ofgem Open letter on the RIIO-2 Framework, dated July 12, 2017

[35] Ofgem also noted that "RIIO is a complex price control system, with many interlocking incentive

Ofgem reported recently that "In the first year of RIIO-ED1, DNOs collectively spent £3.2bn [$4.2 billion] managing their network; 9% less than the allowance set at the price control for that year…As the price control progresses we will better understand what is driving the totex underspend: for example, savings through efficiencies and innovation or non-delivery of work. It is too early to draw conclusions but when we do this will inform our assessment for RIIO-ED2."[36]

The New York Commission also provided a high-level assessment of the totex incentive. It stated:[37]

> Mechanisms that consider efficiency of total expenditures like the totex approach have the potential to eliminate any capital bias that may undermine the economic substitution of DER resources for traditional utility capital expenditures…Equal rate treatment of opex and capex would facilitate these efforts...Staff has identified technical obstacles to adopting a full totex approach at this time. In addition, parties have identified concerns over how and why totex would be an improvement over current approaches. Totex should continue to be studied, including both the efficacy of totex in addressing utility behavior, and potential means of dealing with accounting standards…As the United Kingdom gains more experience with RIIO, Staff and parties should evaluate that experience, explore alternatives, and report on their findings in the context of a rate case proposal or a DER program filing.

Several observations are apparent with the totex approach. Under totex if a utility significantly increases spending on capex above what the capitalization ratio predicts, it would in effect expense (rather than capitalize) a portion of that capital expenditure. This could create adverse tax differences since the tax rules require capital assets be depreciated over their tax lives rather than be immediately written off.

Conversely if the utility spends more on opex than predicted, it would capitalize a portion of the opex or in effect create new regulatory assets. As noted in the utility accounting section, recording of regulatory assets is a normal aspect of utility accounting and is accommodated under GAAP. The tension comes when regulatory assets become so large in proportion to the company's capitalization. Generally, in the United States, utility physical assets can receive financing without difficulty, but it is not clear whether substantial amounts of paper (regulatory) assets would adversely impact a utility's cost of capital or ability to raise capital.

mechanisms and a significant regulatory burden in terms of information production and reporting. We would like to take this opportunity to explore if it could be simplified and focused more on areas that are most valuable to consumers."

[36] RIIO-ED1 Annual Report dated February 24, 2017, pages 1-2.

[37] Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, Issued and Effective: May 19, 2016, pages 103-104.

In New York, the Staff White Paper noted that:

> Adopting the totex approach in New York would face significant obstacles, given differences in accounting standards between the United States and the UK. Moreover, even if rates were based on regulatory totex values, public financial statements would still be presented in conformance with traditional accounting standards, and utilities and financial managers would [likely] be held accountable on that basis, reintroducing the distinction between capital and operating expenses… In 2014, utility assets in New York included over $4 billion of regulatory assets, or 24% of utility equity. Adoption of an alternate approach such as totex could expose utilities to a write-off of these regulatory assets, since a totex approach will hinder a utility's ability to demonstrate that specific recovery of these assets is being provided through rates [a requirement to recording regulatory assets under GAAP]. Deferrals are not permitted under the UK system, and an inability to book deferrals would inhibit approaches under REV that would require utilities to defer and earn a return on certain DER-related operating expenses. It could also increase earnings volatility and increase the cost of capital.

We believe, as New York does, that the totex approach holds promise for mitigating the utility's bias towards capital expenditures. However, as even the UK regulator notes, more study is required; especially the incentive effects and accounting and financial implications of how totex would operate in the U.S. system.

MODELING AND ANALYSIS

Technology-Specific Considerations

While this paper has generally taken a technology-neutral approach in addressing service-based solutions, there are some meaningful differences between types of services that can have an impact on which option works best. These differences include the lifespan of the technology, the lifespan of a comparable utility solution, technology-specific tax implications, and whether the service defers, augments, or entirely replaces a traditional utility solution. Due to these differences, we have created two categories of service-based solutions: cloud-based computing and non-wires alternatives. We have limited the categories to two for simplicity, and they may not capture all of the relevant differences.

In the case of cloud computing, these service contracts often run for around five years and replace or augment on-site software and IT that would be amortized over five years. Situations where cloud computing defers rather than replaces an expected IT investment need are possible, but are far less common. Software deployed by a utility has access to somewhat accelerated tax depreciation, for which a cloud computing solution funded through a regulatory asset is ineligible.

NWAs on the other hand can be for a variety of contract lengths. Sometimes they are based on the lifespan of the asset from which the utility is purchasing services, which can be for 20 years or longer. In other instances, the utility may be purchasing demand response, and those contract lengths can vary greatly. The assets that these NWAs are deferring or replacing, however, typically have much longer useful lives: 40 years or longer for transformers, depending on the loading of the system. This creates a much larger discrepancy between the length of the service contract and the lifespan of the avoided asset than in the case of cloud computing. Also, NWAs sometimes delay or defer a utility investment need rather than fully replace it. That deferral has value because the cost of service can be lowered during the deferral period if the service solution is more cost effective than the traditional utility solution over the time period that it is deferred. Our model, as we describe below, captures the value provided both from NWA temporary deferrals and long-term replacements of traditional "wires" solutions. Tax implications for NWAs are similar to cloud computing solutions, since NWAs usually replace physical capital assets that are eligible for accelerated depreciation.

Our Approach to Modeling

To better understand the impacts of the regulatory options, we created a detailed financial model of a typical distribution utility that allows us to project the financial impact on utilities, customers, and third-party providers. In order to capture the key variances between the two technology types described above, we modeled each of the six regulatory approaches (the five new options plus the Reference Case and Service as O&M representing standard practice) for three deployment Scenarios along with two different Cost Cases for each.

Deployment Scenarios

Short-Term Replacement – This scenario is meant to depict the typical deployment of a cloud computing service solution. In this case, a service contract of five years completely replaces a utility solution that is also expected to last five years. The model only computes the earnings and costs for five years, but the scenario could be repeated again after the fifth year to get a longer projection of the financial impact.

Short-Term Deferral – This scenario is meant to show the impact of an NWA that defers the need for the utility to invest in a traditional distribution solution by five years. In year six, a utility capital investment is made that is amortized over 40 years. The model provides a detailed breakdown of the costs to customers, the earnings for the utility, and the payments to third-parties (if applicable) for the first 42 years,[38] then provides a terminal value to project the remaining years 43-47.

Long-Term Replacement – This scenario is meant to show the impact of a service that replaces the need for a capital investment over a period of 40 years. In this scenario, the utility capital investment is never made. This is meant to estimate the financial impact of these mechanisms over the long term if the service is able to completely replace the need for a traditional utility investment.

Making an Accurate Comparison

Given all of the variables at play, even in the same deployment scenarios, it became clear that there was no such thing as an "apples-to-apples" comparison, making the task of evaluating the merits of each mechanism a more complex task. We initially attempted to align each mechanism at the same NPV cost to customers (with utility earnings and direct investment in capital or service solutions being the most relevant variable outputs). However, this approach masked the impact of each mechanism on customer costs for similar investments amounts, a key interest for regulators. Instead, we have tried to level-set each solution at an NPV equivalent of $1 million of utility capital investment. This capital investment, consistent with standard accounting practice, is assumed to come into service in the middle of the first year, with part of the capital investment entering the rate base in rate year 1 and the remainder entering the rate base in rate year 2. Because of this time disparity, the cost of that utility investment in present value terms is $968,100.[39]

While fixing the investment amount to the equivalent of a $1 million capital expenditure is

[38] Even though the asset is amortized over 40 years, the model extends to 42 years to capture the impacts of timing of the in-service date for capital investments and some costs that are recovered in rates the year after they are incurred.

[39] We have given similar treatment to the service solutions in the interest of comparability. The speed of implementation for service solutions may be much shorter or potentially longer, depending on the type of solution and customization required.

intended to provide an equivalent comparison point, to an extent it hides other factors that make a direct comparison difficult. When the total cost to customers is calculated for the $1 million utility investment in a traditional asset, other necessary costs are added, such as property taxes, utility earnings, income taxes, and O&M costs for servicing the asset. All of those costs are calculated separately from the cost of the asset itself. For a service expenditure, the provider of the service will also have to pay taxes, pay O&M costs, and recoup earnings from the service fee in addition to funding any assets to provide the service. These private costs are unknown and can vary greatly from utility costs. When a utility uses a service instead of a traditional asset, there may also be O&M costs relating to the integration of the service, but this is highly situation-dependent and we did not include it in our modeling. For these reasons, we have set the amount invested in a capital asset and the cost of a service solution equal to each other to try to create as level of a comparison as possible. However, readers should keep in mind that this falls short of actually creating a level comparison, as the costs imbedded in the utility solution and the service solution are not completely comparable.

Additionally, the model makes an implicit assumption that the outputs from the service options are equal to what the utility provides from its own investment. In reality, while the service would need to meet the same core needs that the utility investment would fulfill in order to offset the utility-owned asset, the outputs from the service could be very different. For example, while both onsite and cloud-based billing systems might fulfill the same core billing needs, the cloud-based system might be able to easily provide extra customer engagement options that the onsite system could not. Similarly, in an NWA context, a utility transformer and a customer-owned DER might be able to provide for the same capacity need, but the DER might also provide carbon reductions, resilience, and other benefits while also introducing new problems such as operational duration (e.g., a four-hour discharge limit on a battery). While important for decision-making, we made no attempt to evaluate these other costs and benefits of potential solutions.

Key Financial Assumptions

Return on Equity (RoE) and Capital Structure – Our modeled utility is representative of an "average" utility. We used the average return on equity currently in effect at utilities, 10.13%,[40] and a capital structure of 55.4% long-term debt, 43.1% equity and 1.5% short-term debt.[41]

Weighted Average Cost of Capital (WACC) – As discussed earlier in this paper, there is a necessary spread between the cost of equity and allowed return on equity. A business must be able to provide economic returns over the long-run for it to be attractive to shareholders. For the purpose of calculating the revenue

[40] AEE Powersuite Database, Average Allowed RoE of major IOUs in effect as of October 2017, https://powersuite.aee.net/portal

[41] Edison Electric Institute (EEI) 2016 Financial Review, page 11 for equity and debt ratios.

requirement to fund our modeled utility, we used the RoE above. This represents the RoE that the utility is allowed to collect through rates to fund its investments. However, for the purpose of determining the WACC, we used a 7% cost of equity to reflect the required return of shareholders. This better represents their opportunity costs and their time-value of money for calculating cash flows over the long run. The capital structure mentioned above was used with a cost of long-term debt of 5% and a cost of short-term debt of 1%. Using these inputs, the pre-tax WACC used in the model was 6.80%.

Prepaid contract yearly discount rate – In order to accurately reflect the time-value of money associated with a pre-payment of a multi-year contract, we have created a discount rate for prepaid contracts that is separate from the utility's pre-tax WACC. A private, unregulated company will usually have higher costs of capital and would likely be unable to provide a discount at the utility's full WACC. A yearly discount in the range of 3-5% is more likely. That said, discounting the upfront contract prepayments with a lower rate while not simultaneously escalating the yearly service payments over time by a growth factor would significantly distort the value of the pre-paid options relative to the periodic payment options. Our model does not include an escalator for service payments over time, and projecting how technology, efficiency gains, or other factors might change the cost of a service in the long-term is too much of an unknown. Therefore, we chose to leave the WACC and the pre-paid contract discount the same to level-set the pre-paid and periodic payment options. In doing so, both the pre-paid options and yearly payment options have the same net present value.

Taxes – The model includes Federal income taxes at a rate of 21%, state income taxes at a rate of 5%, and state property taxes at a rate of 1.5%. Actual state income and property taxes will vary by state.

Calculating Project NPV – The project NPV is a calculation of value that puts earnings in perspective relative to the costs associated with generating those earnings. Typically, a company's WACC is used to discount future cash flows in an NPV calculation, and this is the method that we used in our model. However, there is an argument to be made for using the cost of equity alone in determining the value of a project to a shareholder of a regulated utility. For a typical business, an investor receives the benefits of capital provided through cheaper debt. Lower-cost debt allows a company to leverage investor equity and make it go further than funding through equity alone. Utilities also leverage debt, but the benefit of the lower cost of debt is retained by customers and does not provide a direct financial benefit to shareholders. Therefore, the cost of equity could be used when looking at the value of earnings from a shareholder perspective. We did not separately calculate a project NPV using the cost of equity given the small difference between the WACC and cost of equity in our model.

Impact of Changes to U.S. Tax Law

On December 22, 2017, President Trump signed Public Law 115-97 (unofficially the "Tax

Cut and Jobs Act of 2017"), introducing several important changes that impacted the results of our modeling. We have incorporated the new tax law into our modeling to the best of our understanding. The two most significant changes were the lowering of the corporate tax rate from 35% to 21% and the elimination of bonus depreciation for utility investments starting September 2017.[42]

The impact of the lower corporate tax rate is straight forward. As taxes are a pass through to customers, rate payers will directly benefit from lower taxes on earnings. Utility earnings are unaffected, so utilities are neutral to this change. The impact of the elimination of bonus depreciation is more complex. Bonus depreciation has the impact of lowering taxes,[43] which decreases the size of the rate base, lowering utility earnings. The loss of bonus depreciation means that new utility investments, all other things held constant, will increase costs to customers and will generate higher earnings for utilities. Under the former tax law, bonus depreciation was scheduled to sunset in 2019. The new tax law expanded bonus depreciation for most businesses, but exempted utility investments made after September 2017.

The net result of our modeling, taking into account both the 21% corporate tax rate and the elimination of bonus depreciation, is that new utility investments both will result in higher costs to customers and higher earnings for utilities relative to the former tax law.[44] However, companies providing service solutions will benefit from the expanded 100% bonus depreciation in the tax law, decreasing their tax costs. Thus, we conclude that the new tax law has placed service providers in a more advantageous position relative to utilities, which may increase the competitiveness of service solutions relative to utility capital investments as a result.

[42] Conference Report on H.R. 1. House Report 115-466. P. 353. Dec. 15, 2017. Congress Session 115-1.

[43] Under tax normalization requirements, tax benefits from accelerated and bonus tax depreciation are deferred and credited to customers over the life of the asset rather than being passed on to customers immediately.

[44] The loss of bonus depreciation does not mean that electric rates will increase as a result. Utility rate base consists of the undepreciated balance of past investments, and changes to bonus depreciation will only impact future investments made after September 2017. The reduction in the tax rate will mean earnings from the current rate base will be taxed at a lower rate, decreasing costs to customers.

MODELING RESULTS

When analyzing the results from the model, there were three key outputs that we looked at:

1. NPV cost to the customer
2. NPV of utility earnings
3. Project NPV

The cost to the customer entails all costs the customers will be required to pay through rates in order for the utility to generate their approved return. The utility earnings are a combination of the traditional earnings through a return on rate base as well as a return from the various implemented mechanisms which include a markup on O&M and a cost savings sharing mechanism, when they are applicable. Lastly, the project NPV encompasses all cash inflows and outflows related to the project. As previously mentioned, all cash inflows and outflows (including the cash in these metrics) were discounted to their present value by the WACC to generate an NPV. The project NPV is the best measure of total value to shareholders as it represents any earnings in excess of the cost of equity, i.e., their required return.

Scenario 1: Short-Term Replacement of a Utility Software Investment

As explained earlier, this scenario best represents a typical cloud service deployment, where a short-term service replaces the need for a similarly short-lived utility investment in software. The length of the service contract and the life of the avoided utility investment in software are assumed to line up: five years in each case. The results for all business model option are provided in Table 2. Additionally, Figures D and E provide a graphical comparison of customer costs and project NPVs across the options.

Table 2: Modeling Results for the Short-Term Replacement Scenario

Short Term Replacement of 5 Year Utility Software Investment			
Statistics	**Option**	**Equivalent Cost Case**	**Lower Cost Case**
NPV Cost to Customer	Reference Case	$ 1,140,435	$ 1,140,435
	Service as O&M only	$ 993,453	$ 745,090
	DER Adder	$ 1,032,179	$ 774,134
	Capitalization of Pre-Paid Contract	$ 1,027,448	$ 770,586
	NWA Shared Savings	$ 1,054,500	$ 859,137
	Modified Clawback	$ 1,104,921	$ 991,342
	PayGo	$ 1,037,090	$ 866,615
NPV Utility Earnings (Accounting Earnings)	Reference Case	$ 87,854	$ 87,854
	Service as O&M only	$ 5,284	$ 3,963
	DER Adder	$ 34,347	$ 25,760
	Capitalization of Pre-Paid Contract	$ 94,810	$ 71,107
	NWA Shared Savings	$ 115,112	$ 137,564
	Modified Clawback	$ 88,940	$ 188,775
	PayGo	$ 37,641	$ 94,873
Project NPV (Shareholder Value)	Reference Case	$ 28,476	$ 28,476
	Service as O&M only	$ 2,222	$ 1,667
	DER Adder	$ 31,286	$ 23,464
	Capitalization of Pre-Paid Contract	$ 31,105	$ 23,329
	NWA Shared Savings	$ 51,408	$ 89,786
	Modified Clawback	$ 85,879	$ 186,479
	PayGo	$ 34,580	$ 92,577
	NPV 3rd Party Payments	$ 968,141	$ 726,105
	Yearly Service Payments (5 years)	$ 242,618	$ 181,964
	Pre-Paid Contract Payment	$ 1,034,022	$ 775,517
	Pre-paid Amortization years	5	5
	PayGo Amortization Years	1.67	1.67

The key results of this scenario are as follows:[45]

Reference Case – A utility investment of $1 million (NPV equivalent is $968,100) would cost customers an NPV $1.14 million over the 5-year life of the asset and generate NPV earnings of just under $87,900. Discounting all cash inflows and outflows at the WACC yields a project NPV of almost $28,500, the most relevant measure of value for shareholders.

Service as O&M – Under standard practice, if the utility were to replace its $1 million capital investment with a service expenditure of $242,600 per year for 5 years, the total NPV cost to customers would be $993,500 saving customers approximately $147,000 over the Reference Case. However, the utility earnings, which are only generated from the return on working capital, decrease dramatically from $87,900 in the Reference Case to $5,300 with the service option. In other words, the utility

[45] Note that dollar figures in the text have been rounded to the nearest hundred dollars.

experiences a $82,600 opportunity cost when it chooses the service option without any changes in regulatory treatment. The project NPV decreases from $28,500 to $2,200, a 92% drop in value to shareholders.

DER Adder – This option results in the cost savings to customers compared to the reference case. It also provides a relatively low amount of total utility earnings (only 39% of the Reference Case). However, these earnings must be viewed from the context that the utility never paid any money up front (it came from its O&M budget), and so shareholders bore no risk and no capital had to be returned to them through amortization. As such, these earnings are relatively more valuable than the low gross amount would indicate. This is reflected in the project NPV, which is $31,300, which is slightly higher than the project NPV of the Reference Case. However, this project value decreases commensurate with the reductions in the service costs in the Lower Cost Case. Those cost savings reduce the project NPV, or shareholder value, to $23,500, or about 82% of Reference Case project NPV.

Capitalization of a pre-paid contract ("Prepaid Option") – The prepayment of the yearly service payments for five years (including the 6.80% discount per year described above in the assumptions) results in a lower cost to customers (NPV $1.03 million) than the Reference Case, but also higher earnings in the amount of $94,800 for the utility. The main reason that the Reference Case has higher costs to customers is that we set service costs and capital investments equal to each other as an assumption in our model. As described earlier, there are several costs (e.g., taxes and O&M) that are imbedded within the service fees that are not included in the utility capital investment and are instead calculated separately and factored into the total cost of the Reference Case. Another difference is that the utility software investment receives accelerated depreciation, while the cloud computing investment funded through a prepayment does not. This decreases the cost of taxes for the Reference Case and has the added impact of shrinking the rate base slightly through accelerated depreciation, thereby decreasing earnings. Thus, the model shows that the prepaid option is both relatively cheaper and provides marginally greater earnings for the utility. In project NPV terms, the value to the utility is even closer to the Reference Case at $31,100 (vs $28,500 in the Reference Case). In the case of a prepaid service contract that is 25% cheaper, the model shows a 25% reduction in the total cost of the option as well as the earnings and project NPV metrics. This makes sense as the earnings that the utility receives from the prepaid option are proportional to the costs.

NWA with Shared Savings – This option functions the same as the Prepaid Option, except for the addition of a shared savings mechanism that provides the utility 30% of the total cost savings compared to the Reference Case. As the Prepaid Option is $113,000 cheaper than the Reference Case in NPV terms, the NWA Option receives an after-tax incentive of $20,300 that is spread evenly across the 5 years. Since the incentive does not escalate over time, this lowers the additional NPV cost of the incentive (as well as the NPV boost it provides to utility earnings). However, the total earnings are meaningfully higher than the

Prepaid Option ($115,000 vs $94,800), and that spread increases substantially when the service option is 25% cheaper ($137,600 vs $71,100). However, in project NPV terms, the NWA option becomes substantially more valuable than the pre-paid option ($51,400 vs $31,100), as a higher percentage of the NWA Option earnings come from incentives, which do not have any equity cost associated with them as opposed to regulatory asset-based earnings which do.

Modified Clawback Mechanism – This option is the second most expensive to customers ($1.10 million) behind the Reference Case. The earnings for modified clawback in the Equivalent Cost Case ($88,900) are higher than the Reference Case, and in project NPV terms, this option returns the highest value ($85,900) as the expenses for this option are entirely funded from O&M and therefore required no shareholder equity.[46] In the Lower Cost Case, the modified clawback is still the second most expensive option, but the earnings jump significantly. This is because all savings resulting from the decreased cost of the service solution are retained by the utility for three years (until the next rate case). It is only in the fourth and fifth years that customers realize any cost savings. In project NPV term, the value of the project to the utility ($186,500) is significantly higher than the second most profitable option in project NPV terms -- the PayGo Option at $92,600. In this Scenario, with the Lower Cost Case assumptions, this results in high compensation to the utility because it retains the majority of the savings over the five years. However, this assumes that the savings start at the beginning of a rate plan period. If rates are reset in a shorter period of time, more savings will accrue to customers, and the benefit to utility shareholders will be greatly reduced. Assuming a new program can take a year or more to implement, and assuming this would not begin until after the rate case is concluded, with a three-year cycle of rate case submissions, the benefit will likely be less than three years.

PayGo – This option compares well to the Reference Case in terms of cost to customers in both of the cost cases. Utility earnings are lower for this option than the Reference Case, though the project NPV is higher. The strong shared savings mechanism provides a significant boost to project NPV in the Lower Cost Case. The project NPV rises from $34,600 to $92,600 in the Lower Cost Case.

[46] Except for the de minimis amount associated with the working capital in the rate base.

Figure D: Customer Costs – Short-Term Replacement

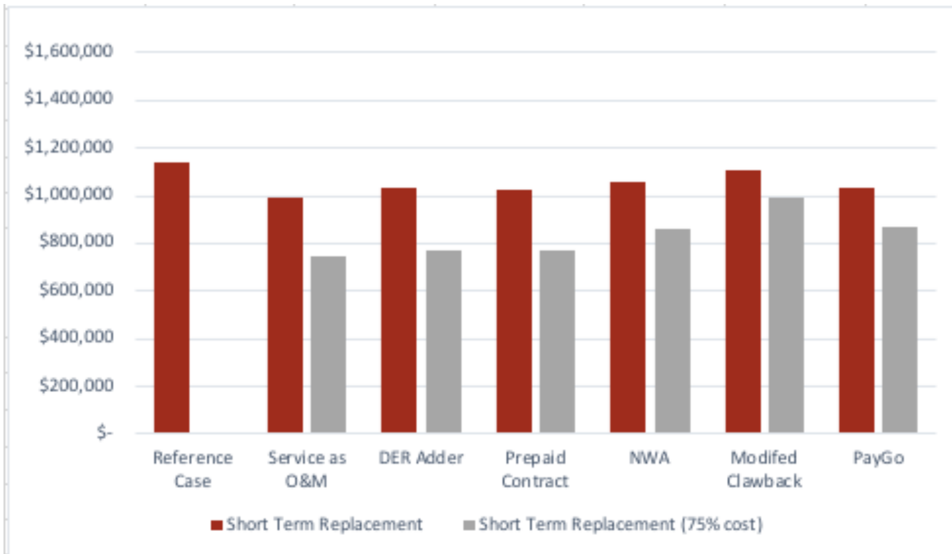
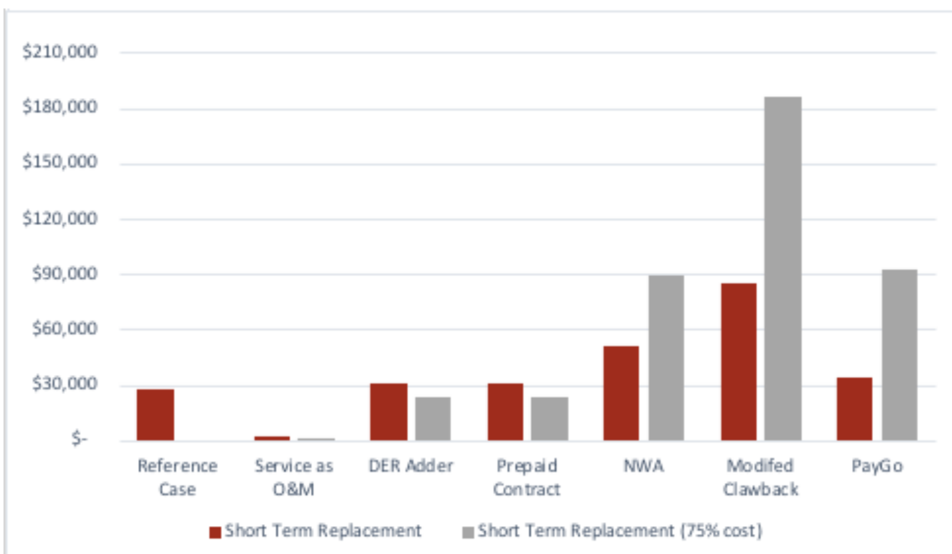


Figure E: Project NPVs – Short-Term Replacement



Scenario 2: Short-term deferral of a utility distribution investment

In this scenario (see Table 3), a service solution is assumed to defer the need for a utility distribution upgrade for five years. In year six, the utility invests in a distribution solution as it normally would. We assume that the distribution investment has a life of 40 years.

In a departure from the other two scenarios, we did not assume that the service solutions would cost the same $1 million as the Reference Case. If that were the case, the utility would pay substantially more for the deferral than it was worth. Why put in a temporary fix when the utility can solve the problem for 40 years at the same cost? In order for the service-based deferral to be more cost effective on a yearly basis, it only needs to beat the annual cost of the of the $1 million traditional investment. For this reason, we set the yearly service cost at $73,300, which amounts to an NPV of $1 million when paid out over a 40-year period. This is not an unrealistic assumption for a deferral, as the solution may need to provide only a small amount of additional capacity (for instance, relieving 50 kW on a 1 MW circuit) if the load growth on the constrained circuit is gradual. It also allows for system needs to be met in smaller increments[47] and the option to cancel a future upgrade if the anticipated load growth does not materialize.

We also note that a limitation in our modeling surfaces in this scenario. Our model assumes that the same $1 million invested by the utility in year 1 would be invested in year 6 to meet the same need, when in reality, the costs of meeting that need are likely to escalate during those five years. So while our model discounts future cash flows to provide an NPV, it does not correspondingly increase the cost of future capital investments. This both decreases the future costs and future returns from the distribution asset placed into service in year 6 relative to the same investment in year 1. The results for this scenario include the costs and earnings for both the five-year, service-based deferral and the full 40 years of the utility asset (except for the Reference Case, which is the utility investment alone). Because the costs of the capital investment are not escalated, they are lower on an NPV basis than they likely should be when the capital investment is made in year six. For this reason, the model likely underestimates the costs and earnings of all of the options except for the Reference Case in this deferral scenario.

[47] Distribution upgrades are often "lumpy" and are only available at certain capacity increments. DER may provide smaller additions that may better fit a particular need.

Table 3: Modeling Results for the Short-Term Deferral Scenario

Short Term Deferral of 40 Year Utility Distribution Investment			
Statistics	**Option**	**Equivalent Cost Case**	**Lower Cost Case**
NPV Cost to Customer	Reference Case	$ 1,641,154	$ 1,641,154
	Service as O&M only	$ 1,477,962	$ 1,402,910
	DER Adder	$ 1,489,664	$ 1,411,687
	Capitalization of Pre-Paid Contract	$ 1,488,235	$ 1,410,614
	NWA Shared Savings	$ 1,524,847	$ 1,465,811
	Modified Clawback	$ 1,634,086	$ 1,599,764
	PayGo	$ 1,499,544	$ 1,436,418
NPV Utility Earnings (Accounting Earnings)	Reference Case	$ 385,808	$ 385,808
	Service as O&M only	$ 278,825	$ 278,426
	DER Adder	$ 287,608	$ 285,013
	Capitalization of Pre-Paid Contract	$ 305,879	$ 298,717
	NWA Shared Savings	$ 333,357	$ 340,141
	Modified Clawback	$ 395,996	$ 426,165
	PayGo	$ 294,908	$ 303,488
Project NPV (Shareholder Value)	Reference Case	$ 128,385	$ 128,385
	Service as O&M only	$ 87,285	$ 87,089
	DER Adder	$ 96,068	$ 93,676
	Capitalization of Pre-Paid Contract	$ 95,743	$ 93,433
	NWA Shared Savings	$ 123,221	$ 134,858
	Modified Clawback	$ 204,456	$ 234,828
	PayGo	$ 103,368	$ 112,151
	NPV 3rd Party Payments	$ 292,559	$ 219,420
	Yearly Service Payments (5 years)	$ 73,316	$ 54,987
	Pre-Paid Contract Payment	$ 312,468	$ 234,351
	Amortization Reg Asset + Dx investment Yrs	5 + 40	5 + 40
	Amortization PayGo + Dx Investment Yrs	1.67 + 40	1.67 + 40

*In this model, the yearly cost of the service for the 5 year deferral is set equal to the yearly service cost in our 40 year model. This best approximates the yearly value of the 1 million capex investment. The full NPV 1 million equivalent used in other models cannot be used here because it would far exceed the base case. The service options need to do better than the yearly cost of the reference case to have value.

The key results of this scenario are as follows:

Reference Case – In the Reference Case the utility invests in capex for a project that has a useful life of 40 years, and there are no payments to service providers. The project NPV is $128,400, the NPV of earnings is $385,800, and the cost to customers is $1.64 million. In this scenario the utility receives accelerated tax depreciation and also incurs indirect costs for property taxes and O&M.

Service as O&M – This option has the lowest earnings and project NPV of any option. However, this option does provide greater earnings here than in other scenarios. This is because the service expenses (with low earnings) are combined with the earnings from a 40-year capital investment placed into service in year six. Out of the $278,900 in NPV earnings provided with this option, all but a few thousand dollars are provided by earnings from the deferred capital investment.

DER Adder – In the DER Adder option, the project NPVs are $96,000, the utility earnings NPVs are $287,600 and costs to customers are $1.49 million. This option has $32,300 lower project NPV and $151,500 lower costs to customers than the Reference Case. This option compares a little unfavorably to the Reference Case for the utility but is better for customers. This is because while the 4% markup on the contract provides lower costs to customers, it also provides lower earnings and project value during the 5-year contract. Even though the utility eventually makes the capital investment in year six, this does not overcome the loss of earnings early on. This is due to the discounting of the cash flows due to timing of the utility investment.

Capitalization of a prepaid contract – The prepaid contract option has a lower project NPV and lower costs to customer than the Reference Case. Lower costs to customers and project NPV result because of the relatively lower costs early on; offset by lower cash flows caused by the large prepayment; followed by higher costs/cash flows than the Reference Case later on. This does not negate the lower costs/earnings early on, again due to the discounting of the future cash flows.

NWA with Shared Savings – The NWA Option produces a comparable project NPV with lower costs to customers relative to the Reference Case. However, it provides lower accounting earnings to the utility. This is because during the initial five years, earnings for the utility are lower than the Reference Case. Again, the future cash flows of the deferred utility investment are lower due to discounting.

Modified Clawback – Under the Modified Clawback option, it is assumed that the utility has a service contract for five years and files a rate case effective in year 4. Upon the implementation of the new rate case in year 4, the utility's earnings on the contract end (other than earnings on working capital) but the contract continues until year 5. Also at that time, the utility invests in the traditional 40-year solution. This option produces a highly profitable project NPV, however, the cost to customers is roughly the same as the Reference Case as only a small portion of the savings are retained by customers. During the first three years, earnings are much higher than in the Reference Case because the utility avoids the $1 million in capex and retains all of the savings. Then in years 4-5, they are lower since the utility is only paying the annual contract costs. Costs to customers are higher under this option because customers continue to pay the higher cost of service for the first three years as if the utility investment were made. This is followed by a lower cost of service for two years to reflect the service contract costs and then the higher costs associated with utility investment in year 6.

PayGo – The PayGo option produces a lower project NPV and utility earnings and lower costs to customers. This option compares unfavorably to the Reference Case from the utility perspective; given lower project NPV and accounting earnings to the utility. A lower project NPV results in this option because of very low cash flows in years 1-5. This approach leaves the utility with a relatively small rate base upon which it earns in the early years. And due to the relatively small cost difference between this option and the Reference Case, the scaling of shared savings provides only a modest amount of incentive.

Figure F: Customer Costs – Short-Term Deferral

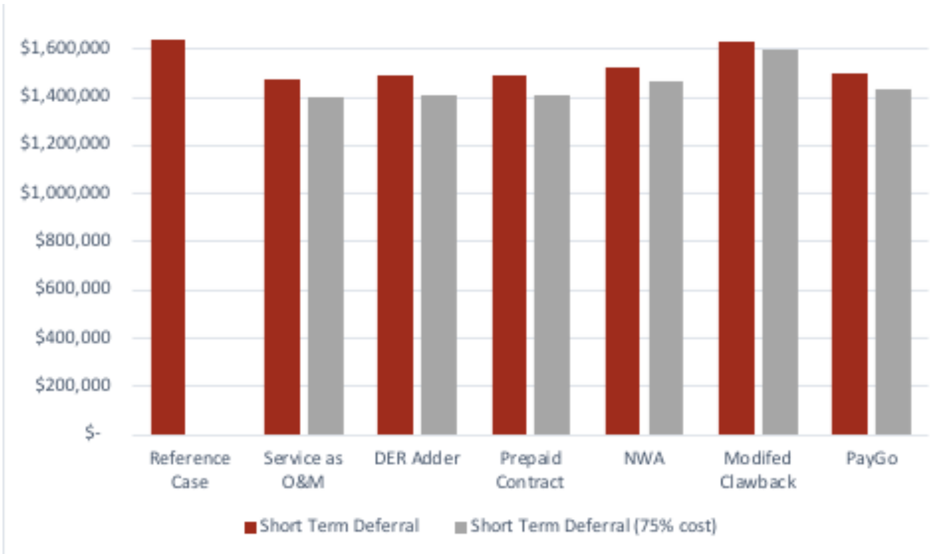
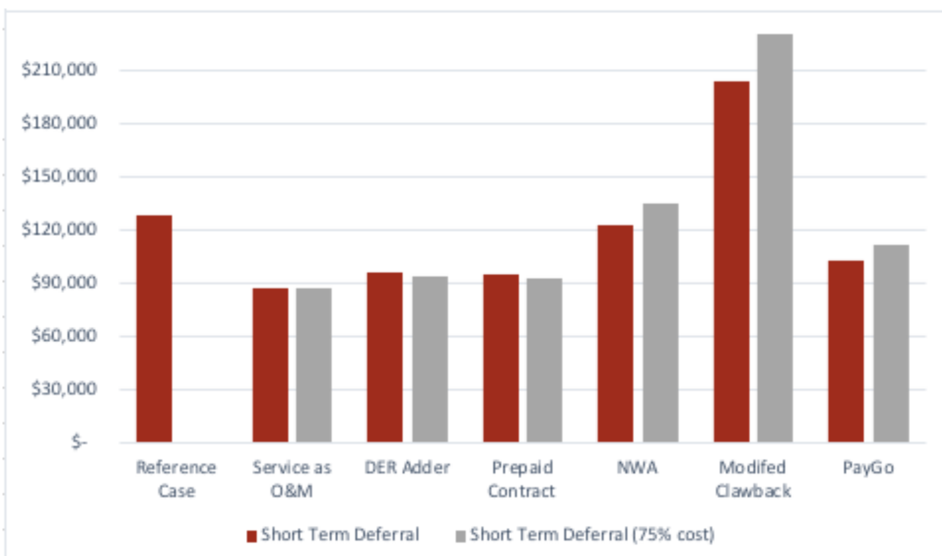


Figure G: Project NPVs – Short-Term Deferral



Scenario 3: Long-Term Replacement of a Utility Distribution Investment

For the long-term replacement scenario, we modeled a 40-year service contract that completely replaces a utility capital investment. We chose 40 years as reasonably representative of a typical utility investment cycle for a long-term capital project. As with Scenario 1, the Equivalent Cost Case assumes that the NPV of the service contract would be the same as the NPV of the Reference Case $1 million utility investment. We also modeled the Lower Cost Case where the NPV of the service contract was 75% of the NPV for the Reference Case investment. Service contract payments can be made annually or they can be pre-paid, depending on the option. The NPV of the payments however will be the same across all options ($968,100 and $726,100 respectively for the two cost cases). The corresponding annual payments are $73,300 and $55,000, respectively. Table 4 presents the Long-Term Replacement Scenario results for the two cost cases.

Table 4: Modeling Results for the Long-Term Replacement Scenario

Long Term Replacement of 40 Year Utility Distribution Investment			
Statistics	**Option**	**Equivalent Cost Case**	**Lower Cost Case**
NPV Cost to Customer	Reference Case	$ 1,641,154	$ 1,641,154
	Service as O&M only	$ 993,447	$ 745,085
	DER Adder	$ 1,032,173	$ 774,129
	Capitalization of Pre-Paid Contract	$ 1,178,331	$ 883,748
	NWA Shared Savings	$ 1,224,168	$ 958,760
	Modified Clawback	$ 1,149,571	$ 941,939
	PayGo	$ 1,255,152	$ 1,020,731
NPV Utility Earnings (Accounting Earnings)	Reference Case	$ 385,808	$ 385,808
	Service as O&M only	$ 5,284	$ 3,963
	DER Adder	$ 34,347	$ 25,760
	Capitalization of Pre-Paid Contract	$ 415,821	$ 311,866
	NWA Shared Savings	$ 450,221	$ 368,162
	Modified Clawback	$ 122,455	$ 151,702
	PayGo	$ 199,150	$ 208,928
Project NPV (Shareholder Value)	Reference Case	$ 128,385	$ 128,385
	Service as O&M only	$ 2,040	$ 1,530
	DER Adder	$ 31,103	$ 23,327
	Capitalization of Pre-Paid Contract	$ 137,896	$ 103,422
	NWA Shared Savings	$ 172,296	$ 159,718
	Modified Clawback	$ 119,211	$ 149,269
	PayGo	$ 195,906	$ 206,495
	NPV 3rd Party Payments	$ 968,135	$ 726,101
	Yearly Service Payments (40 years)	$ 73,316	$ 54,987
	Pre-Paid Contract Payment	$ 1,034,017	$ 775,512
	Pre-paid Amortization years	40	40
	PayGo Amortization Years	13.33	13.33

Reference Case – In the Reference Case, the utility invests in capex for a project that has a useful life of 40 years. For this option, there are no payments to service providers. The project NPV is $142,200 and the cost to customers is $1.64 million (this is the same as the Reference Case in the Short-term Deferral Scenario). Under this option, the utility receives accelerated tax depreciation and also incurs indirect costs for property taxes and O&M.

Service as O&M – While this option provides the lowest customer costs of any option, it provides almost no earnings to the utility. The NPV accounting earnings it provides to the utility of $5,300 is a fraction of the Reference Case earnings ($385,800). Looking at the value to the utility and its shareholders from a project NPV perspective, this option only provides $2,000 in value, nearly a 99% decrease from the Reference Case. This is because the only earnings provided from this option come from the small amount of rate base used to fund working capital.

DER Adder – The project NPV shows a profit of $31,000, accounting earnings are $34,300 and costs to customers are $1.03 million. The option has $97,200 lower project NPV, $351,000 lower accounting earnings, and significantly lower costs to customers than the Reference Case. Consequently, this option compares unfavorably to the Reference Case for the utility but is much better for customers. This is because the 4% markup on the contract provides lower project value and accounting earnings (and costs to customers) than the utility's investment during the 40-year contract, especially in the early years. The results are similar for both the Equivalent Cost and Lower Cost cases.

Capitalization of a Prepaid Contract – This option has higher project NPV value and accounting earnings for the Equivalent Cost Case when compared to the Reference Case. The economic and accounting earnings decrease in the Lower Cost Case. The lower service costs in the Lower Cost Case directly translates into significantly lower costs to customers than the Reference Case. In the Equivalent Cost Case, lower costs to customers result because of the relatively lower costs throughout the 40-year contract as the utility avoids O&M expenses and property taxes due to the service contract.

NWA Shared Savings – The NWA option relative to the Reference Case produces improved utility project value and accounting earnings for both cost cases, in addition to lower costs to customers. Because of the shared savings approach underlying the NWA option, earnings exceed those provided by the prepaid option for both cost case. Counterintuitively, the earnings decline (in both accounting and economic terms) in the Lower Cost Case despite the shared savings mechanism. This indicates that over a long-term scenario, the rate base is more effective at providing earnings compared to the shared savings mechanism. Utility cash flows are higher overall because after the initial prepayment of the contract, annual costs are largely non-cash. However, even though there is no upfront tax benefit associated with the prepayment and an assumed loss of accelerated depreciation in this scenario which raises costs to customers, this does not negate the lower costs as the utility avoids O&M expenses and property taxes due to the service contract over the life of the contract.

Modified Clawback – Under the Modified Clawback option, it is assumed that the utility has a service contract for 40 years and files a rate case effective in year 4. Upon the implementation of the new rate case in year 4, the utility's earnings on the contract end but the contract continues until year 40. This option produces lower project value and accounting earnings for the utility and lower costs to customers overall relative to the Reference Case. During the first three years, cash flows are much higher than in the Reference Case because the utility avoids the $1 million in capex but revenues are unchanged. Then in years 4-40 economic earnings drop substantially since they are derived from working capital in the rate base to pay for the periodic service expenses. From years 4-40, customers reap all of the cost savings associated with paying for the service as a traditional O&M expense.

Pay-as-you-go – The PayGo option produces significantly higher utility project NPV but lower accounting earnings and lower costs to customers. Higher cash flows result in this option because the contract costs are spread over 40 years rather than a large up-front payment associated with capex. Rate base is gradually increased then gradually decreases over the 42-year timeframe. Project value and accounting earnings are low initially and increase over time then decrease towards the end of the term due to the timing of the cash flows and the method used to spread costs out over future years for recovery. This spreading of costs and cash flows and the related impacts of discounting of such costs also causes the costs to customers to be lower overall than in the Reference Case.

Figure H: Customer Costs - Long-Term Replacement

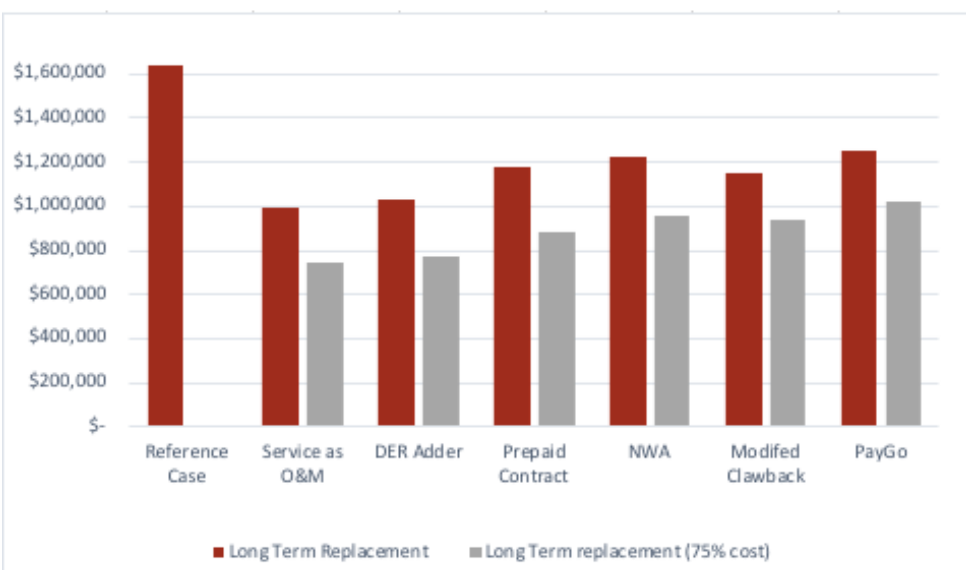
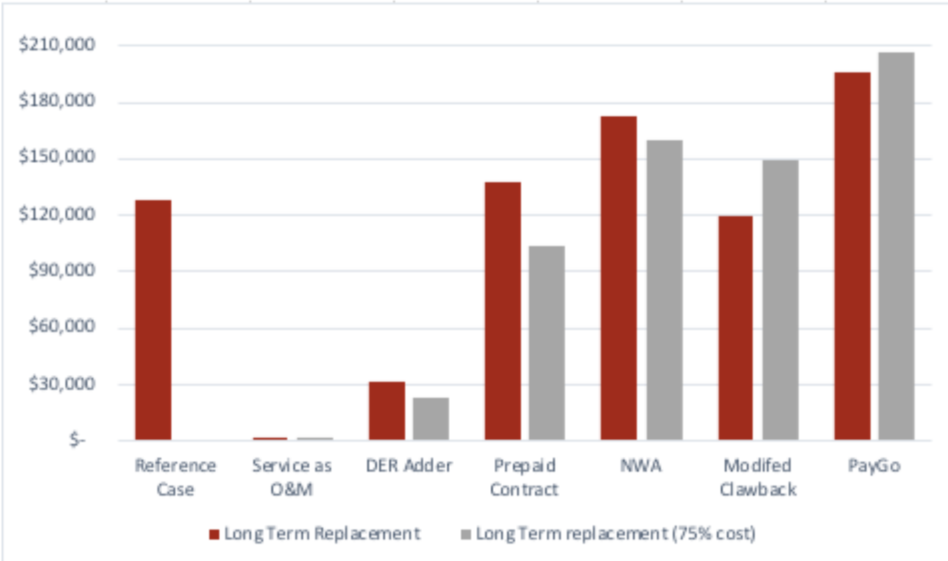


Figure I: Project NPVs - Long-Term Replacement



Overall Observations

A summary of the key metrics for all options and scenarios is provided in **Error! Reference source not found.** below. Additionally the results are displayed in the figures that follow , grouped by deployment scenario. Those results that are above the Reference Case have higher project NPVs, while those results that are to the left of the Reference Case have lower customer costs.

Table 5: Customer Costs and Project NPVs for all Options and Scenarios

		Short Term Replacement (Equivalent Cost)	Short Term Replacement (Lower Cost)	Short Term Deferral (Equivalent Cost)	Short Term Deferral (Lower Cost)	Long Term Replacement (Equivalent Cost)	Long Term replacement (Lower Cost)
Reference Case	NPV Customer Cost	$ 1,140,435	$ 1,140,435	$ 1,641,154	$ 1,641,154	$ 1,641,154	$ 1,641,154
	Project NPV	$ 28,476	$ 28,476	$ 128,385	$ 128,385	$ 128,385	$ 128,385
Service as O&M only	NPV Customer Cost	$ 993,453	$ 745,090	$ 1,477,962	$ 1,402,910	$ 993,447	$ 745,085
	Project NPV	$ 2,222	$ 1,667	$ 87,285	$ 87,089	$ 2,040	$ 1,530
DER Adder	NPV Customer Cost	$ 1,032,179	$ 774,134	$ 1,489,664	$ 1,411,687	$ 1,032,173	$ 774,129
	Project NPV	$ 31,286	$ 23,464	$ 96,068	$ 93,676	$ 31,103	$ 23,327
Pre-Paid Contract	NPV Customer Cost	$ 1,027,448	$ 770,586	$ 1,488,235	$ 1,410,614	$ 1,178,331	$ 883,748
	Project NPV	$ 31,105	$ 23,329	$ 95,743	$ 93,433	$ 137,896	$ 103,422
NWA	NPV Customer Cost	$ 1,054,500	$ 859,137	$ 1,524,847	$ 1,465,811	$ 1,224,168	$ 958,760
	Project NPV	$ 51,408	$ 89,786	$ 123,221	$ 134,858	$ 172,296	$ 159,718
Modified Clawback	NPV Customer Cost	$ 1,104,921	$ 991,342	$ 1,634,086	$ 1,599,764	$ 1,149,571	$ 941,939
	Project NPV	$ 85,879	$ 186,479	$ 204,456	$ 234,828	$ 119,211	$ 149,269
PayGo	NPV Customer Cost	$ 1,037,090	$ 866,615	$ 1,499,544	$ 1,436,418	$ 1,255,152	$ 1,020,731
	Project NPV	$ 34,580	$ 92,577	$ 103,368	$ 112,151	$ 195,906	$ 206,495

Figure J: Modeling Results for the Short-Term Replacement Scenario

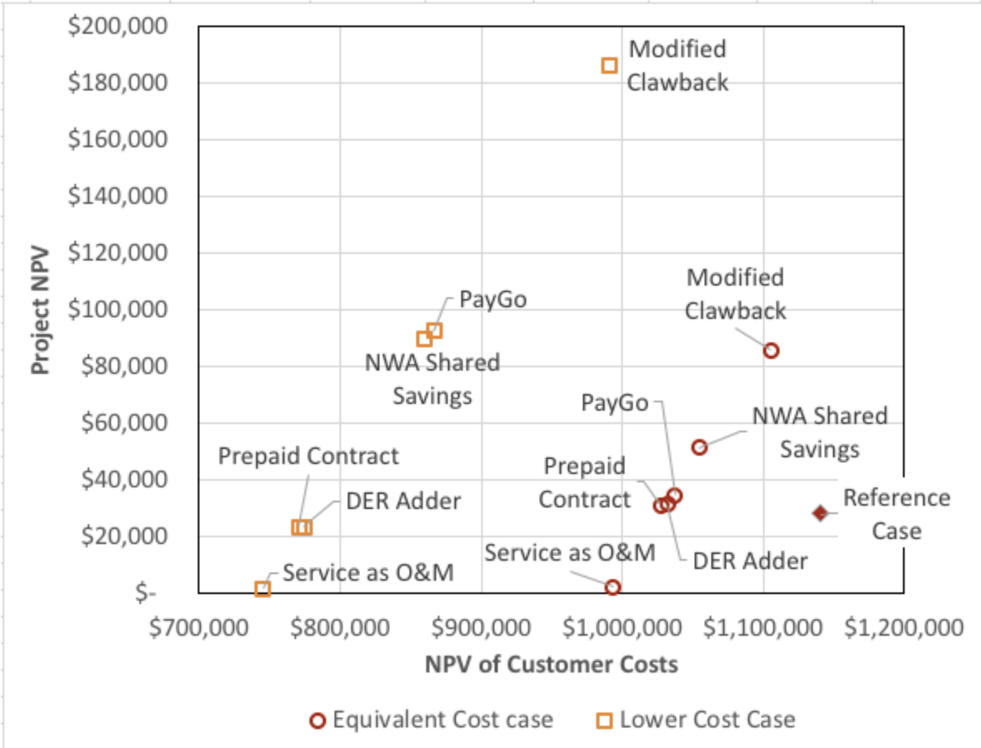


Figure K: Modeling Results for the Short-Term Deferral Scenario

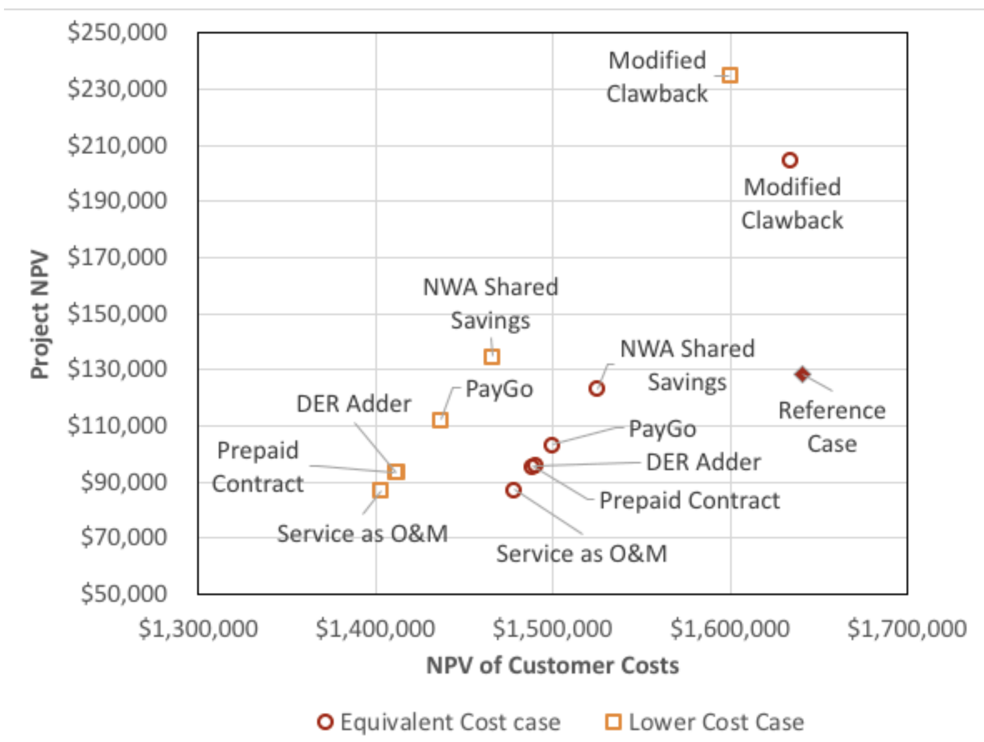
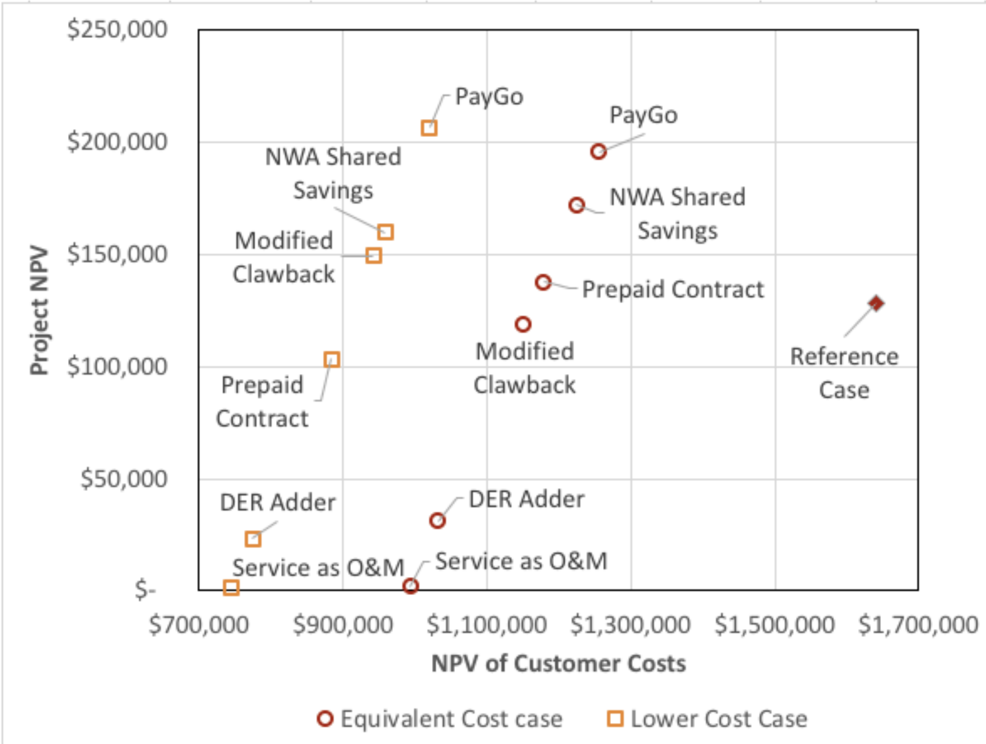


Figure L: Modeling Results for the Long-Term Replacement Scenario



Overall Performance of the Options and Potential Improvements

Service as O&M – While this option provides the lowest cost to customers in all scenarios, it does so through lowering utility earnings to a de minimis level. This exemplifies the problem with the prevailing cost-of-service model. Over the long-run, were a utility to frequently pursue service solutions, it would erode earnings and could ultimately undermine the financial stability of the utility, placing customers at risk. Given these impacts, a utility may opt against using a service even in cases where it is the most competitive solution.

DER Adder – Compared to the other options, the main benefit of the DER Adder option is its simplicity. There are no counterfactuals or avoided investments against which to measure the savings. The 4% adder is simply applied to the cost of the service expenditure, regardless of the cost that it replaces. This likely makes it the easiest option to implement. However, it also has some drawbacks. First and foremost is the value to the utility in terms of long-term utility earnings and project NPV. While the DER Adder provides a project NPV that is equivalent to the Reference Case in the Short-Term Replacement scenario, it provides lower earnings in the Short-Term Deferral scenario and significantly lower earnings in the Long-Term Replacement scenario. We estimate that just to level the project NPV with the avoided

Reference Case investment in the Long-Term Replacement scenario, the adder would need to be 17% for the Equivalent Cost Case and 23% for the Lower Cost Case. The shortfall arises from both the length of the Reference Case investment (the longer the lifespan, the greater the earnings from rate base) and the cost savings (the lower the costs, the lower the earnings). Although this outcome is good for customers, it may limit utilities from actually pursuing this option. This indicates that this simple approach may be too simple. Scaling the adder based on the length of the capital investment avoidance or deferral might address one of the factors, but not the impact of reduced earnings from cost savings. Addressing the difference in costs and the impact on earnings would require a comparison against the avoided Reference Case investment, reducing this option's simplicity.

Capitalization of a Prepaid Contract – In most of the scenarios, the Prepaid Option compares well to the Reference Case in terms of project NPV in the Equivalent Cost Case. Costs to customers across all three scenarios are marginally lower than the Reference Case. The slight decrease in total costs is due to our assumption for the purpose of modeling that the payments to the service provider equal the present value of the avoided utility investment, which for reasons we discussed earlier, is likely to favor the service expenditure in terms of cost-effectiveness. Despite the lower cost to customers, the prepaid option receives a slight boost in earnings due to the fact that it is ineligible for accelerated tax depreciation, increasing earnings from rate base but therefore also increasing costs, all other things held constant. The lack of a shared savings mechanism means that utility earnings decrease, and therefore the utility lacks incentive to choose the service when the cost of the service is significantly less than the Reference Case investment.

The prepaid contract option may have other limitations. Prepaying a contract for more than five years is likely to be impractical for most utilities, as it would limit their choices in the future, and potentially undermine some of the benefits of having a service contract in the first place. Arguably, a key benefit of a service contract over a traditional long-term investment is the optionality it provides the utility to pursue different vendors and solutions, which is lost with a 40-year contract. On the financing side, such a large prepayment would need to be significantly discounted. We used the full utility WACC (6.80%) in our model to discount the prepaid option instead of a more realistic 5%. Recall that this discount rate was used to set the prepaid option on equal NPV terms with the periodic payment-based options, for which we did not create a price escalator because we did not think we could accurately estimate the change in the future cost of services. Using the more realistic 5% yearly discount, the cost of the prepaid option in our full cost Long-Term Replacement scenario increases by nearly $300,000 to $1.47 million. While the prepaid option appears unworkable over long periods of time, these discounting issues have minimal impact over a 5-year period, and this option remains a good performer for leveling earnings between similarly priced traditional utility solutions and service solutions over shorter terms.

NWA Shared Savings – The NWA option has similar characteristics to the prepaid option as it is based on the same prepayment concept for a service, but the addition of the 30% savings sharing incentive makes it a stronger performer in all scenarios in terms of utility earnings. Utility earnings increase meaningfully in almost all of the Lower Cost Case scenarios, as the shared savings mechanism converts 30% of the savings to earnings. The cost to customers remains lower, in all cases relative to the Reference Case. There is one scenario where the NWA option yields lower utility earnings in the Lower Cost Case compared to the full cost case, and that is the Long-Term Replacement scenario. And in the case of the PayGo option, project NPV edges up only slightly in the Lower Cost Case compared to the Equivalent Cost Case despite the benefit of a 44% shared savings incentive. This indicates that the effectiveness of shared savings mechanisms, as we have modeled them, decreases the longer the time period. With both of these two options, we take the share of the NPV savings relative to the Reference Case option (30% in the NWA option and a share that is proportional to the percentage savings in the PayGo option) and divide them evenly across all 40 years. This makes the yearly incentive small, and even smaller in NPV terms given the impact of discounting for future years. The other impact is that over long amortization periods, earnings from rate base make up a higher percentage of total earnings as compared with earnings from shared savings. Because of this, if the rate base earnings decrease, the increase in shared savings is not commensurate, and total earnings decline overall despite the shared savings. This indicates that some changes to the mechanism might make it more effective in terms of utility motivation, but this would come at the cost of increasing the cost to customers. Potential solutions to this problem could take the form of some combination of front-loading the payout of the shared savings incentive in the earlier years or increasing the shared savings percentage for longer deferral or avoidance scenarios.

Modified Clawback – The Modified Clawback, in terms of costs to customers, is the lowest performer out of the five alternative options. In the Short-Term Deferral scenario, the costs to customers of the Modified Clawback option nearly equals that of the Reference Case. In both of the Short-Term scenarios, the Modified Clawback overcompensates the utility in the Lower Cost Case. In the Long-Term Replacement scenario, both the costs to customers and earnings to utilities are low. This is because the clawback is a short-term mechanism, providing additional earnings only during the first three years of its application, because of the assumption of re-filing a rate case after three years. Thus, this mechanism becomes less effective over long-time periods. The three years used for the Modified Clawback in our model, as we have noted previously, may also be optimistic, as utilities will usually need at least a year to identify and implement an alternative solution after a rate case. If the Modified Clawback is in effect for less than three years, costs to customers will decrease as they will retain more of the savings and utility earnings will be lower. Nevertheless, the Modified Clawback remains a flexible option because it allows service payments to be made yearly, and the modification in ratemaking is also simple.

PayGo – Our new option, Pay-as-you-go, performs well in terms of cost to customers relative to the Reference Case in all scenarios and is roughly even with the two other regulatory asset options (Prepaid Contract and NWA Shared Savings). It also performs well in consistently providing a favorable project NPV, except in the case of the Short-Term Deferral, where it is slightly lower than the Reference Case. Our use of one third of the service term for amortization of the regulatory asset provides a small amount of earnings from rate base for the short-term scenarios and large rate base earnings for the long-term scenario. This indicates that more stability in earnings from rate base could be provided by increasing the amortization period in the short-term scenarios and decreasing it in the long-term scenario. This would require deviating from a fixed percentage of the deferral or avoidance period, but the flexibility already allowed in the amortization of regulatory assets would accommodate this.

As we discussed above, the shared savings mechanism becomes less valuable over time since the incentive is provided in equal increments on a yearly basis. In the Short-term Replacement Scenario using the Lower Cost Case, 77% percent of the project NPV comes from the shared savings mechanism. In the Long-Term Replacement Lower Cost Case, shared savings provides only 39% of the project NPV. This is despite the fact that the shared savings incentive is much larger in the Long-Term Replacement Scenario (44% vs. 32%) due to the higher cost savings. While the variables that we included in the PayGo option provides good performance in terms of both costs to customers and value to utilities (project NPV), the real benefit of the mechanism is its flexibility. Both the amortization period and shared savings mechanism can be changed to target specific outcomes and reduce variability. And the key promise that it holds is providing rate base earnings from a yearly service payment, allowing for the payment arrangements and time periods to better fit business needs.

CONCLUSIONS AND RECOMMENDATIONS

We began this paper with the premise that price signals are important for directing business behavior. Utilities certainly are concerned with the quality of service to their customers, as well as reliability, safety, and affordability of their service, but all things being equal, earnings do matter.

This paper does not presume that new services and technologies will necessarily be more cost effective; that was not the question that we attempted to address. Instead, we were concerned with the price signals that regulation sends to utilities when service solutions are more cost effective and offer better value. How will a utility respond given the conflicting signals of cost and service value versus the earnings opportunity that is foregone if it puts customers first and shareholders second? The answer may not be the same in every case. However, the way to ensure customers get the best value every time is to work to minimize these conflicts between customer and shareholder interests in the first place.

The key observation that we take away from this study is that while it is not entirely clear which option is the best performer in all scenarios (there are clearer leaders in specific circumstances), the majority of the alternative options do better than business-as-usual when there are cost savings for customers to be realized by choosing a more cost-effective service. This indicates that there is value to investigating these concepts in more detail and refining them for more widespread implementation.

As a first step, regulators can weigh the options and determine which works best for their own goals. Given the importance of the systems that they regulate, their impact on the economy, the overall energy goals they are seeking to achieve, and the fact that electric bills impact nearly every person in some way, it is understandable that regulators will want to take a cautious approach. Those options that have a good deal of prior precedence will be a safe choice for commissions that prefer tested approaches.

If a well-tested approach is preferred, then the pre-paid contract option is a good candidate for a short-term deployment scenario. It performs similarly to the Reference Case in the Cloud Computing (Short-term Replacement) scenario, though the value to the utility in a Short-Term Deferral scenario may be insufficient. While we do not have public citations to provide (the contracts and financing details are not public), we understand that this solution has been implemented already. New York has issued an order that allows utilities to pre-pay and capitalize licenses for cloud computing. Utilities and regulators in these cases believed it was consistent enough with standard practice and accounting rules to move forward without regulatory changes. And nearly every commission and every utility has experience with pre-paid contracts and regulatory assets of some sort.

If incenting greater cost effectiveness is a goal, then implementing a shared savings mechanism in addition to the pre-paid contract option is a potential approach. New York has already tested this for more traditional utility system investments in the form of their NWA mechanism, and there are several projects in New York using the mechanism that can provide other states with useful information on implementation. New York implemented the NWA mechanism using an additional earnings incentive based on a 30% share of NPV benefits using the Societal Cost Test, but we modeled it based on a 30% share of NPV cost savings to customers. Regulators need not be limited by those options. The scaling incentive mechanism that we used for our PayGo option could also be implemented on a pre-paid contract rather than the regulatory asset that is accumulated over time in our PayGo concept. And there are several other methods of applying shared savings that regulators could consider.

We do ultimately believe, however, that for services to be fully integrated into utility procurement needs, the industry will need to move beyond approaches that rely on pre-paid contracts. While they performed well in our 5-year scenarios, they are both impractical and costly for long-term capex replacement or deferral. And in order for utilities to get the most value from these services, they will need to be able to contract for these services for varying lengths and have the flexibility to choose a different solution (be it service or capital) when it is clear than an alternative is better. We have proposed the PayGo option as a way of overcoming the drawbacks of the pre-paid options, and we believe that while it will require some changes in regulatory and accounting practices, it can function within existing accounting rules. Our hope is that this paper serves as the beginning of a discussion, and that others can critique and improve upon our idea, or propose ones of their own.

Our overall conclusion is that, however well the cost-of-service regulatory model has served us over the past decades, it has remained relatively static while the rest of the economy is increasingly taking advantage of the benefits that a service-based model has to offer. We do not see this trend abating, and it may indeed accelerate, which makes it imperative for the utility regulatory model to be brought into alignment. With an approach that puts service solutions on equal footing with capital investments for utilities, customers will benefit from more cost-effective and feature-rich solutions that may not otherwise be pursued. At the same time, utilities will be rewarded for pursuing services that provide new benefits to customers and harness privately-owned resources that offset their own investments without fear that doing so will erode earnings for them and their investors. Finally, service providers will benefit from market opportunity, which will ultimately increase competition, drive innovation, and promote the continuous improvement of these services and the value that they deliver.