YOU GET WHAT YOU PAY FOR:

MOVING TOWARD VALUE IN UTILITY COMPENSATION

PART 2 – REGULATORY ALTERNATIVES

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AMERICA'S POWER PLAN

ENERGY INNOVATION POLICY & TECHNOLOGY LLC

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EXECUTIVE SUMMARY

Like other corporations, investor-owned electric utilities' primary duty is to maximize profits for their shareholders. As Part I of this series explained in detail, utilities that operate under cost of service regulation (COSR) achieve a regulated rate of return on capital investments that almost ubiquitously exceeds their cost of raising funds, creating value for their shareholders. This regulatory model works reasonably well to align utility motivation with the public interest when rapid system build-out is the top goal for policymakers. In fact, without a rate of return above the cost of equity for utilities, the system would stagnate—no activities would be profitable. But when capital-based solutions are not preferred or new technology creates room for competition, COSR may create a disconnect between utility shareholder value and outcomes that most benefit society.

Today, opportunities exist for non-utility-owned, non-capital resources to meet societal goals at lower costs than conventional utility-owned capital investments. The rapid cost declines of wind and solar challenge the conventional model of large fossil fueled generation. Demand can now be dispatched alongside supply, leading to a much more flexible system. Rapid progress on both the cost and operational effectiveness of distributed energy resources (DERs) means that customers and third parties can, in some cases, provide services that avoid the need for significant deployment of utility capital.

Societal preferences have shifted too. For instance, many utility regulators require utilities to adopt low-carbon energy resources, while others have prioritized resilience, resource diversity, or customer choice as critical power sector outcomes. Regulators increasingly balance these priorities with axiomatic goals like customer satisfaction, safety, universal access, and affordability. Where non-capital strategies are the best fit to achieve least-cost provision of electricity that meets these societal goals, COSR is poorly suited to motivate the new role society needs the utility to play amidst these changes.

This paper examines three cases where COSR clearly motivates utilities to pursue sub-optimal outcomes compared to some alternative regulatory strategy. Each case compares how utilities and customers operating in a series of different regulatory models may fare, with a special focus on performance incentive mechanisms (PIMs) and revenue caps.

Two Key Tools: Performance Incentive Mechanisms and Revenue Caps
▪ **Performance Incentive Mechanisms** Regulators offer a financial upside or downside to utilities for performance against targeted outcomes via cash payments or incentive rates of return. Savings or profits can also be shared with customers. ▪ **Revenue cap** Regulators establish a benchmark for what an efficient level of utility expenditures would be and tie utility revenue to the achievement of that benchmark.

The cases in this paper draw on simplified financial models designed to provide high-level insights into whether and to what extent COSR and its alternatives can align utility shareholder value creation with societal value creation. In this analysis, effective realignment of utility motivation is not synonymous with the utility having higher *revenue* relative to COSR. Instead, successful realignment depends on whether investments that are more valuable to society create more *shareholder value* (utility profit) than those that fail to maximize the public interest.

Though the examples in this paper test scenarios in which DERs provide equivalent service at a lower price, utilities most likely must invest substantial amounts of capital into the electricity system in order to meet new public demands for resilience, environmental performance, and customer choice. But in some cases, DERs save customers money, improve customer satisfaction, and clean up the resource mix. **The purpose of this paper is to explore which regulatory models align utility profit with societal value under scenarios in which traditional, utility-owned, capital solutions may not be optimal for customers.**

REGULATORY ALTERNATIVES		
Case 1: Meeting demand growth on a distribution circuit		
Scenarios Examined	**Regulatory Models**	**Conclusions**
▪ Conventional substation upgrade - \$56M ▪ Utility-owned distributed energy resource (DER) alternative - \$47M ▪ Third-party DER alternative - \$43M	▪ Cost of service regulation (COSR) ▪ COSR + peak demand reduction performance incentive mechanism (PIM) ▪ COSR + rate of return on third-party DER investments ▪ Benchmarked revenue cap	▪ When compared to COSR, the three alternative regulatory models better align customer value and utility motivation ▪ The peak reduction PIM (B) and the rate of return on DERs (C) were insufficient to overcome the utility's return on capital under COSR ▪ Benchmarked revenue cap (D) creates the clearest alignment between utility value and customer value
Case 2: Utility grid modernization investment		
Scenarios Examined	**Regulatory Models**	**Conclusions**
▪ Utility-owned and operated grid mod - \$1.9B ▪ Incorporate third-party telemetry solution - \$1.6B	▪ Cost of service regulation ▪ Benchmarked revenue cap ▪ Benchmarked revenue cap with stretch factor	▪ Revenue caps create a powerful incentive for the utility to identify and implement less expensive third-party approaches to large investments when they are available

		▪ Stretch factors better encourage cost containment
Case 3: Balancing reliability, fuel price risk, and environmental performance		
Scenarios Examined	Regulatory Models	Conclusions
▪ PPA with large gas-fired power plant - $2.9B ▪ PPAs with gas-fired peaker, renewables, and DERs - $2.2B	▪ Fuel cost pass through ▪ Modified fuel cost adjustment mechanism ▪ CO_2 performance incentive mechanism (PIM) ▪ Revenue cap + CO_2 PIM + stretch factor	▪ Shifting fuel price risk onto utilities may result in unfair rewards or penalties; outcome-oriented regulation like CO_2 PIMs or a revenue cap can align utility motivation directly with societal goals. ▪ A revenue cap could be used in conjunction with PIMs to motivate utilities to identify the least-cost approach to reducing carbon emissions

Examined together, the financial models produced three key takeaways:

1. *Cost of Service Regulation (COSR) creates utility incentives that are misaligned with societal value in scenarios where non-infrastructure or non-utility-owned alternatives are superior from a societal perspective.*
2. *Performance Incentive Mechanisms (PIMs) hold the potential to monetize presently uncaptured benefits and costs in utility regulation, and to motivate utilities to perform against outcomes that society prioritizes.*
3. *Multiyear revenue caps can be a powerful tool to align utility shareholder value with non-infrastructure-based strategies to meet grid needs. These tools deserve greater consideration, alongside PIMs, in utility regulatory model discussions.*

Regulatory models should not be examined in a vacuum, however. There are real risks to implementing each of the regulatory models. For example, the powerful incentives created by revenue caps mean that they must be set at the right level or else risk unintended consequences. In areas where a preferred alternative provides non-monetized societal value, PIMs can be used to motivate desirable project attributes, but may result in arbitrary swings in compensation if the targets fail to anticipate technological potential or if they fail to adjust for macroeconomic or weather impacts outside the utility's control.

The paper concludes with options for regulators, utilities, and other stakeholders to experiment with gradual next steps. Improvement to the existing regulatory model holds immense potential to create value for customers and society.

The United States' power sector is in the midst of a transformation that is driven by rapid technology and policy progress. Where power systems were once almost entirely centralized, today networks are becoming more distributed (Newcomb et al., 2013). The policy priorities of the power sector have also expanded. The industry's traditional goals of safety, reliability, and universal access, while still paramount, are now supplemented by new priorities like reduced greenhouse gas emissions, resilience, and customer choice (Aggarwal and Burgess, 2014). Existing regulatory models have stretched to accommodate these goals, but there is a growing disconnect between utility profit maximization and achievement of multi-goal public policy priorities. If this disconnect is to be addressed, regulatory models will need to evolve to effectively drive the outcomes society demands from the power sector.

Investor-owned utility (IOU) managers have a fiduciary responsibility to create value—i.e. maximize profits—for their shareholders. The result is that IOU managers will seek to maximize investor value subject to the regulatory incentives they face. Recently, academics, consultants, and regulators have posited the present regulatory paradigm—cost of service regulation (COSR)—does not sufficiently align utilities' incentives with outcomes society values[1]. In other words, what is best for IOU shareholders is no longer best for consumers and society.

Societal Value

This paper examines electric utilities' motivation to maximize the public interest, particularly in response from new social demands. Examples of these outcomes include environmental performance, resilience, affordability and customer choice. However, different jurisdictions may value different outcomes. Throughout this paper, the term "societal value" refers to the outcomes listed here, but regulators and policymakers could just as easily include a broader set of societal goals such as low-income access, job growth, or access to third-party services.

COSR incents utilities to invest in capital when returns on these investments exceed the cost of attracting capital (Gordon, 1974). While regulatory "prudency" review provides a check against obviously inefficient investments, information asymmetry between utilities and regulators make COSR an inadequate tool to incent optimal investments, given the strong utility incentive to spend on capital. Instead, the regulatory model should incent only valuable capital investments that minimize costs while maximizing reliability, environmental performance, and other public interest goals.

Just as important as valuable investments, non-infrastructure or non-utility owned solutions to grid challenges are key to realizing resilient, clean, and affordable energy systems. Investments in data management or analytics capabilities alongside physical infrastructure will unlock new

[1] Discussions of new regulatory models range from in-depth reports like the Lawrence Berkeley National Laboratory's Future of Electric Utility Regulation series, stakeholder driven collaborative processes like the e21 Initiative in Minnesota, or proceedings like the Reforming the Energy Vision docket in New York .

opportunities to optimize system performance and cost. In some cases, clean distributed energy resources (DERs) will be more cost-effective at maximizing societal value than conventional investments (Neme and Grevatt, 2015). Unfortunately, utility shareholders under COSR receive limited upside—and, in the long run, potentially a large downside[2]—for pursuing non-utility solutions, despite their potential to create value for customers[3]. In fact, many utilities are presently incentivized to cut operational costs between rate cases in order to maximize returns. If an operational solution to a grid need is more efficient than a capital intensive approach, utilities' preference for the latter strategy will lead to a sub-optimal societal outcome.

In recent years, performance-based regulation (PBR) models have been offered as alternatives to address the challenges of COSR (Harvey and Aggarwal, 2013; Kihm et al., 2015; Woolf and Lowry, 2016). PBR is an umbrella term that encompasses a variety of regulatory mechanisms to motivate performance against a number of different outcomes. PBR mechanisms that target economic efficiency improvements are well understood, having been used for decades in both the United States and around the world (London Economics, 2010). However, PBR mechanisms that target social values like resilience or reduced environmental impact do not have as extensive a track record. Additional quantitative support is needed to ensure regulators that PBR mechanisms will successfully motivate a cleaner, more reliable, and more affordable electricity system.

This paper is meant to draw out whether and how different PBR models achieve better alignment of utility financial incentives, customer value, and accomplishment of outcomes when compared to COSR. The analysis is split into three sections. The first section offers a brief description of COSR and the PBR "toolkit" that has been developed to address its perceived shortcomings. The second section uses case studies to offer a window into how application of PBR mechanisms can align utility incentives with the outcomes society wants. Simple financial models of various PBR mechanisms will illustrate how new regulatory models can realign utility incentives in common investment decisions, and support regulators who are eager to achieve the outcomes customers want from the electricity sector. The final section draws out conclusions from the preceding analysis.

1. REGULATORY MODELS AND UTILITY MOTIVATION

COST OF SERVICE REGULATION

One major function of public utility regulation is to align the incentives of regulated utilities with the goals of the public. Throughout their histories, power utilities have been consistently asked

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[2] The consulting firm Scott Madden estimates the average realized rate of return is for investor-owned utilities is only 84 percent that of allowed levels. This shortfall is attributed, in part, to increasing penetrations of DERs and slow load growth (Scott Madden, 2014)

[3] In practice, utilities mostly face the downside of a disallowance if they pursue unnecessarily expensive investments. As discussed below, the prudence review standard upon which these disallowances are based is not easily applied in the face of information and resource asymmetries between utilities and regulators.

to meet goals of affordability, safety, reliability, and universal access to service (Lazar, 2011). For much of the 20th century, COSR was well-suited to deliver progress towards these goals (Hirsh, 1999), since they could be accomplished by rapid expansion of the capital base.

Under COSR, in exchange for exclusive state-granted franchise areas, regulators offer utilities cost recovery plus an allowed rate of return on infrastructure investments. But utility profits are not guaranteed under COSR (Southwestern Bell, 1923). In order for utilities to earn the rate of return authorized by regulators, their investments must be deemed prudent. The most common standard for prudency review is a relatively easy one to meet: assets must be 'used and useful.' While profits are not guaranteed under COSR, this model assures investors that prudently incurred infrastructure expenditures will provide stable returns.[4] The result is sufficient capital provided at a low enough cost to build an electric grid offering universal and reliable access to affordable power in the United States.

In the 1970s and 1980s, the case for COSR and fully vertically-integrated utilities began to slip. Where costs had once been kept low by constant improvements in power plant efficiency, physical constraints began to limit the heat rate and scale improvements that drove cost reductions throughout much of the twentieth century (Hirsch, 1999). At this point academics, industry professionals, and regulators began to focus on alternative means to identify and eliminate the power utilities' inefficiencies and better simulate competitive outcomes.

One popular strategy that emerged was to restructure some components of the industry value chain, particularly generation and sometimes retail. Restructuring was premised on a belief that technological changes had eroded both the economies of scale and scope that justified the existence of vertically-integrated monopolies (Kahn, 2004). However, even in jurisdictions that are "fully" restructured,[5] transmission and distribution networks continued to have natural monopoly characteristics where regulation is needed to balance firm health and customer welfare. In this context, regulators sought to develop new tools to replicate the incentives and efficiencies of competition in the remaining monopoly segments of the utility industry, including PBR.

PERFORMANCE-BASED REGULATION

PBR describes several regulatory tools to align utility performance with societal value. Some tools are designed to address the economic inefficiencies of COSR, while others motivate accomplishment of non-monetized outcomes. In addition to realignment of incentives, PBR mechanisms are also designed to overcome information asymmetries between regulators and utilities (Laffont and Tirole, 1993). Permutations of PBR—that mix and match policy mechanisms as well as policy goals—have been implemented in a variety of U.S. states and other countries

[4] Another source of variation in utility earnings in many jurisdictions comes from the volume of sales. If the volume of sales does not match expected quantities, then the utility may realize a ROR that is either lower or higher than that established by regulators. The same is true of the costs the utility incurs. If costs vary from expected levels, profits can rise or fall accordingly.

[5] Texas or the United Kingdom, for example.

around the world. The result is there is no single regulatory system that can be offered as the standard definition of PBR, but there are instead many isolated examples offering unique experiences and lessons.

Standards and incentives for reliability may be the most common form of performance-based regulation. Apart from penalties imposed by the North American Electric Reliability Corporation (NERC) and Federal Energy Regulatory Commission (FERC) for violations of voltage and frequency standards, U.S. state regulators and many other countries provide their utilities with incentives to maintain reliability (Hesmondhalgh et al., 2012). Like other societal values, investments to improve and maintain reliability require cost trade-offs. In a competitive environment, customers would be able select the provider with the right balance between reliable and cheap service. Alternatively, for a natural monopoly regulators step in as a proxy to establish what balance is optimal across different types of customers.

Initial applications of PBR in the United Kingdom (Ofgem, 2010) and several U.S. states (Comnes et al., 1995) emerged in the 1990s alongside restructuring, focusing on the remaining monopoly franchise to simulate the incentives a competitive firm would face. One early regulatory tool utilities adopted to achieve these desired outcomes was a price cap, under which rates are determined in advance and applied over a multi-year period (Comnes, 1995). Price caps simulate competition by offering firms an upside if they are able to cut costs compared to the revenue they collect under the cap, which serves as a proxy for the effect of other firms in a competitive market. Conversely, firms whose cost structures require higher revenue lose money under a price cap unless efficiencies are identified and captured or sales increase.

The definition of PBR began to expand when the theory of price cap regulation was put into practice. To start, regulators quickly realized that price cap regulation could lead utilities to cut costs to the point that they could no longer maintain acceptable levels of safety, reliability, and customer service (Ter-Mortirosyan, 2010). A common response to this issue was to add targeted financial incentives that offered combinations of upsides and downsides based on performance in areas of concern like customer service or reliability.

Jurisdictions that implemented PBR—particularly those outside the U.S.—also began to experiment with tools like benchmarking and information quality incentives[6] to address

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[6] A promising strategy to implement a revenue cap is to use an information quality incentive (IQI) mechanism, also known as "menus of contracts." For this, regulators establish a menu of different revenue caps from which a utility is able to choose. Some cap levels allow more certainty on revenues collected, but limit a utility's upside through a lower rate of retained cost savings (Laffont and Tirole, 1993). Other options set a lower revenue cap, but offer the utility an opportunity to earn increased returns via higher retention of savings. A firm that is capable of identifying cost-reduction benefits from choosing a cap that offers lower guaranteed revenues, but with relatively high upside. In contrast, a firm that believes it has very little room for additional cost improvements can opt for a high amount of guaranteed revenues, but must share a large proportion of any savings that are identified with customers.

Using this method, the regulator's goal is to reward the utility for accurately assessing their costs and revealing this information to regulators. A regulator's goal in using this tool is to create a menu that is "incentive compatible," meaning the utility is always better off when it accurately assesses and reveals its cost-structure.

information asymmetries between regulators and utilities under COSR (Ofgem, 2010). Finally, some jurisdictions, including the United Kingdom, have eliminated the “throughput incentive”—where utilities earnings are tied volume of sales—to align utility incentives with energy conservation (Regulatory Assistance Project, 2011). In these jurisdictions, revenue cap approaches have supplanted the original price cap formulation of PBR.

Today, U.S. states and countries around the world use regulatory mechanisms that can be thought of as part of the PBR “toolkit” that has developed since the 1990s. Many countries outside the United States use price cap regimes that do not differ substantially from those implemented across natural monopoly industries (e.g. telecommunications, water) in the 1990s, and several U.S. states use combinations of multi-year rate plans and targeted performance incentive mechanisms (Lowry and Woolf, 2016). While numerous regulatory tools can be described as PBR, this paper analyzes the following mechanisms[7]:

- **Multi-year rate plans (MYRP), price cap, or revenue cap**: A utility’s allowed revenues, rates, or a combination of the two are set for a defined period of time. If a utility’s costs fall above or below their cap, it retains some share of the cost savings or overruns.

  MYRPs can be set in terms of either price or revenue caps. While both approaches are designed to drive down the average cost of service, price and revenue caps may have very different impacts on utility motivation. A price cap encourages a utility to sell more units of energy in order to generate sufficient revenue to cover their fixed costs and create value for their shareholders. In contrast, a revenue cap does not reward utilities when they increase sales, but instead when they are able to decrease their average cost by identifying a more efficient mix of inputs[8]. A revenue cap applied across both operational and capital expenses, called TOTEX in the U.K., can also address utility bias towards capital investments.

  In both price and revenue cap formulations of PBR, the cap is usually either annually increased or decreased (in real terms) using escalators called “attrition relief mechanisms” and automatic adjustment clauses to modify rates so they account for exogenous factors like weather (Lowry and Woolf, 2016). Some MYRPs include a mechanism to share a proportion of savings with consumers on an annual basis. Other strategies allow utilities to retain all savings until the next rate review. In either case, a longer MYRP increases the “incentive power” of a regulatory strategy by increasing the size of earnings or cost overruns retained by utilities, while allowing for more experimentation and flexibility to minimize cost.

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[7] An extensive treatment of these mechanisms can be found in Lowry and Woolf 2016.

[8] A utility can also cut service quality in order to decrease cost. This issue is addressed in the section on performance incentive mechanisms, below.

- **Benchmarked revenue requirements**: Regulators establish a benchmark for what they deem to be an efficient level of utility expenditures and tie utility revenue to the achievement of that benchmark. These benchmarks can be developed based on actual expenses from a selection of similar utility firms, or simulated based on expected input costs (Jamasb, 2001). If cost inefficiencies in the industry are believed to be large, regulators can use "stretch factors" that assume increased efficiency over time.

  The efficacy of a benchmarked revenue cap approach (price caps are set aside hereafter[9]) depends on whether the cap is set at the right level. If the cap is set too low, the utility will be unable to provide shareholders with a fair return for their investment, hampering their ability to attract capital. If the cap is too high, ratepayers will overpay and utility shareholders receive windfall profits. Despite these challenges, benchmarking techniques have been developed to provide an alternative to the accounting-based methods used in COSR.

- **Performance incentive mechanisms (PIMs)**: Regulators offer a financial upside or downside to utilities for their performance against targeted outcomes. The upside can take the form of cash payments, shared savings, basis point adjustments to the utility's overall rate of return, or incentive rates-of-return on qualifying projects (Whited et al., 2015). By using PIMs, regulators can indicate areas of performance around which utilities should prioritize their planning and investments.

  For example, more than half of U.S. states offer utilities an opportunity to create shareholder value through targeted energy efficiency PIMs (Nowak et al., 2014). Furthermore, states like Illinois and New York are considering new PIMs that aim to align utility incentives with effective use of new grid technologies and a new role in managing network operations (NY PSC, 2015; Whited et al., 2015). Additional states either have considered or are considering similar mechanisms (CPUC, 2016).

  For jurisdictions that adopt a revenue cap, PIMs are an important tool to ensure cost cutting incentives of MYRPs motivate performance against outcomes not easily priced in market and do not lead to reductions in service quality (Mandel 2015). PIMs can also be used to create shareholder value for outcomes, such as infrastructure deferral, that would not ordinarily be in firms' financial interest.

Several jurisdictions have implemented, or are actively considering, PBR variants that combine these mechanisms to motivate the utility to accomplish goals extending well beyond economic efficiency and service quality. A frequently cited example of a PBR approach addressing more goals than cost alone is the RIIO model developed in the United Kingdom (Ofgem, 2013). The RIIO model applies PIMs to a wide variety of new outcomes (e.g. reduced environmental impact, smooth connection of third-party service providers, or speedy connection of new customers)

[9] Price cap regulation encourages utilities to increase electricity sales in order to cover their fixed costs. For jurisdictions aiming to take advantage of energy efficiency as a resource, price caps do not align utility incentives with outcomes these jurisdictions prefer.

and also uses a benchmarked revenue cap to achieve an efficient level of overall expenditures (Mandel, 2014).

REGULATORY MODELS, SHAREHOLDER VALUE, AND UTILITY MOTIVATION

Performance-based regulatory models are meant to better align utility motivation with the outcomes customers and society desire. Companies increase shareholder value when they realize a rate of return (r) that is higher than their cost of capital (k) (Kihm et al., 2015). Under COSR, an IOU's rate of return is applied to all prudently-incurred capital expenditures. As a result, utilities are provided positive incentives to invest in capital when (r - k) is greater than zero. If (r - k) is less than zero, as was the case during much of mid to late 1970s and early 1980s, utilities are not incentivized to invest in capital (Pierce, 1984)[10]. A positive (r - k) is a key driver of the shareholder value engine[11].

In instances where expansion of infrastructure is needed, tying shareholder value to capital expansion can be valuable to society. This is particularly prudent when economies of scale dominate. However, when non-capital solutions, like a DER-based alternative to a traditional infrastructure investment, are able to provide value, capital-based rates of return may lead to misaligned utility incentives. Whether COSR can meet 21st century energy regulatory policies depends in no small degree on how capital-intensive the industry will be and what types of firms can most efficiently deploy capital as progress in technology and policy continues.

Utility regulation in the United States is adversarial in practice. Parties to proceedings present evidence in order to make the case for policy designs that support their preferred outcomes. If the preferred outcomes of utilities—or other businesses intervening in the regulatory process (e.g. shareholder value)—are not well-aligned with the preferred outcomes of organizations representing customer or environmental interests (e.g. low cost, reduced emissions), regulators must adjudicate among these groups' preferred outcomes. The regulator's adjudicatory task is complicated by both the information asymmetries they face vis-à-vis utilities, as well as by information asymmetries between utilities and intervenors (Gimon, 2016). The primary means regulators have for overcoming these asymmetries include required information filings, accounting audits, comparisons with industry standards, and comparisons of outcomes under scrutiny with broad industry metrics. Only rarely do regulators employ prudence reviews and the earnings disallowances that occasionally follow.

[10] These outcomes are known in the economics literature as the Averch-Johnson and Reverse Averch-Johnson effects (Averch and Johnson, 1962).

[11] This formulation of utility motivation is undoubtedly a simplification of how IOU managers plan. The regulatory process can be thought of as an ongoing "game" so powerful reputation incentives exist that may limit near-term profit maximization.

Changing technologies and new policy priorities create challenges for Cost of Service Regulation.

1. *Cost of Service Regulation (COSR) rewards utilities for infrastructure investments, but new technologies and grid management tools offer non-infrastructure approaches that are potentially less costly and better-aligned with outcomes society seeks.*
2. *The main tool for cost-containment is the prudence review, but regulators face substantial technical and resource asymmetries when evaluating utility expenditures.*
3. *These two features of COSR limit regulators' ability to respond to present and future industry trends and challenges.*

Regulatory models define how utilities earn their rate of return (r). Under COSR, utilities realize a rate of return by adding to their rate base and reducing operational costs between rate cases. In contrast, under a revenue cap utilities only earn a return on the net of allowed and actual revenues. Regulatory models also affect the cost of capital (k) through investor perceptions of risk.[12] New regulatory models should therefore be assessed, at least in part, on their ability to align the (r - k) "shareholder value engine" (Kihm et at., 2015) with the outcomes that matter most to society.

Accomplishing this alignment requires that regulators undertake the non-trivial tasks of identifying 1) what preferred outcomes ought to be, 2) what metrics reflect these outcomes, 3) how performance should be translated into financial rewards that provide sufficient motivation, and 4) what impacts a new revenue model has on investor perceptions of risk. A realigned shareholder value engine holds the promise of reducing impacts of information asymmetries and driving accomplishment of preferred outcomes.

2. ASSESSING THE IMPACT OF REGULATORY MODELS ON UTILITY MOTIVATION

Utilities are faced with an array of alternatives to meet system needs. Which path they prefer depends on the pathways to shareholder value that are offered under the regulatory models in which they operate. The following analysis considers three examples demonstrating clear differences in utility and customer value between project alternatives. Each example presents two to three strategies a utility could pursue to meet a grid need. These alternative approaches include 1) traditional utility investments, 2) investments where utilities own and operate assets like DERs, and 3) models where grid infrastructure services are provided by third-party-owned

[12] The cost of capital largely reflects a firm's sensitivity to macroeconomic risks. Firm-specific risks affect expectations about the rates of return the firm will earn in the future (Brealey, Myers, and Allen, 2006).

resources. These alternate strategies are compared side-by-side in terms of their impacts on shareholder value and their total cost under both COSR and a handful of different PBR models.

The examples considered in this paper stipulate that alternative investments are both more cost-effective and better aligned with societal value than conventional, infrastructure-based approaches. This assumption is not meant to suggest that conventional investments are always—or even often—sub-optimal, but instead to examine specific instances where better alternatives exist. Tracing through simple financial comparisons can show how regulatory models affect whether or not the utility derives financial value from pursuing projects that deliver societal value.

The goal of these models is to illustrate the impact of regulatory strategies on utility motivation at a high level, providing a more simplified analysis without including many nuances like deferred taxes. Similarly, dynamic effects of different regulatory models on the cost of equity (k) are beyond the scope of this report, though undoubtedly will be a central consideration as PBR moves from papers to practice. While the modelling approach used in this paper is not sufficient to inform a specific rate-setting process, case-by-case comparisons can offer a glimpse of whether changes to the utility revenue model can translate into increased alignment between shareholder and societal value.

EXAMPLE 1: A CONSTRAINED DISTRIBUTION CIRCUIT

Distribution upgrades are capital-intensive projects that all utilities must undertake on an ongoing basis. When faced with load growth on a distribution system, the conventional approach is to increase the capacity of equipment like conductors or substation transformers. However, with the emergence of low-cost DERs and more flexible grid infrastructure, non-traditional strategies to meet load growth may be more cost-effective (Neme and Grevatt, 2015). For instance, targeted energy efficiency measures or solar combined with storage can decrease net load that must be served through the distribution system (ConEd, 2015a). Further, targeted application of modern grid controls allow operators to rapidly relieve constraints by realigning circuit connections to take better advantage of available capacity in nearby segments of the distribution system (PNNL, 2015).

Utility distribution planners seek to identify solutions to grid engineering problems that meet needed performance criteria. That said, as long as (r) exceeds (k), utilities are rewarded financially when they choose more capital-intensive solutions. This example considers a case where a DER-based strategy is clearly the superior option from a cost and societal preference point of view. Under COSR, a regulator with perfect information would be expected to deem the more expensive conventional capacity upgrade project as imprudent. However, regulators typically lack the time and staff to achieve an in-depth understanding of the nuances of each component of utility distribution systems and the range of options available to enhance distribution system performance (O'Boyle, 2016). These information and analytical resource asymmetries limit regulators' ability to accurately assess which investments are prudent. Such asymmetries may be exacerbated when both the availability and cost of technologies are rapidly changing.

Project details

In this example, utility engineers have determined that load growth in a region will cause a local distribution system to exceed its capacity limits. The present capacity of the distribution infrastructure considered is 70 MW, while peak load is expected to grow to 76 MW by 2026. The current peak load is 60 MW. This load growth is assumed to be gradual enough that an infrastructure investment is not needed to solve an immediate reliability issue.

Project alternatives

Three different project types are considered in this example to meet peak load. By design, it is assumed a utility-owned DER-based solution is less expensive than a conventional upgrade, and a third-party DER procurement approach is cheaper still. This investment is analyzed in isolation, assuming no other system upgrades—for example, an increase in generation capacity—would be necessary. These assumptions may not hold in many cases, but this example is meant to illustrate how utility motivation varies in an instance where they do.

Under the first project approach—the **Conventional** strategy—the utility undertakes an infrastructure investment to increase the capacity of the local substation by 20 MW, to 90 MW. The upfront capital costs of this project are expected to be $47 million[13] over four years. The ongoing operations and maintenance costs for the project will be $250,000 per year. The new assets are assumed to have a useful life of 25 years.

An alternative approach—the **Utility-Owned DERs** strategy—is for the utility to invest in DERs in which it develops a bundle of DERs to reduce peak net demand on the distribution system by 20 MW, to 56 MW in 2026. It is stipulated that the upfront costs of DERs are 20 percent lower than that of the conventional approach, or $37 million over four years. The ongoing operations and maintenance costs for the project are assumed to be $500,000 per year, reflecting an incremental cost of operating new technologies and variable energy resources. The bundle of assets procured is assumed to have a useful life of 25 years. In short, this alternative strategy lasts the same amount of time as the Conventional approach, but has lower upfront capital costs and somewhat higher ongoing operations and maintenance costs.

The third project approach—the **Third Party DERs** strategy—is to open a procurement that allows third-party providers to compete to meet the identified grid need. This project involves the utility entering into a 10-year power purchase agreement (PPA) costing $4.4 million annually[14]

[13] These figures are based on the cost of installing a new transformer as reported by Consolidated Edison in their benefit-cost analysis of the Brooklyn Queens Demand Management Program (ConEd, 2014). More details on the cost assumption used in this example can be found in Appendix B.

[14] This figure assumes that the all in-cost for the DER provider(s) is $2.4 per Watt. That cost below present costs to install solar PV (Barbose and Darghouth, 2015). However, this scenario assumes a bundle of DER technologies (e.g.

and, like the utility-owned DER strategy, also reducing net peak demand by 20 MW, to 56 MW in 2026. While the contract payment is offered in terms of energy, the PPA requires that performance characteristics of the procured resources meet the capacity need facing the distribution system. This option assumes operational costs of $250,000 per year, which assumes some of the incremental costs of managing the assets are born by the third-party provider.

The third-party approach here is assumed to be cheaper than a utility-owned approach, but there may be cost savings or other public policy goals that utility-owned DER approaches can achieve better in other cases (O'Boyle, 2015). The purpose of this exercise is to assess how to motivate utilities to optimize their investment when relying on a third party *would* create savings compared to a utility-owned approach.

Regulatory Alternatives

The implications for total costs to consumers and creation of utility shareholder value are evaluated under four different regulatory models:

1. **COSR**: A rate of return is only allowed for capital investments and all other expenditures are treated as a pass-through.
2. **COSR or third-party ROR**: A utility may earn a rate of return on capital investments or may earn a return on DERs procured from third parties.
3. **COSR modified with a peak load reduction PIM**: The utility earns a return on capital investment, but is given a peak demand target against which it faces the prospect of both positive incentives and negative penalties.
4. **Benchmarked revenue cap, with a "stretch factor"**: A revenue cap is set at five percent less than the revenue requirement calculated for conventional COSR, and the utility shares some savings relative to the cap.

For each regulatory alternative, the total cost of the project and shareholder value created are modeled. All financial figures are calculated using a discounted cash flow analysis and presented in present value terms. Appendices A and B offer more detailed descriptions of how each regulatory alternative is modeled.

Regulatory Alternative: Cost of Service Regulation

Under COSR, utilities are only able to earn a rate of return on capital investments. It is assumed that the utility uses an even split of debt and equity financing. The cost of debt used to calculate the rate of return is six percent and the allowed return on equity (r) is 11 percent.[15] Therefore, the authorized weighted rate of return on capital in this example is assumed to be 8.5 percent.

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energy efficiency, storage) and progress towards the U.S. Department of Energy's Sunshot goal of $1 per Watt installed cost of solar PV.

[15] Allowed return on equity (ROE) varies state to state. An 11 percent ROE is likely on the high end of allowed returns on equity.

The cost of equity (k)—that is, the return required by investors—is assumed to be 7.5 percent (Kihm et al., 2015).

Throughout the course of the discussion below, the total cost and shareholder value created under COSR are used as a benchmark to compare alternative regulatory models. Total cost in this example is defined as the present value of all capital investments, returns, and operational expenses. Shareholder value is defined as the earnings remaining after interest on debt, tax liabilities, and returns required by existing equity investors are accounted for.[16] In other words, utilities create value for their shareholders when their rate of return on equity (r) exceeds their cost of capital (k).

Cost of Service Regulation (8.5 percent ROR on CAPEX)			
Alternative	**Total Cost**	**Shareholder Value**	**Peak Demand in 2026**
Conventional Strategy	$56 million	$5.2 million	76 MW
Utility-owned DER Strategy	$47.5 million	$4 million	56 MW

Table 1. Cost of Service Regulation (8.5 percent ROR on CAPEX)

Table 1 shows that, under COSR, the Conventional strategy is costlier than the Utility-Owned DER strategy. The result is that the utility maximizes its rate base and creates more shareholder value by choosing a traditional infrastructure investment. This example illustrates how COSR can lead to misaligned incentives when a non-traditional approach to a grid need is available at lower cost than a conventional upgrade.

It is tempting to posit that regulators, as stewards of the public interest, should simply order the utility to adopt the DER alternative to the detriment of utility shareholders. However, this temptation ignores the information and resource asymmetries among regulators, intervenors and utilities. This example considers an outlay of $40 to $60 million over the course of several years, a small component of annual utility distribution budgets that are typically measured in billions of dollars in any one year (SCE, 2015). Recent evidence suggests capacity savings from DERs are relatively small in most segments of the grid, but very valuable where capacity constraints do exist (Cohen et al., 2015). In the face of this heterogeneity of DER values, it may be impossible for a regulator to effectively separate prudent investments from those that are not.

In addition, it is likely that despite a better option being available, the conventional solution would meet a “used and useful” standard that guides regulators in reviewing investments for

[16] In practice, not all of these funds would go directly to shareholders in the form of stock price appreciation or dividends. A proportion of earnings would be used for other purposes, such as to reinvest in plants.

prudency (McDermott, 2012). Under that standard, a transformer would be used to facilitate growing demand, and useful in that its scale would not be excessive relative to the need. While one could argue that the existence of a cheaper alternative erodes the "usefulness" designation, information asymmetry and resource constraints mean that prudency review falls short of providing a framework for regulators to assess and propose more cost-effective alternatives.

Regulatory Alternative 1: Cost of service regulation or rate of return for DER procurements

This regulatory alternative allows the utility to either earn a rate of return on capital expenditures, or to receive a rate of return on the cost of DERs procured from third parties. The rate of return on DER expenditures is set at 3.5 percent and allowed for 10 years.[17] The DER expenditures assessed in this case are based on an upfront installed cost of about $2.70/Watt.[18] The utility pays for this procurement through a 10-year PPA.

COSR or 3.5 percent ROR for DER Expenditures			
Alternative	**Total Cost**	**Shareholder Value**	**Peak Demand in 2026**
Conventional Strategy	$56 million	$5.3 million	76 MW
Third-party DERs	$43 million	$1.1 million	56 MW

Table 2. COSR or 3.5 percent ROR for DER Expenditures

A notable feature of this regulatory alternative is it provides utilities with stable returns when they procure third-party DERs, an attempt to address the capital bias of COSR. However, allowing a rate of return on non-capital DER expenditures creates much less value for utility shareholders than investing in a conventional upgrade (Table 2). This example highlights that the size of the (r - k) gap is not the only determinant of shareholder value (Kihm et al., 2015). The amount of shareholder value created also depends on the size of the spending upon which returns are earned, and how long these returns are allowed. All else being equal, costlier and longer-lived assets upon which a rate of return is earned create more value for shareholders. Given the size of the DER investment and span of allowed returns, the rate of return for the DER alternative in this example would have to be set at more than 20 percent for shareholder value to equal that created under the Conventional approach.

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[17] In a recent ruling, CPUC Commissioner Florio proposed a similar pilot relying on utilities to identify areas where DERs can defer distribution investments in exchange for a percentage return on the DER investment (California Public Utilities Commission, 2016). "Assigned Commissioner's Ruling Introducing a Draft Regulatory Incentives Proposal for Discussion and Comment. (R. 14-10-003)." While this order also uses 3.5 percent as the rate of return for DER investments, this case study contains assumptions that are not a part of the CPUC order.

[18] This estimate is explained in Appendix B. It is an average of BQDM cost estimation of $3.8/W and a blended average of energy efficiency, demand response, and residential rooftop solar costs, resulting in an average DER cost of $1.55/W.

This regulatory model also does not address information and resource asymmetries. Under the assumptions included above, the utility is heavily incented to pursue the Conventional strategy, even though customers clearly benefit from the DER-based approach. Furthermore, applying a rate of return to DER alternatives provides utilities with an incentive to procure costlier portfolios of DERs. A goal of procurement-based approaches is to encourage the utility to competitively source the least-cost, highest-value solution to a grid need. If a utility's incentives in this procurement process are misaligned with customer value, regulators will need to fall back on prudence reviews as their primary strategy to avoid unnecessary expenses.

Regulatory Alternative 2: Cost of Service with PIMs

The next regulatory alternative maintains cost of service regulation under the same assumptions, but adds a PIM that offers the utility both an upside and downside vis-à-vis a peak demand target of 70 MW, the point at which the system requires increased capacity.[19] The PIM is designed so the utility earns $200,000 per MW reduced below the peak demand benchmark.[20] The utility also faces a $200,000 penalty per MW peak demand that exceeds the benchmark. Both DER alternatives are assumed to reduce peak demand to 56 MW in 2026.

COSR + PIMs (8.5 percent ROR, symmetrical incentive/penalty $200k per MW)			
Alternative	**Total Cost**	**Shareholder Value**	**Peak Demand in 2026**
Conventional Strategy	$56 million	$4.8 million	76 MW
Utility-owned DER Strategy	$50 million	$5.5 million	56 MW
Third-party DER (with 3.5% utility ROR on DER)	$45 million	$2.5 million	56 MW

Table 3. COSR + PIMs (8.5 percent, symmetrical incentive/penalty $200 per MW)

Applying a PIM in this case better aligns utility incentives with customer value compared to COSR (Table 3). Shareholders earn additional value from the DER approach because their returns under COSR are supplemented by PIM payments. Although a share of the value created by the

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[19] As mentioned above, a utility regulator faces substantial information asymmetries relative to utilities with regard to the technical needs of the grid and the solutions to meet them. This means that a circuit by circuit peak demand PIM would be challenging to implement, even though peak reduction value varies based on the level of congestion in each circuit. In this case, it is most useful to think of this PIM as part of a larger system-wide peak demand reduction strategy, which tends to yield consistent benefits in aggregate.

[20] This figure is based on a recent estimate that the avoided distribution costs of DERs are $350,000 per MW peak reduced (Advanced Energy Economy, 2015). A PIM set at $200,000 per MW therefore shares the benefits and costs of utility performance against a peak demand goal between the firm and customers. Other models for PIMs include shared savings and basis point adjustments to ROR; a thorough discussion comparing each approach can be found in Whited and Woolf (2015).

DER alternative is given to utilities, customers continue to receive substantial additional value compared to the outcome under a Conventional strategy due to lower overall costs.

Whether the utility owns the project will affect the utility value proposition under a PIM + COSR framework. Adding the same PIM to the third-party DER solution above, wherein the utility gets a 3.5 percent return on DER expenditures, would create less shareholder value in this case than the utility-owned DER solution. This lower return comes despite an additional $5 million in savings for customers. Under these assumptions, PIM + COSR still creates an incentive to pursue a utility-owned solution even if a more optimal solution exists from a societal perspective. The third-party solution is better aligned with utility shareholder value than the same approach without the PIM, but it is still less attractive than increasing the rate base. The example shows that PIMs operate within a larger revenue and value structure that complicates the ultimate goal of motivating the development of the most efficient system possible.

This regulatory alternative has a positive impact on information and resource asymmetries. The utility has a clear incentive to find peak reductions that save customers money. However, whether the utility makes this decision may depend on the degree to which their decision-making is biased towards business-as-usual approaches. A new strategy to meet grid needs could be perceived as risky to both utility shareholders and employees. Or, in some cases, the utility may not have the information necessary to discern a viable DER alternative.

Unless shareholders' gains from spending managerial effort on the DER alternative are sufficient to overcome these risks, utilities may default to conventional strategies. In this example, it is not clear that the incremental benefit of $0.7 million in shareholder value from a DER-based project would sufficiently motivate a utility that may prefer the more familiar Conventional strategy. Furthermore, reductions in peak demand may lead to reductions in needed capacity investments beyond those accounted for in this example. If that were the case, the utilities' rate of return on capital investments would decline, and so too would the value created for shareholders.

Regulatory Alternative 3: Revenue cap benchmarked with a "Stretch Factor"

In this case, the utility operates under a revenue cap five percent below the revenue requirement used in the COSR alternative. The stretch factor[21] that reduces the revenue cap is applied to encourage the utility to identify less costly strategies to deliver service, and to reveal these approaches to regulators.[22] The revenue cap is applied over an eight-year, multi-year rate plan. Within the MYRP, all cost savings and overruns are shared 70/30 between the utility and consumers, respectively. At the end of the eight-year MYRP, all remaining cost savings or overruns are accounted for as a reduction or addition to the following period's revenue cap.

[21] Stretch factors account for the effects of historic regulation and/or anticipated changes in industry conditions. In this example, the stretch factor is 0.95.

[22] An additional tool that regulators can use in revenue cap regulation is an 'X-factor.' X-factors reduce annual revenues (or the rate of revenue increase) by some percentage each year that is meant to reflect overall productivity gains in the economy or cost reductions in the inputs used by the utility (Comnes 1995).

An actual revenue cap would be applied to all, or very large share, of a utility's operations. The cap in this example can be best interpreted as the share of the overall revenue a utility could dedicate to distribution upgrade projects of this scale, given the firm's other financial commitments. While highly stylized, this approach illustrates how a benchmarked revenue cap can motivate utilities to pursue more valuable investments from a societal perspective.

Revenue cap with a stretch factor			
Alternative	Total Cost	Shareholder Value	Peak Demand in 2026
Conventional Strategy	$55 million	($0.7 million)	76 MW
Utility-owned DER Strategy	$53 million	$2.3 million	56 MW
Third-party DERs	$39 million	$6.7 million	56 MW

Table 4. Revenue cap with a stretch factor

Among the regulatory alternatives considered in this example, a revenue cap creates the starkest distinction between shareholder value created in the Conventional versus the DER-based alternatives (Table 4). Both customers and utility shareholders benefit when either the utility-owned or third-party DER strategies are pursued. In fact, the Conventional strategy destroys shareholder value because it exceeds the stretch factor that accompanies the benchmark. Even the Conventional strategy costs less in this example because utility earnings after the end of the MYRP are returned to customers via a downward adjustment in the next period's revenue cap.

The DER solutions are most attractive because the utility is able to make incremental DER acquisitions to meet ongoing needs, rather than a large upfront capital expense to meet future peak demand as modeled in the revenue cap. These savings are particularly valuable in early years, when only small expenditures are needed to procure the incremental DERs necessary to reduce peak demand and maintain reliable service. The third-party DER alternative saves customers about $16 million while maximizing utility shareholder value, creating substantial alignment between utility motivation and societal value.

Distribution Capacity - Analysis of Alternatives

The purpose of this case is to illustrate an instance where COSR motivates utilities to pursue a conventional grid upgrade, while benefits to society are higher under a less capital-intensive alternative. The preferred outcomes of this example from a societal perspective are, by design, the DER alternatives. Were the DER alternative more expensive, the conventional solution would be the most attractive case, indicating alignment between customer and shareholder value. As the discussion above illustrates, the value of each alternative to utility shareholders, and thus the solution advocated by the utility, varies substantially based on the regulatory model applied (1). But assuming, among other things, that latent value exists by taking advantage of third-party DERs for grid services, a benchmarked revenue cap applied over an eight-year MYRP aligns shareholder and customer value.

Figure 1. Distribution upgrade: Total cost, shareholder value, and savings compared to business-as-usual[23]

> *Example 1 Winner: Benchmarked revenue cap*
>
> *In reality, there will be instances where a grid need can only be met by a more expensive approach or where a conventional infrastructure upgrade is the most cost-effective strategy. A well designed system-wide revenue cap should therefore sufficiently motivate utilities to pursue lower-cost DER alternatives when available, while also allowing utilities to invest in conventional upgrades when they are the most valuable option to society. Considerations for how such a revenue cap could be designed are discussed in Section 3.*

EXAMPLE 2: UTILITY VERSUS THIRD-PARTY GRID MODERNIZATION INFRASTRUCTURE AND OPERATIONS

Grid modernization investments enable utilities, third-party service providers, and customers to both better understand grid challenges and to facilitate new services to cost-effectively meet needs that are identified. For large utilities, smart grid infrastructure investments can cost billions of dollars (ConEd, 2015).[24] In a time where many utilities are experiencing stagnant load growth, these infrastructure investments are attractive opportunities to increase the rate base and create shareholder value.

Not all segments of a grid modernization program need to be owned and operated by utilities. Third-party firms may be better positioned to deliver the performance society seeks from new grid infrastructure at lower costs. Standards like Smart Energy Profile 2.0 create opportunities

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[23] Notes: 1) Total cost and shareholder value figures are from Tables 1 through 4. 2) Savings Compared to BAU is the difference between the cost of the Conventional solution under COSR regulation (the top row) and each alternative.

[24] For example, Illinois' Energy Infrastructure Modernization Act approved $2.6 billion in spending on grid modernization investment for its largest utility, Commonweath Edison. 220 Ill. Comp. Stat. § 5/16-108.5.

for third parties to securely interact with smart grid infrastructure (IEEE, 2013). The nature of these interactions can range from activation of demand response resources in a home to communication of meter data via Wi-Fi networks.

Under COSR, shareholders lose value when a third party provides services that a utility could have provided itself through a capital expenditure that increases the rate base. Utilities are therefore incented to push for ownership of all smart grid infrastructure, regardless of whether owning these assets is the most cost-effective option. This incentive may not only create cost inefficiencies, but could also lead the utility to foreclose competition in new energy services markets that are enabled by grid modernization.

Project Details

In this example, a utility is proposing to undertake a system-wide grid modernization investment. The major categories of expenditure are the service meters, communications infrastructure, back-end information technology capacity, and increased staff capacity to manage the new system. This grid modernization build-out involves both substantial capital investments on which the utility creates shareholder value, as well as substantial operational expenses (Table 5).

Grid Modernization Investment Costs for Example Utility			
Cost Category	*Capital*	*Operational*	*Total*
Meters	\$590 million	\$0	\$590 million
Communications	\$80 million	\$260 million	\$340 million
Information Technology	\$230 million	\$490 million	\$720 million
Project management	\$120 million	\$140 million	\$260 million
Totals	*\$1,020 million*	*\$890 million*	*\$1,910 million*

Table 5. Grid modernization investment costs for example utility

Notes: figures derived from figures in Consolidated Edison's 2015 smart grid build-out proposal (ConEd, 2015b).[25]

[25] In this case, the modeled utility is assumed to have 2.7 million customers, 700,000 fewer than ConEd's 3.4 million customers. Numbers are scaled down to reflect this difference.

Project Alternatives

The first approach, the **Conventional** strategy, proceeds with a grid modernization program that is owned and operated entirely by utilities.

An alternative approach allows third parties to compete to provide a subset of smart grid services. In this case, it is assumed that the 'Communications' category of expenses can be met through a **Procurement**-based approach. Instead of a utility building new infrastructure and operational capability to transmit advanced meter data, third parties could use standards like SEP 2.0 to handle data backhaul via customers' existing internet connectivity. In this case it is assumed that a third-party provider could provide all necessary communications functions to the utility for $2 per customer per month, a substantial capital and operational savings from the conventional strategy.

Regulatory Alternatives

The customer and shareholder value impacts of the two project alternatives are considered under three different regulatory models:

1. **COSR**: The utility earns a return on capital investments, and operational expenses are treated as a pass-through.
2. **Revenue cap**: The revenue cap is based on the revenue requirement under COSR.
3. **Revenue cap with a stretch factor**: The revenue cap is based on the revenue requirement under COSR, but is reduced via a stretch factor.

The total cost of the project and shareholder value are modeled for each regulatory alternative. All financial figures are calculated using a discounted cash flow analysis and presented in terms of present value.

Regulatory Alternative 1: Cost of Service Regulation

Under COSR, utilities are only able to earn a rate of return on capital investments. It is assumed that the utility uses an even split of debt and equity financing. The cost of debt used to calculate the rate of return is six percent, and the allowed return on equity (r) is 11 percent[26]. Therefore, the allowed rate of return on capital in this example is assumed to be 8.5 percent. The cost of equity (k)—that is, the return required by investors—is assumed to be 7.5 percent (Kihm et al., 2015).

[26] Allowed ROE varies state to state. An 11% ROE is likely on the high end of allowed returns on equity.

Cost of Service (8.5 percent ROR on CAPEX)		
Alternative	**Total Cost**	**Shareholder Value**
Conventional Strategy	$1,910 million	$130 million
Third-party Provider	$1,630 million	$120 million

Table 6. Cost of service (8.5 percent ROR on CAPEX)

Under COSR, the utility creates well over $100 million in shareholder value under either option, as capital expenditures remain the majority of the cost of grid modernization. The firm's earnings are slightly higher when pursuing the utility owned strategy, but the difference in value creation ($10 million) is small relative to the size of the project. In contrast, the operational cost savings realized under the third-party provider procurement approach create substantial value for customers. Since operational costs are a pass-through in this regulatory model, the utility is indifferent to these cost savings and will still prefer the Conventional strategy, though it is only marginally more attractive.

Regulatory Alternative 2: Revenue cap set at cost of service

This regulatory approach establishes a five-year MYRP, where the revenue cap is set at the costs used in the COSR case. Seventy percent of any cost overruns or savings during the MYRP are retained by the utility, with the remaining 30 percent accruing to customers. After five years, it is assumed the next MYRP revenue cap is reset at the lower realized cost level. The implication is all savings relative to COSR six years out and beyond accrue to customers.

Revenue cap set at cost of service		
Alternative	**Total Cost**	**Shareholder Value**
Conventional Strategy	$1,760 million	$4 million
Third-party Provider	$1,620 million	$60 million

Table 7. Revenue cap set at cost of service

A MYRP with a revenue cap creates a clear distinction between earnings under the utility-owned versus third-party project alternatives than COSR. Instead of earnings based on an allowed rate of return, shareholder value is created when the utility can identify approaches to provide lower cost services than those included in the benchmark. In this case, the third-party solution is clearly less expensive, thus creating $140 million in additional savings compared to a utility-owned approach under COSR, despite an approximately $60 million increase in net compensation for the utility. This outcome largely stems from substantial savings in the operational costs of communicating and analyzing grid data.

An important feature of revenue caps is highlighted in this example: They are able to provide utilities with an upside in identifying and capturing savings in operational costs. Operational savings are not encouraged under COSR with frequent rate cases, whereas operational solutions that create efficiencies or replace capital expenditures are encouraged under a revenue cap.

Regulatory Alternative 3: Benchmarked Revenue Cap with a Stretch Factor

While the previous regulatory alternative illustrates the ability of a revenue cap to motivate utilities to identify and secure cost savings, there still may be little downside for a utility to pursue a conventional approach if the cap is set equal to the conventional estimate. To stimulate more efficient behavior and motivate cost savings, regulators could consider applying a "stretch factor" to reduce the revenue cap a utility faces. In this case, a stretch factor is applied to reduce the overall revenue requirement by five percent relative to that allowed under COSR, simulating improvements in efficiency.

Revenue cap with stretch factor		
Alternative	Total Cost	Shareholder Value
Conventional Strategy	$1,720 million	($20 million)
Third Party Provider	$1,570 million	$40 million

Table 8. Revenue cap with stretch factor

Applying a stretch factor reduces shareholder earnings to levels below those of COSR and clearly disincents the firm from pursuing a wholly utility-owned smart grid deployment strategy. Only by procuring communications services from a third party does advanced metering infrastructure (AMI) investment benefit the utility financially. Of course, grid modernization does not occur in isolation, or with only one possibility for operational savings. Utilities facing a stretched revenue cap with a long-term investment portfolio and MYRP have opportunities and incentives to find other savings that can create more value for their shareholders (e.g. SolarCity, 2016).

Grid Modernization Investment - Analysis of Alternatives

This example illustrates an instance where substantial operational savings are available, but a utility has little to no incentive to capture this value under COSR with frequent rate cases. In contrast, a utility under a revenue cap is motivated to identify operational efficiencies that create shareholder value. Critically, a revenue cap that is applied across both capital and operational expenses encourages a utility to identify and achieve an efficient mix of inputs. In contrast, a MYRP that only encourages operational cost reductions between rate cases exacerbates utilities' preference for capital-based solutions.

It is worth noting that the savings here are realistic, but likely do not represent the full range of options for taking advantage of third-party services for grid modernization. To a large extent, this potential is unproven and untapped. SolarCity de-rated the investments earmarked for "distributed energy resource integration" in Southern California Edison's distributed resource plan by nearly 75 percent, asserting distributed energy resources could provide those services at a fraction of the cost, or otherwise are not necessary (SolarCity, 2016). That equated to $4 billion in avoided capital and operational expenditures. While it is far beyond the scope of this paper to validate those numbers, that is one data point indicating there is room for debate about the extent to which third parties can provide savings under grid modernization plans.

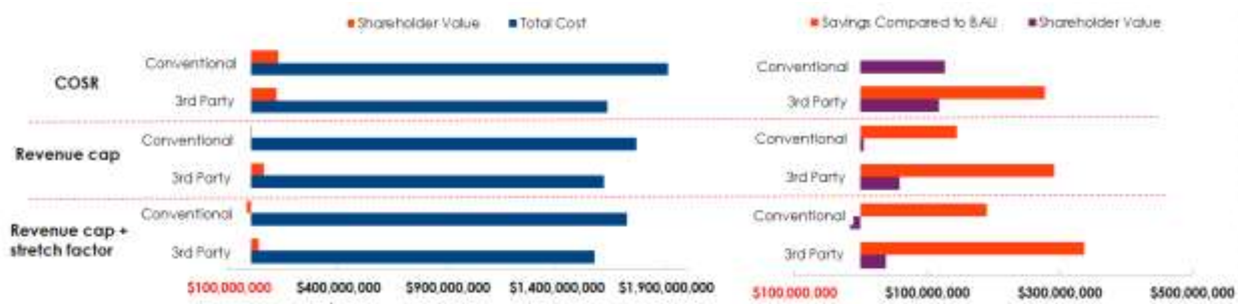

Figure 2. Grid modernization: Total cost, shareholder value, and savings compared to business-as-usual[27]

Example 2 Winner: Benchmarked Revenue cap with Stretch Factor *This revenue model may not only better align utility motivation and customer value, but could also incent the utility to support the development of multi-use, adaptable grid modernization frameworks. Multi-use networks enable a variety of connected devices to receive grid signals and unlock additional value of future technological innovations (Radgowski, 2015). Supporting this functionality would be consistent with a future where a utility creates value by fulfilling a "platform" function, facilitating third-party competition in segments of the industry that have traditionally be considered to have natural monopoly characteristics.*

[27] *Notes: 1) Total cost and shareholder value figures are from Tables 1 through 4. 2) Savings Compared to BAU is the difference between the cost of the Conventional solution under COSR regulation (the top row) and each alternative.*

EXAMPLE 3: REGIONAL RELIABILITY NEED AND ENVIRONMENTAL PERFORMANCE

In many jurisdictions, investor-owned utilities no longer own generation. Instead, IOUs procure energy on behalf of their customers through a combination of wholesale market transactions and long-term contracts. While real-time and day-ahead energy markets exist, many jurisdictions rely on long-term contracts to ensure supply is sufficient to meet demand at all locations and times.

A common financial arrangement for long-term contracts is a tolling agreement, where a third party finances and develops a power plant, but the utility has operational control over the facility (Skinner, 2010). Tolling agreements typically include a 20-year (or longer) commitment for the utility to pay the project developer a capacity charge, as well as a price per unit of energy produced. The utility is then responsible to pay separately for all fuel needed to run the plant.

Regardless of utility structure, most jurisdictions use fuel adjustment clauses (FACs) to reimburse the fuel costs a utility incurs in operating a power plant, passing through the cost directly to customers. The rationale is that utilities are price-takers for fuels—the utility has little or no ability to affect their price (Graves et al., 2006). Under the FAC, the utility bears no risk of fuel price volatility or many of the other externalities associated with fossil fuel generation—FACs pass the risk of fuel price variation from utilities onto consumers.

A utility *does* have a choice in deciding what sorts of generation it relies on when planning to meet a grid need. However, with no skin in the game, utilities' main incentive is to rely on well understood conventional solutions to meet grid needs. The following cases investigate whether utilities that retain some portion of environmental and fuel price risks might choose to contract with resources better aligned with societal value.

Project Details

A distribution and retail utility has identified a looming capacity shortfall of 700 MW in a specific region of their network in which an existing plant will soon retire. The conventional approach to address such a problem is to sign a long-term power purchase agreement (PPA) with an independent project developer using a tolling agreement. To evaluate the likely rate impacts of this agreement, regulators develop a 20-year projection of natural gas prices. Gas prices are notoriously variable, so projections based on history are likely to be wrong, with the potential for large fluctuations in project cost. This example stipulates the utility's price projections will systematically underestimate the cost of natural gas over the timespan of the project in question. Details on fuel cost projections used in this example can be found Appendix B.

In addition, this generator is in a jurisdiction with ambitious greenhouse gas emissions mitigation goals. Policymakers intend to reduce greenhouse gas emissions to 80 percent below 1990 levels by 2050. As a result, the impacts of long-term contracts for fossil fuel-based plants bear scrutiny from utility stakeholders.

Project Alternatives

Two different projects have been proposed to address this grid need. The first involves entering into a long-term PPA with a 700 MW natural gas power plant to meet the grid need. The plant is assumed to provide both 'baseload' and peaking power. The second involves investing in distributed and utility-scale clean energy resources to meet baseload power and signing a PPA with a smaller 300 MW natural gas power plant to provide only peaking power.

In this example, the utility has proposed to enter into a **Conventional** long-term contract with an independent natural gas plant. The plant will be used and useful because of its ability to meet local demand with its baseload generation and quickly ramp to support variable resources at both the local and bulk system levels.

A **Clean Energy Alternative** approach would release a request for offers to competitively procure the needed resources. In this case, it is assumed that 300 MW of the necessary capacity would be provided via a smaller gas-fired peaker plant, and the remaining energy is provided by a combination of locally-sourced DERs and wholesale purchases of bulk clean energy resources. The energy cost of DERs is assumed to be $50/MWh.[28]

Details of the physical and financial characteristics of these two alternatives can be found in Appendix B.

Regulatory Alternatives

The implications for the total cost to consumers and society and creation of shareholder value are evaluated under four different regulatory models:

1. **Conventional regulation**: The utility passes all costs, including fuel, on to consumers.
2. **Conventional regulation with a CO_2 PIM**: All procurement and fuel costs are a pass-through, but a PIM based on CO_2 per MWh emissions is applied.
3. **Conventional regulation with a fuel cost PIM**: The utility continues to pass most costs on, but a fuel-cost PIM is applied that exposes the utility to a portion of fuel price risk.
4. **Benchmarked revenue cap**: All costs of the project are included under a revenue cap.

For each regulatory alternative, the total cost of the project and shareholder value via the (r - k) relationship are modeled to determine shareholder value. All financial figures are calculated using a discounted cash flow analysis and presented in terms of present value. More detailed descriptions of how each regulatory alternative is modeled can be found in Appendix A.

[28] This figure reflects the levelized cost of energy (LCOE) for both wind and solar PV as presented in Lazard (2015). A low end of the LCOE ranges offered in that analysis are used to account for continued technological change and use of less costly energy efficiency.

Regulatory Alternative 1: Conventional Regulation

Under this regulatory model, the utility is allowed to pass all capacity, energy, and fuel costs from their procurements to consumers via annual rate adjustments. Since all procurement-related costs are passed through in rates, the tolling agreement does not create shareholder value via a rate of return. However, by placing exposure to fuel cost fluctuations entirely on consumers, fuel cost pass-throughs reduce shareholder risk.

FACs have become standard practice in utility regulation on the basis that reduced shareholder risk ultimately benefits consumers through a lower cost of capital (Graves, 2006). FACs were initially implemented in the 1970s and 1980s, when inflation and exogenous shocks led to substantial variation in fuel prices. During that period, clean energy was not a major public policy priority (Hirsch, 1999), nor was the cost of clean energy sufficient for technologies like wind and solar to serve as a viable hedge against fuel costs. Today, however, many jurisdictions prioritize development of clean energy resources: Wind and solar beat fossil fuels on price in many places (Binz and Lehr, 2015), and U.S. states like Colorado are actively pursuing their deployment to hedge against natural gas price increases (Huber, 2012).

Reduced fuel price risk is not the only reason a conventional approach creates shareholder value. In order to transmit power from central power plants to consumers, additional investments to increase distribution system capacity may be required. In contrast, an approach that includes DERs may decrease the capacity needs of the distribution system.[29] For this regulatory model, and the alternatives that follow, it is assumed that DER investments avoid distribution infrastructure investments $16,000 per MW per year (AEE 2015; Cohen et al., 2015), which comes out of the utility's rate base.[30]

[29] This is a balancing act with respect to DERs, however, since very high shares of distributed generation may create local reliability concerns that necessitate additional investment in distribution infrastructure or storage. It is worth noting that, of all U.S. states, only Hawaii has run into these problems, with over 15 percent of their capacity provided by rooftop solar. Gridco Systems Press Release, Feb. 1, 2016. "Hawaiian Electric Deploys Gridco Systems Technology to Help Increase PV Hosting Capacity of Distribution Grid Leverage Installed Asset Base." https://www.hawaiianelectric.com/Documents/about_us/news/2016/20160201_gridco_systems_technology_may_help_hawaiian_electric.pdf.

[30] This figure represents the avoided cost of distribution investment from targeted demand response. This value will vary based on the type, time and location of DERs deployed. For instance, Cohen et al. (2015) find the avoided distribution costs from distributed PV range from near $0 to $ 62,000 per MW-year depending on location, with the mean value being $6,000. A host of other technologies exist for which a similar range avoided costs are not readily available (e.g. energy efficiency, energy storage), so we adopt the average between the Cohen estimate and the AEE estimate for demand response as a reasonable central estimate.

Traditional Automatic Adjustment Clause		
Alternative	Total Cost	Shareholder Value
Conventional Strategy	$2,890 million[31]	$0
Clean Alternative	$2,150 million	($2 million)

Table 9. Traditional automatic adjustment clause

With the assumptions included in this example, customers clearly benefit from the clean alternative compared to a conventional approach. Though small relative to the scale of investment in generation, utility shareholders lose value as the clean energy alternative defers distribution grid investments.[32] Even though large savings are available, the utility would be unlikely to identify or implement cost-saving solutions to meet the local reliability need under COSR.

It may also be the case that utility planners and grid operators view the clean alternative as riskier in terms of reliability performance than a relatively well understood generation-based strategy, making the conventional approach even more attractive. Under a tolling agreement, a utility is able to control the operation of the facility to meet grid needs. Similar services may be achievable using a combination of a smaller power plant and DERs, but such approaches do not have the same decades-long track record as the conventional strategy. The result is that utility is likely to choose the conventional strategy under this regulatory model.

Regulatory Alternative 2: CO_2 Performance Standard PIM

Regulators in an economy with no carbon price, or one that is insufficient to motivate decarbonization, could assign an emissions performance standard for the electricity sector. In this regulatory model, utilities are required to procure energy that meets a portfolio-wide standard of 0.317 metric tons (MT) of CO_2 per MWh starting in 2016. This standard decreases in straight-line to 0.178 $MTCO_2$ per MWh in 2030, following the approach laid out in Orvis et al. (2015).

Utilities are offered a symmetrical PIM where the incentive and penalties are based on deviations from this standard. The PIM is set at $10 per MT CO_2 avoided over the eight-year compliance period. To facilitate harmonization with Regulatory Alternative 4 below, the utility receives its PIM reward or penalty at the end of the compliance period.

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[31] This figure includes the full costs of a natural gas power plant over 25 years, including both upfront construction and ongoing operational costs. Details on how this figure was calculated can be found in Appendix B.

[32] The reader will note that these capacity savings are quite similar to the previous example, despite involving a much larger amount of DER capacity. It is worth recalling that the distribution capacity of DERs across a grid varies substantially by location (Cohen et al 2015). In many locations, DERs provide virtually no capacity value, while in others this value is substantial. The first example in this paper is an illustration of the latter case.

For simplicity's sake, it is also assumed the all other power supplied (10,000 GWh) by the utility will exactly meet the performance standard. Any deviations from the standard are therefore attributed to the decision considered in this case. The shareholder value figures reflect the payments or penalties applied as emissions deviate from the cap. Since PIM payments are collected from ratepayers, bonuses are paid via increased consumer rates and penalties are rebated back to consumers.

CO_2 per MWh Target for Entire Energy Supply			
Alternative	**Total Cost**	**Shareholder Value**	**System emissions rate in 2030**
Conventional Strategy	$2,870 million	($22 million)	0.234 $MTCO_2$/MWh
Clean Alternative	$2,180 million	$19 million	0.146 $MTCO_2$/MWh

Table 10. CO_2 per MWh target for entire energy supply

The CO_2 per MWh PIM applied in this case creates symmetrical motivation for the utility to choose the lower emissions clean energy alternative. In this instance, that strategy also happens to be less expensive, providing a large bonus to customers. While it may seem small relative to the size of the projects, a difference of $20 million in direct shareholder benefits remains highly motivating. If regulators want to improve utility responsiveness, they could adjust the $10 per MT CO_2 value of the incentive upward or downward.

In addition, the net present value formula discounts a future benefit: The PIMs collected in 2022 and 2030 in this case are between $10-20 million each, but only amount to $7 million in today's dollars. The ability to immediately capture $7 million in relative shareholder value allows the utility to reinvest that capital assuming future returns.

Regulatory Alternative 3: Fuel Cost PIM

In this case, the utility and regulator jointly develop a projection of expected fuel prices over the course of the contract. Any deviations from that index are shared between utilities and consumers at a rate of 50 percent. If prices are higher than projections, the utility's earnings will fall. Conversely, the utility receives increased earnings when fuel prices are lower than the index. In this case, the regulator and utility agreed on a projection that natural gas prices will increase gradually over the life of the project. The actual fuel prices are assumed to be consistently above this forecast. Details on the natural gas prices used in this analysis can be found in Appendix B.

In both cases, shareholders lose value when natural gas prices exceed projections. However, shareholders are exposed to much more risk from fuel cost overruns under the conventional approach because more fuel is needed in that case. The alternative approach uses a smaller power plant and clean energy resources that require no natural gas, so the utility benefits as these technologies limit the company's—and consumers'—exposure to fuel price fluctuations.

Modified Fuel Adjustment Clause			
Alternative	**Total Cost**	**Shareholder Value**	**Fuel Cost Overrun**
Conventional Strategy	\$2,810 million	(\$80 million)	(\$247 million)
Clean Alternative	\$2,310 million	(\$12 million)	(\$33 million)

Table 11. Modified fuel adjustment clause

This example assumes natural gas prices systematically exceed projections. The opposite case must also be taken into account when considering fuel adjustment clause modifications. If natural gas prices fall below projections, then the signs in the shareholder value column will be reversed. One strategy a utility could undertake to manage its risk under this model, apart from clean energy investments, is to shade fuel price forecasts upwards. Guards against gaming would be necessary under this construct. But, assuming good faith, this PIM would create shareholder value when lower gas prices are realized.

At the same time, a high forecast of natural gas prices will increase the cost-effectiveness of clean energy alternatives, in all likelihood leading the utility to select more renewable energy and energy efficiency investment. Furthermore, if gas prices are higher than forecasted, the utility can correct its course by reducing its use of the natural gas plant in favor of cleaner sources over the course of the contract. So long as more clean energy remains a public policy priority it is not clear that shading gas prices upwards will by itself lead to negative outcomes.

That said, there does not appear to be a clear economic basis for why fuel savings are the most effective way to reward utilities for accounting for deploying more clean energy. Policymakers should consider tying revenue directly to outcomes such as carbon intensity, rather than means to outcomes such as fuel use that may distort utility focus and limit utility flexibility and innovation to deliver value (Orvis et al., 2016).

Regulatory Alternative 4: Benchmarked Revenue Cap + CO_2 per MWh PIM

In this case, all costs associated with meeting the local capacity requirement are placed under a revenue cap and an eight-year MYRP. The revenue cap is set at five percent below the cost of a conventional solution in each year. All cost savings or overruns during the MYRP are shared 50/50 between consumers and the utility for eight years, as well as a symmetrical PIM for carbon intensity that rewards shareholders \$20 per MT of CO_2 reduction, retaining some of the benefits for customers. After the MYRP period ends, all remaining costs are included in the following period's revenue cap.

Benchmarked revenue cap + CO_2 per MWh PIM			
Alternative	**Total Cost**	**Shareholder Value**	**System emissions rate in 2030**
Conventional Strategy	$2,900 million	($33 million)	0.234 $MTCO_2/MWh$
Clean Alternative	$2,090 million	$45 million	0.146 $MTCO_2/MWh$

Table 12. Benchmarked revenue cap + CO_2 per MWh PIM

A revenue cap in this instance creates a clear distinction between shareholder value destruction under the conventional solution versus shareholder value creation when the clean alternative is implemented. However, given the scale of investment required in this example, it may be unrealistic to expect a regulator to be able to set a cap that so perfectly aligns utility incentives with the public interest. Adding the CO_2 per MWh PIM supplements this margin for error and ensures that the variation in fuel price alone does not drive utility investment decisions.[33] By sharing the environmental and cost-saving benefits of a clean alternative between society and the utility shareholders, this revenue model creates alignment between shareholder value and societal goals of both affordability and environmental performance.

Given that many jurisdictions have a preference for clean energy resources (e.g. the "loading order" [California Energy Commission, 2004]), a non-PIM strategy could be to set a revenue cap based on a relatively high estimate of the clean energy alternative, rather than based on the cost of the "default" natural gas plant. A utility that faces a local capacity requirement would then need to assess returns from contracting with a fossil power plant versus the likely returns if the cost of clean resources is less than the assumptions used in setting the cap.

Local Capacity Requirement - Analysis of Alternatives

A restructured utility under traditional COSR that cannot add generation assets to the rate base receives no more direct benefit from selecting a conventional approach than it does from a more innovative, cleaner strategy. That said, the utility may nevertheless prefer a conventional solution under COSR. Utilities and grid operators are more familiar with a system that has higher shares of conventional generation, and may be much more comfortable with the properties of a large gas plant as opposed to an aggregation of distributed and centralized variable energy

[33] Similar to the regulatory alternative that implements a fuel cost PIM, both customer and shareholder value in this example are sensitive to variations in natural gas fuel prices over time. Unlike the fuel-cost PIM, the impact of fuel cost fluctuations in later years, which are more difficult to predict, are treated as a pass-through, reducing the size of potential profits or losses if natural gas prices diverge from expectations.

resources. Additionally, the familiarity of the conventional approach might appeal to firms who are only exposed to downside risk (e.g. sanctions or bad press) should they fail to deliver reliable service.

It is also important to consider the impacts of the two alternatives on segments of the utility's business where shareholder value is created. A DER-based strategy may, on net, reduce infrastructure needs in the distribution system, reducing a utility's opportunity to create shareholder value under COSR. Even when neutral on generation options, the utility may still prefer the option that justifies gold-plating the distribution system.

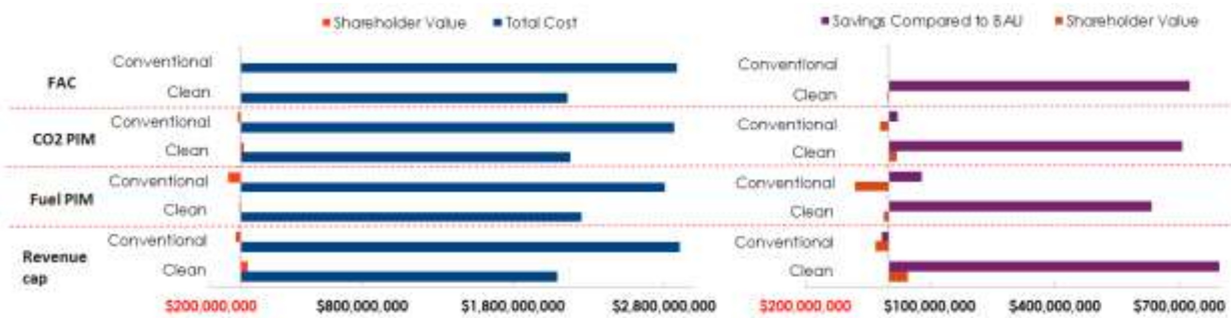

Figure 3. Capacity requirement: total cost, shareholder value, and savings compared to business as usual[34]

Example 3 Winners: ***CO_2 per MWh PIM and Benchmarked Revenue cap***

Among the regulatory options considered, a CO_2 emissions intensity PIM combined with the revenue cap most clearly aligns utility and societal value. Between these two approaches, the CO_2 per MWh PIM amplifies the alignment between utility shareholders and policy goals of affordability and environmental performance. However, the desirability of the PIM depends on the degree to which a jurisdiction does, or could, implement policies outside the utility regulatory process that price emissions either directly or indirectly. For example, a jurisdiction with a carbon price should not double-reward utility emissions reductions via a PIM along with credits earned or savings achieved.

In addition, regulators will want to account for the effects of complementary policies like energy efficiency or renewable energy standards. A compensation level of \$10 per $MTCO_2$ every eight years for the PIM yielded positive results for utility motivation without paying too much for carbon reductions. However, the task of this paper was not to recommend one compensation level over another. Regulators ultimately can use similar modeling to set the PIM to reflect the regulators' preference for assessing and allocating benefits to customers as well as impacts on utility motivation.

[34] *Notes: 1) Total cost and shareholder value figures are from Tables 1 through 4. 2) Savings Compared to BAU is the difference between the cost of the Conventional solution under COSR regulation (the top row) and each alternative*

3. REORIENTING THE SHAREHOLDER VALUE ENGINE: LESSONS AND RECOMMENDATIONS

Investor-owned utilities ultimately have a responsibility to create value for their shareholders. Shareholder value is created when utilities earn a return on equity (r) that is higher than their cost of capital (k). This paper applies the (r - k) "shareholder value engine" framework to assess how different regulatory models align utility motivation with preferred outcomes. The three cases considered are meant to be representative of instances where customers are clearly better off under an alternative strategy, but utility shareholder value is maximized when a conventional grid upgrade approach is implemented under COSR. The regulatory models provide insights into how both new and old alternatives to COSR might re-align customer and shareholder value.

Regulatory models are considered successful in this analysis when they both reduce overall costs to consumers and create a clear distinction in shareholder value creation between a conventional project and some alternative. This analysis presumes that the latter criteria are critical for the design of new regulatory models, since regulators face substantial information asymmetries vis-à-vis the firms they regulate. Furthermore, conventional solutions to grid problems have traditionally been capital-based, where optimal solutions to the same challenges in the future may increasingly rely on some combination of third-party resources and operational improvements. By highlighting impacts of different regulatory models on shareholder value and outcomes, regulators have a new toolbox to motivate utilities to identify innovative approaches beyond business as usual to achieve a reliable, affordable, clean electricity system.

RESULTS: LESSONS LEARNED FROM EXAMPLE UTILITY DECISIONS

The first example project in this paper considers an instance where a utility investment is needed to accommodate load growth in the distribution system. Three regulatory alternatives to COSR were considered:

1. A PIM that both rewards and penalizes utilities for performance against a peak demand target,
2. An allowed rate of return on procurement of third-party DERs, and
3. A revenue cap that includes a shared savings mechanism.

Among the alternatives considered, the rate of return on third-party resources appears to be worst-suited to align utility motivation with the preferred outcome. Even though shareholder value is increased substantially by granting a rate of return on the third-party DER expenditures, it is not enough to overcome the utility's capital bias under COSR. The fundamental tension this result reveals is that value creation under a rate of return on operational expenditures depends not only on the authorized rate, but also the size and length of the investment on which it is earned. Of course, the rate of return could be increased to account for this difference, but at a certain point this approach would unduly reward some technologies out of proportion with their value. Thus, this approach creates opportunities for better alignment between utility motivation and societal value, but may not create incentives for cost reduction at (r-k).

In contrast, a revenue cap and peak reduction PIM both create a stark distinction between shareholder value creation in the Conventional versus the DER Alternative strategies. In both cases, the alternative strategies become more attractive to utility shareholders than the conventional strategy while saving customers money. However, COSR makes the utility-owned DER option more attractive than a similar solution that could be obtained more cheaply from a third-party. Where operational savings that avoid capital costs exist, a revenue cap likely does a better job of aligning shareholder and societal value.

The second example follows a utility grid modernization investment where some (largely operational) aspects of the project can be provided at lower cost by third parties. Under COSR with frequent rate cases, these operational savings are treated as a pass-through and do not figure into utility decision-making. While jurisdictions have implemented PIMs to ensure customers realize the benefits of grid modernization (Munson, 2016), targeted incentives may be difficult to adapt to directly motivate large operational cost savings on their own. As a result, the regulatory alternatives in this example were limited to revenue caps, one set at cost of service and the other set at a lower level to reflect a “stretch factor” that reduces the attractiveness of the conventional approach. However, as shown in the third example, PIMs can be combined with a revenue cap to ensure utilities are properly motivated to balance affordability with other outcomes that society values.

The cost of service-based revenue cap rewards the utility for identifying cost savings in the grid modernization effort, generating earnings that greatly exceed those under COSR. The size of these earnings may be above levels regulators feel utilities should be rewarded for implementing a less costly strategy. In contrast, a revenue cap with a “stretch factor” provides an upside for the alternative that realizes operational savings and a substantial downside for the utility if it were to follow the conventional approach. Further, a revenue cap applied both capital and operational expenses holds the potential to motivate grid modernization investments that follow an efficient balance of capital and operational expenditures. Of course, these findings depend on assumptions about cost savings that will vary based on the project examined, or may not exist at all. Nevertheless, the relative effects of different models will hold true under a variety of real-life scenarios.

The final example considers a case where the utility is addressing a reliability need via a PPA with a natural gas power plant. Prudently-incurred costs under a PPA are typically passed through to ratepayers. In many jurisdictions, automatic adjustment clauses mean variations in fuel costs are considered outside of the utilities control, and so are always passed through. The same is typically the case for the pollution externalities in jurisdictions where emissions are priced. In both cases, utility shareholders benefit from passing the risk cost of variation in the price of fuel or emissions on to consumers.

Two symmetrical PIM-based mechanisms were considered for this example—one that focused on fuel costs and the other on CO_2 emissions. Each of these mechanisms successfully motivated the preferred outcome under the assumptions applied, despite the fact that the utility forewent $3 million in shareholder value by investing in DERs that avoid distribution upgrades. Each PIM tackled two sides of a common problem—the environmental externalities and price variability that results from dependence on fossil fuels, aligning shareholder value with two important and virtually universally preferred societal outcomes.

The revenue cap strategy also successfully motivated the preferred outcome on the presumption that it is less expensive than a conventional upgrade. One major risk of revenue caps is that they are set unrealistically high or low, resulting in arbitrary rewards or losses for the utility. In this case, the CO_2 PIM was added to the revenue cap to supplement this margin for error and ensure shareholder and societal values were aligned. This case was closest to the U.K.'s RIIO model, which is purported to have produced a high degree of alignment between shareholder and customer value (Fox-Penner et al., 2012).

ALIGNING SHAREHOLDER INCENTIVES WITH CUSTOMER VALUE AND DESIRED SOCIETAL OUTCOMES

This paper considered examples where clean energy alternatives to conventional grid upgrades are superior from both the perspective of cost and desired societal outcomes. In practice, there will be many, perhaps a majority of, instances where conventional grid upgrade strategies are preferable on both counts. Complicating matters more, there will be cases where a conventional strategy is preferable from a simple cost perspective, but society will still prefer alternative approaches given their ability to deliver desired outcomes against goals like environmental performance or resilience. At present, some tools used to drive preferred alternatives (e.g. net energy metering) destroy shareholder value, creating a tension between utilities' financial health and desired policy outcomes. A realigned utility revenue model holds the promise of rewarding, rather than harming, shareholder value when utilities are able to further policy and other societal goals.

The analysis in this paper indicates regulatory models combining a revenue cap and PIMs deserve greater consideration as jurisdictions determine how to align utility incentives with the outcomes society seeks. Under a revenue cap, a utility is rewarded when it is able to identify less costly approaches to meet grid needs. In past applications of revenue caps, cost savings took the form of more efficient implementation of conventional solutions. In contrast, a revenue cap model today would incentivize utilities to parse through the wide variety of new grid solutions that have been proposed, and implement those that benefit customers. For jurisdictions seeking to develop a more competitive market for energy services, a revenue cap also motivates utilities to procure third-party resources where they create more value under the cap. However, not all outcomes society seeks are likely to be priced using the cost comparisons a utility would undertake when faced with a revenue cap. For these outcomes, targeted PIMs can be a means to motivate performance where market-based value is absent.

Three Key Takeaways

1. *Cost of Service Regulation (COSR) creates utility incentives that are misaligned with societal value in circumstances where non-infrastructure or non-utility owned alternatives are superior from a societal perspective.*
2. *Performance Incentive Mechanisms (PIMs) hold the potential to monetize presently uncaptured benefits and costs in utility regulation, and to motivate utilities to perform against outcomes that society prioritizes*
3. *Revenue caps can be a powerful tool to align utility shareholder value creation with non-infrastructure-based strategies to meet grid needs. These tools deserve greater consideration, alongside and in combination with PIMs, in utility regulatory model discussions.*

RISK: MANAGING THE PACE OF TRANSITION

The implementation of a revenue cap plus PIMs model is not without significant challenges, and is likely to require substantial upfront regulatory effort. To start, a revenue cap creates the prospect of both windfall profits if set too high, or threats to utilities' financial viability if set too low. The challenges of setting a well-justified cap are exacerbated during a period of technological change and shifting policy priorities, where past performance of the firm or its peers will not offer a reliable prediction of future costs. These challenges suggest that forward-looking strategies to establish utility performance benchmarks may be required in order to determine an appropriate level of allowed revenues.

Given the scale of investments on the line, and the central role of power utilities in modern life, a gradual transition towards new regulatory models is likely warranted. In the (r - k) framework, gradual changes in the regulatory model could be important to managing investor perceptions of risk and avoiding increases in the cost of equity (k). Woolf and Lowry (2016) compare a variety of approaches and their alignment with jurisdictions' openness to regulatory change. Creating longer multi-year rate plans are of medium to high regulatory risk, targeted PIMs are low, and revenue reform is medium. All three together (e.g. imitating the RIIO transition) create the highest degree of change, and would require aggressive, risk-willing, well-resourced regulators (Woolf & Lowry, 2016).

Even within each regulatory model, gradual transition strategies can take different forms. Jurisdictions interested in using PIMs to modify traditional regulation could start with targets that are measurement-only or have low financial stakes. A revenue cap approach could begin with a narrow band of allowed returns, where deviations from this band trigger automatic adjustments to the cap. Alternatively, regulators could apply a revenue cap to a specific subset of expenditures, such as grid modernization, where non-conventional strategies are likely to exist.

The grid modernization example in this paper is an instance where a project-specific revenue cap could be beneficial. Applying a revenue cap to such a project would allow regulators and utilities to gain experience implementing, and performing against, a new regulatory model. Over time, the scale and scope of earnings at risk from new incentives mechanisms like PIMs or a cap can increase as PBR mechanisms are refined and regulators become more confident in the tools used to measure and value performance.

CONCLUSION

This paper examines the impact of new regulatory frameworks through the lens of the (r - k) "shareholder value engine." The (r - k) formulation of utility shareholder value creation is useful to understand how the returns allowed via different regulatory mechanisms affect utilities' motivation to achieve desired outcomes. The financial models in this paper assume that a societally-preferred alternative to conventional investments exists in some cases, and tests the ability of different regulatory models to motivate utility achievement of these outcomes. Among the options considered in this paper, a revenue cap most consistently and clearly aligns shareholder and customer value.

In practice, there will be investments where the societally-preferred outcome is more expensive. In these cases, the value these investments create cannot be unlocked via revenue caps alone. The implication is that, for jurisdictions targeting a broad set of outcomes for utilities, regulatory models that combine PIMs and revenue caps are worth examining. Though integrated approaches to PBR appear to be a substantial departure from regulatory practice today, jurisdictions can start slow when implementing new models.

However, the regulatory appetite for drastic reworking of the revenue model will vary from place to place. Gradual options such as measurement-only PIMs and revenue caps for subsets of utility investments can allow regulators to become more comfortable with large-scale change.

While a cautious approach is warranted, regulators should begin the process of evaluating which performance-based regulation tools are most appropriate for their jurisdiction. Doing so will enable regulators to avoid disruptive and sudden changes to their state's regulatory environment.

APPENDIX A: FINANCIAL DETAILS & REGULATORY ALTERNATIVES

In each example considered, the utility is assumed to have the financial characteristics set out in Table A-1.

	Table A-1: utility financial data		
Category	Figure	Explanation	Source
Cost of debt	6%	The interest rate on debt assuming a typical credit rating for a large investor-owned utility.	Based on various sources: ORA, 2015; EEI, 2012
Cost of equity	7.5%	The return equity investors require to invest in the utility stock. This can be thought of as the opportunity cost of investing; it is never fixed or exactly known.	Kihm et al., 2015
Proportion equity to debt	0.5	Utilities finance capital projects with a mix of debt (bonds) and equity (shareholders & stock). This mix is determined in the regulatory process.	PG&E, 2015
Tax rate	35%	This rate is applied to utility returns after debt-holders are repaid.	Federal corporate income tax rate
Tax gross-up	1.538	This multiplier is applied to the regulated rate of return on equity to account for taxes which are later taken out of utility returns. This effectively passes through the tax burden to customers.	Calculated: 1/(1 - tax rate)
Targeted return on equity	11%	Regulators set this rate based upon their assessment of a “fair” rate of return on equity investment. This can be different than the realized return on equity, which may vary from the targeted return based on a variety of regulatory and business risks.	High end of Kihm et al., 2015

Grossed-up targeted return on equity	16.92%	See Tax Gross-up above.	Calculated: Targeted ROE * tax gross-up
Allowed rate of return	11.46%	This is the rate against which capital investments in a utility's rate base are multiplied, resulting in a return on capital investments before debt and taxes are subtracted.	Calculated: Grossed-up ROE * proportion equity + cost of debt * proportion debt
Discount rate	7.5%	This reflects the decreasing value of money over time. It is used in the net present value calculations to quantify future shareholder value in present value terms.	Assumed to be equal to the cost of equity

Table A-1. Utility financial data

For the purposes of this analysis, these characteristics do not vary with the regulatory model under which the utility operates. This assumption is unlikely to hold in practice. For instance, the cost of equity reflects, in part, investors' perceptions of risk. If one regulatory model were perceived to be more or less risky than COSR, the cost of equity may rise or fall accordingly. These effects affect both the overall cost of providing service and utility motivation vis-à-vis the (r - k) shareholder value engine. However, the analytical task of identifying this sort of effect is beyond the scope of this analysis.

COST OF SERVICE REGULATION

Under the traditional COSR models, the utility's revenue requirement for each year is calculated using a simplified cost of service formula, where:

*Revenue requirement = (rate base * ROR) + annual depreciation + operating expenses + taxes*

Rate base is total capital infrastructure in service, less cumulative depreciation. The same rate of depreciation is assumed over the useful life of each project alternative; for example, the value of a project with a 20-year lifetime depreciates at five percent of its original value each year. Operating expenses are assumed to be constant year over year and are a pass-through. The utility's tax burden is calculated from its realized return, less debt service. In this formulation, shareholder value is defined as the earnings remaining after debt service, tax payments, and returns to existing shareholders at the cost of equity are accounted for. Therefore, for each year:

*ROR (rate of return) = (cost of debt * proportion debt) + (grossed up targeted return on equity * proportion equity)*

*Gross returns = rate base * ROR*

*Debt service = rate base * cost of debt * proportion debt*

*Tax payments = (gross returns - debt service) * tax rate*

*Required shareholder return = rate base * cost of equity * proportion equity*

Shareholder value = gross returns - debt service - tax payments - required shareholder return.

For each alternative, the total cost and total shareholder value for each year *i* are presented in terms of present value (PV), where:

$$\text{Total cost (PV)} = \sum \text{depreciation expense}_i + \sum \text{gross return}_i + \sum \text{operational expense}_i$$

or

$$\text{Total cost} = \sum \text{revenue requirement}_i / (1 + \text{discount rate})^{\text{useful lifetime}}$$

$$\text{Shareholder value (PV)} = \sum \text{shareholder value}_i$$

ROR ON THIRD-PARTY DER EXPENDITURES

In this case, the utility may earn either a COSR-based rate of return on a conventional investment or can procure third-party DERs to meet a grid need. All calculations for the conventional investment are the same as described above. However, if the utility elects to pursue the third-party DER option, then they are allowed a 3.5 percent return on their procurement costs, grossed up to 5.38 percent to account for taxes. This paper uses 3.5 percent a proxy for a typical difference between the allowed or targeted rate of return on equity (11 percent here) and the actual return on equity (7.5 percent here). It is assumed that the regulator allows this return for ten years, after which any remaining PPA costs are treated as a pass-through. Under the latter model, shareholder return is calculated as follows:

*Gross returns = annual procurement cost * grossed up ROR*

*Tax payments = returns * tax rate*

Shareholder value = returns - tax payments

The cumulative total cost figure for this example is calculated as:

$$\text{Total cost (PV)} = \sum \text{procurement cost}_i + \sum \text{return}_i + \sum \text{operational expense}_i$$

HIGH PERFORMANCE INCENTIVE MECHANISMS

This regulatory model is a modification of COSR, where the utility faces a Performance Incentive Mechanism (PIM) based on a peak demand target. If the demand exceeds the target, the utility is assessed a penalty. If the utility is able to reduce demand below the target, they may earn a bonus. The PIM is calculated based on any new MW savings or overruns net of the target. Penalties and payment are assessed at a rate of $200,000 per MW.

For example, if the target increases by 1MW year-to-year, but demand decreases by 1MW year-to-year, the PIM reward would be $400,000 in that year. This payment is manifested as a modification to the *gross-return* formula in the COSR regulatory model above, where:

*Gross returns = rate base * ROR +/- PIM*

REVENUE CAP

Revenue caps can be calculated through a variety of strategies apart from COSR accounting methods. For instance, econometric benchmarking against peer utilities or simulation of required revenues based on expected input costs are two approaches that have been used as alternatives to accounting methods. However, revenue caps in this example are calculated based on the annual revenue requirement under COSR regulation, making the models simpler and increasing the ease of comparison.

This is likely far from the ideal policy design, particularly because it is so susceptible to gaming, i.e., it gives the utility an incentive to produce inflated estimates of a conventional solution. Rather than make recommendations about the ideal design of a revenue cap, we stipulate the conventional solution as the basis for the cap to measure the incremental effects of implementing a revenue cap on shareholder value under the different solutions to meet the grid need:

*Revenue cap = ((rate base * ROR) + annual depreciation + operating expenses)*

The COSR revenue requirement is modified by "**stretch factors**" that simulate competitive pressure that is otherwise absent from a monopoly franchise, adding pressure to find cost savings where possible. A stretch factor reduces the revenue cap by a fixed percentage in each year:

*Revenue cap = ((rate base * ROR) + annual depreciation + operating expenses) * stretch factor)*

It is important to point out that, in practice, revenue cap regulation models allow some expenses to be passed through. However, in this paper it is assumed the revenue cap encompasses all expenditures. Under this model, utilities cover their financial obligations and create value for shareholders when they are able to reduce costs below the revenue cap. However, the utility does not retain all of these savings, since a proportion is shared with customers. As such, under this model:

*Gross return = (revenue cap - annual expenditures) * sharing proportion*

Similar to COSR, shareholder value is gross return less debt service, tax payments, and returns to existing shareholders. However, the utility only earns these returns over the course of its MYRP. This functions as a limit on how long utilities can either capture the benefits or suffer the penalties of their performance against the cap. In practice, it mitigates against the risks of a poorly set cap. After that period, the cap is adjusted to reflect the level of efficiency that utilities were able to achieve. Thus, after the MYRP, savings that would have been shared with the utility are entirely returned to customers. This is reflected in the "**true-up**" calculation:

True-up = gross returns$_{i > \text{length MYRP}}$ - debt service $_{i > \text{length MYRP}}$ - tax payments $_{i > \text{length MYRP}}$ - required shareholder return $_{i > \text{length MYRP}}$.

In the models used, total cost under a revenue cap is:

Total cost (PV) = ∑depreciation expense$_i$ + ∑gross return$_i$ + ∑operational expense$_i$ - ∑true-up

MODIFIED FUEL ADJUSTMENT CLAUSE (FAC)

Under the fuel-cost PIM regulatory model, a utility no longer automatically passes through all of its fuel procurement to consumers. Instead, the utility is required to develop a forecast of fuel prices. When fuel prices deviate from this figure, the utility either retains a proportion of the cost savings or overruns as determined by a "utility retention rate." Under the modified FAC:

*Base fuel cost = price-forecast * quantity of fuel used*

*Actual fuel cost = actual prices * quantity of fuel used*

Fuel deviation = base fuel cost - actual fuel cost

*Utility share = fuel deviation * (utility retention rate)*

*Customer share = fuel deviation * (1 - utility retention rate)*

In this paper, a utility retention rate of 50 percent is used to calculate both modifications to utility model revenues and the total cost of the procurement. So:

Shareholder value (PV) = ∑utility share / (1 + discount rate)^{years}

Total cost (PV) = (∑PPA costs + ∑customer share of fuel) / (1 + discount rate)^{years}

CO_2 PER MWH PIM

The CO_2 per MWh PIM applied in this regulatory model is based on the emissions of all power generated or procured by utilities. The emissions in Year 0 of this analysis are assumed to be 0.317 $MTCO_2$ per MWh, but by year 15 the utility must reduce this rate to 0.178 $MTCO_2$ per MWh. The intervening years are interpolated into a straight line emissions reduction path. These figures are based off Orvis et al. (2015). It is assumed the existing fleet generates 10,000 GWh of energy per year, and these units will exactly follow the emissions trajectory targeted by the PIM.

The financial value of the PIM is set to 25 percent of the median social cost of carbon (SCC) value of \$40 per $MTCO_2$ used by the United States government, for a total of \$10 per $MTCO_2$. This value is a proxy for an equitable split of the externality benefits between utility and customer, but would likely be calibrated differently in different states or jurisdictions.

The PIM is also awarded every eight years, giving the utility time to comply. But it also rewards the utility for performance in each year. In order to assess this PIM, emissions rates are converted to annual mass targets as follows:

*CO_2 emissions target (mass) = GWh fleet +/- GWh new * target MTCO2 / MWh*

*CO_2 emissions actual (mass) = GWh fleet * target MTCO2 / MWh + GWh new * $MTCO_2$ / MWh new*

*PIM payment/ penalty = $\sum_{\text{years1-8}}$ (CO_2 emissions target - CO_2 emissions actual) * SCC*

The present value of total PIM payments and penalties determines shareholder value. The total cost of each alternative is the conventional cost plus or minus the PIM.

APPENDIX B: PROJECT ALTERNATIVES

EXAMPLE 1: DISTRIBUTION CAPACITY UPGRADE

Setting

This example examines a case where load growth will lead to the capacity of a distribution system to be exceeded. The present peak demand is assumed to be 60MW, while the present infrastructure capacity is assumed to be 70 MW. Peak demand is forecast to grow to 76 MW in 10 years. The conventional solution would be to invest in infrastructure—like new substation transformers—to increase the capacity of the existing system. An alternative strategy is to invest in some combination of DERs (e.g. solar, storage, energy efficiency) that can provide sufficient performance to maintain a reliable system.

Assumptions

Conventional

The capital costs of a conventional strategy are based on Consolidated Edison's (ConEd) estimated cost of installing new transformers at the Glendale Substation, as reported in ConEd's Brooklyn-Queens Demand Management program (ConEd, 2014). There are limited data on the operational costs of a distribution upgrade project, so a figure of $250,000 per year was chosen, assuming maintenance and operation of the substation requires two full-time equivalent employees per year. The expenditures break out as follows.

Conventional: Capital Expenditures	
Year 1	$4,375,000
Year 2	$19,000,000
Year 3	$19,000,000
Year 4	$4,375,000
Operational Expenditures	
Annual	$250,000

Table B-1. Conventional: capital expenditures

For purposes of the revenue cap, however, capital expenditures are assumed to be upfront in Year 1, to facilitate a revenue cap design that rewards lower-cost options in any year.

Utility-Owned DER Alternative

This example is meant to illustrate an instance where a DER-based alternative is less capital-intensive than a conventional alternative. In order to achieve this result, it is assumed capital costs in each year are 80 percent that of the conventional alternative. Operational costs are assumed to be higher those in the Conventional approach. This incremental cost serves two purposes: The first is to account for potential increased costs of integrating new resources into the distribution system. The second is to demonstrate how variation in regulatory models leads to different outcomes on projects with higher ratios of operational to capital costs. Expenditures for this example break out as follows:

Utility-owned DERs: Capital Expenditures	
Year 1	$3,500,000
Year 2	$15,200,000
Year 3	$15,200,000
Year 4	$3,500,000
Operational Expenditures	
Annual	$500,000

Table B-2. Utility-owned DERs: capital expenditures

Third-Party DER example

This alternative assumes the utility procures a portfolio of DERs from third-party providers. This example stipulates that third-party DERs are the least costly approach. The utility procures these resources via a 10-year PPA, the payments of which are assessed by capacity. The length of the PPA is based on the regulatory model assessed in this example, where the utility is allowed to earn a return on a procurement for 10 years. In this example, the utility continues to incur operational expenditures, but at a lower level than utility-owned DER example because the third-party provider is assumed to provide some portion of O&M services. In order to compare this alternative to the previous projects, it is assumed the energy payments and operational costs are accrued for an additional 10 years. Expenditures for this example break out as follows:

Procurement Costs	
$ / W - annual for 10 years	$2.68 per W
Operational Expenditures	
Annual	$250,000

Table B-3: Third-party DERs: procurement costs and operational expenditures

The PPAs do not take place all at once, allowing a modular procurement approach. Instead, they are procured in tranches corresponding with the utility's peak reduction performance. This modular approach allows the utility to save even more money under the revenue cap, increasing shareholder value and saving customer money. The following procurement schedule was chosen:

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Capacity Additions MW	3	3	4	4	4	2									
yr1 10-yr PPA (3MW)	$802,500.00	$802,500.00	$802,500.00	$802,500.00	$802,500.00	$802,500.00	$802,500.00	$802,500.00	$802,500.00	$802,500.00					
yr2 10-yr PPA (3MW)		$802,500.00	$802,500.00	$802,500.00	$802,500.00	$802,500.00	$802,500.00	$802,500.00	$802,500.00	$802,500.00	$802,500.00				
yr3 10-yr PPA (4MW)			$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00			
yr4 10-yr PPA (4MW)				$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00		
yr5 10-yr PPA (4MW)					$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	$1,070,000.00	
yr6 10-yr PPA (2MW)						$535,000.00	$535,000.00	$535,000.00	$535,000.00	$535,000.00	$535,000.00	$535,000.00	$535,000.00	$535,000.00	$535,000.00
TOTAL	$802,500.00	$1,605,000.00	$2,675,000.00	$3,745,000.00	$4,815,000.00	$5,350,000.00	$5,350,000.00	$5,350,000.00	$5,350,000.00	$5,350,000.00	$4,547,500.00	$3,745,000.00	$2,675,000.00	$1,605,000.00	$535,000.00

Table B-4. 10-year PPA schedule

The PPA assumes flat yearly payments of $267,500/MW, or one-tenth of the total cost.

EXAMPLE 2: GRID MODERNIZATION

Setting

In this case, a utility is proposing an AMI roll-out including expenses for meters, communications upgrades, a new IT system, and project management. The Conventional approach would have the utility own all the infrastructure involved in this smart grid project, as well as have full operational control of the assets. An Alternative strategy would be to allow third parties to provide some smart grid infrastructure and services. This example considers an instance where a third party can provide communications infrastructure and services at a fraction of the cost of a utility option.

Assumptions

Conventional

The costs of a utility-owned and operated smart grid upgrade are based on ConEd's recent Smart Grid Business Plan filing to the NY PSC (ConEd, 2015). This example scales those costs down to a utility with 2.7 million customers, less than the number of customers served by ConEd. A wholly utility-owned and operated smart grid has the following costs:

Smart grid investment costs			
Category	Capital costs	Operational costs	Total Annual
AMI Meters	$593 million	$0	$593 million
Communications	$103 million	$264 million	$345 million
IT	$226 million	$491 million	$266 million
Project Management	$118 million	$143 million	$261 million
Totals	$1,020 million	$897 million	$1,917 million

Table B-5. Smart grid investment costs

In order to model these costs, equivalent upfront capital and annual operational costs were calculated. The capital costs are all assumed to be accrued in the first year of the financial model.

Alternative

The Alternative strategy assumes all the functions supported by the Communications line item could be provided by a third party. It is assumed the third-party can provide these services for an annual fee of $2 per customer. Over 2.7 million customers, that means the annual cost of Communications is $5.4 million per year. All other costs are assumed to be the same.

When third parties are allowed to participate, the total cost of the Communications line item becomes $55 million per year. The total cost of the smart grid deployment is therefore reduced to $1,626 million.

EXAMPLE 3: REGIONAL CAPACITY REQUIREMENT

Setting

This example examines an instance where there is insufficient generation capacity to maintain reliability within a region. The needed amount of capacity is assumed to be 700 MW. The conventional approach is to enter into a long-term contract with a natural gas power plant. An alternative strategy would be to contract with a smaller natural gas power plant in combination with procuring a portfolio of local DERs and bulk renewables.

Assumptions

Conventional approach

The costs of a Conventional strategy to address this grid need are calculated based on the following assumptions:

Conventional power plant physical characteristics		
Category	Figure	Source
Capacity	700 MW	Stipulated
Capacity Factor	0.55	Stipulated
Heat Rate	9,924 btu/kWh	EIA, 2016
CO_2 emissions rate	0.4 $MTCO_2$ / MWh	Stipulated

Table B-6. Conventional power plant physical characteristics

Based on these plant characteristics, the following inputs and outputs were calculated:

Conventional power plant energy and emissions		
Category	Figure	Source
Energy	3,103,000 MWh/ year	Calculated
Fuel	30,795,174 MMbtu / year	Calculated
CO_2 Emissions	1,241,240 $MTCO_2$ / year	Calculated

Table B-7. Conventional power plant energy and emissions

The financial details of the PPA are as follows:

Conventional power purchase agreement details		
Category	Figure	Source
Energy charge	$3.75 / MWh	Skinner, 2010
Capacity charge	$9.20 / kW-month	Skinner, 2010
Annual MWh Cost	$11,636,625	Calculated
Annual capacity charge	$77,280,000	Calculated

Table B-8. Conventional power purchase agreement details

Alternative details

The costs of a Conventional strategy to address this grid need are calculated based on the following assumptions:

Alternative power plant physical characteristics		
Category	**Figure**	**Source**
Capacity	300 MW	Stipulated
Capacity Factor	0.15	Stipulated
Heat Rate	11,347 btu/kWh	EIA, 2016
CO_2 emissions rate	0.45 $MTCO_2$ / MWh	Stipulated

Table B-9. Alternative power plant physical characteristics

Based on these plant characteristics, the following inputs and outputs were calculated:

Alternative power plant energy and emissions		
Category	**Figure**	**Source**
Energy	362,700 MWh/ year	Calculated
Fuel	4,115,555 MMbtu / year	Calculated
CO_2 Emissions	163,215 $MTCO_2$ / year	Calculated

Table B-10. Alternative power plant energy and emissions

The financial details of the PPA are as follows:

Alternative power purchase agreement details		
Category	**Figure**	**Source**
Energy charge	$3.75 / MWh	Skinner, 2010
Capacity charge	$9.20 / kW-month	Skinner, 2010
Annual energy cost	$1,360,125	Calculated

Annual capacity cost	$33,120,000	Calculated

Table B-11. Alternative power purchase agreement details

The Clean Alternative is designed to bridge the gap between both the amount of capacity and energy produced under the Conventional approach. The cost of clean energy is assumed to be $48 per MWh, reflecting a combination of DERs and grid-scale renewables. The details of the Clean Alternative are as follows:

Clean Energy details		
Category	**Figure**	**Source**
Capacity	817 MW	Stipulated & Calculated
Energy	2,949,930 MWh	Calculated
Annual energy cost	$143,488,000	Calculated

Table B-12. Clean energy details

The utility procured the following mix of DERs and utility-scale wind and solar:

Energy Efficiency	150 MW
Distributed solar PV	50 MW
Utility-scale solar PV	300 MW
Utility-scale wind	300 MW

Natural gas price forecast

In this example, the utility must create a natural gas price forecast in order to estimate the total cost of each alternative. The forecast starts from Henry Hub natural gas prices as of March 2016 (EIA, 2016). Each following year is calculated by using levels of annual price increases found in the Energy Information Administration's 2015 Annual Energy Outlook (EIA, 2015).

The actual cost of the project, and assessment of the natural gas PIM, depends on the actual cost of natural gas in each year. To calculate "actual" prices, a price was randomly drawn for each year from uniform distributions whose means were higher than the forecast price. Simulated prices are therefore systematically higher than the price forecast, as shown in *Figure B-*.

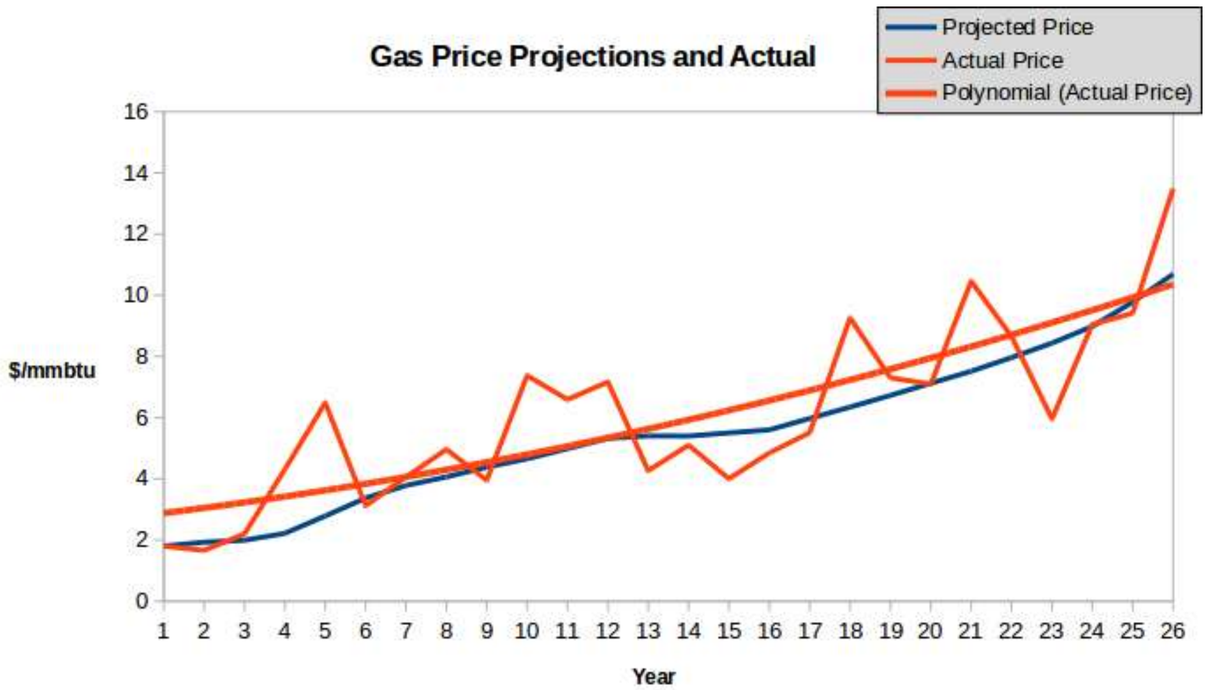

Figure B-1. Natural gas price forecasts and actual

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