OPTIMIZING CAPITAL AND SERVICE EXPENDITURES

Providing utilities with financial incentives for a changing grid

A 21st Century Electricity System Issue Brief

By Advanced Energy Economy

September 2017

ADVANCED ENERGY ECONOMY

San Francisco | Washington D.C. | Boston
aee.net | powersuite.aee.net | @aeenet

ABOUT ADVANCED ENERGY ECONOMY

Advanced Energy Economy (AEE) is a national association of businesses and business leaders who are making the global energy system more secure, clean and affordable. Advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting energy needs today and tomorrow. AEE's mission is to transform public policy to enable rapid growth of advanced energy businesses. AEE and its State Partner organizations are active in 26 states across the country, representing roughly 1,000 companies and organizations in the advanced energy industry. Visit www.aee.net for more information.

ABOUT THIS ISSUE BRIEF

The U.S. utility sector has entered a period of foundational change not seen since the restructuring of the late 1990s. Change is being driven by new technologies, evolving customer needs and desires, environmental imperatives, and an increased focus on grid resiliency. With these developments come challenges, but also new opportunities to create an energy system that meets the changing expectations of consumers and society for the coming decades. We call this the *21st Century Electricity System:* a high-performing, customer-focused electricity system that is efficient, flexible, resilient, reliable, affordable, safe, secure, and clean. A successful transition to a 21st Century Electricity System requires careful consideration of a range of interrelated issues that will ultimately redefine the regulatory framework and utility business model while creating new opportunities for third-party providers and customers to contribute to the operation of the electricity system.

To support this transition, Advanced Energy Economy (AEE) has prepared several issue briefs that are intended to be a resource for regulators, policymakers, and other interested parties as they tackle issues arising in the rapidly evolving electric power regulatory and business landscape.[1] This issue brief on **Optimizing Capital and Service Expenditures** describes this emerging issue, reviews regulatory approaches for putting capital and service spending on an even playing field, and makes general recommendations on a path forward.[2]

SUMMARY

Throughout the economy, companies are finding new efficiencies and operational benefits by meeting technology needs through services provided by third parties rather than investing in physical assets that they own and manage.[3] However, this trend toward services has been slow to take hold in the utility industry because it conflicts with the prevailing utility business model. Since capital investments are the main driver of utility profits in this model, services that can improve the utilization of, defer, or replace capital investments have the effect of reducing utility opportunities for profit. This can bias utilities away from service-based alternatives that may be more cost effective for their customers. Since many state-of-the-art technologies are offered only as a service, utilities face an artificial barrier to improving the quality and cost-effectiveness of the electric power service delivered to their customers.

As more technologies shift to services, this not only presents a barrier to optimizing investments but also a threat to the stability of utility earnings. While utilities may not have a financial motivation to look for greater efficiencies through technology-based services, the cost-effectiveness of these services may push utilities in this direction anyway. Realizing that both customers and utilities stand to benefit through equalizing the earnings opportunities between traditional capital solutions and service solutions that can replace them at lower cost, several state utility commissions have explored mechanisms to correct the bias toward capital investments that is inherent in cost-of-service regulation.

Some of these mechanisms, such as capitalization of a service contract or the use of regulatory assets,[4] are often used today without any changes in regulation. These mechanisms allow utilities to place "service assets" in the rate base and depreciate them like capital investments. Other possible regulatory mechanisms could provide additional motivation, such as allowing the utility to retain a share of the cost savings from service-based solutions. This issue brief will explore the impacts of different regulatory mechanisms and make some general recommendations for implementation.

NEW SERVICES FOR UTILITIES

As new technologies develop today, they are frequently offered as a service, where the provider owns the technology, operates, and maintains the technology and guarantees an outcome or an output in the contract. This is in contrast to the sale of a technology as a physical asset, where the maintenance, operation, and final outputs are the responsibility of the purchaser. Services take advantage of the experience of specialized companies in operating specific types of assets, and can provide significant value compared to an ownership-based model. Often these services can be delivered more effectively because the service provider pools assets and more efficiently utilizes capacity, compared with each utility acquiring enough capacity to serve its own needs.

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

These principles that apply to cloud computing – scalability, flexibility, security, resource efficiency – often apply to other parts of the utility business. Various forms of non-wires alternatives (NWAs) rely on services that, in many cases, can effectively replace utility capital expenditures. Take, for instance, a distribution transformer that is reaching its capacity limit due to growing peak demand in the summer. On one of the feeders served by the transformer, a large customer is considering purchasing a battery for reliability and to reduce their demand charges. The utility could contract for dispatch rights on the battery during the top summer demand hours, alleviating the need to invest in an expensive new transformer. The customer can make use of the battery during the other hours for energy arbitrage, backup power, and demand charge savings. While the utility saves by not purchasing an expensive transformer, it is in essence replacing that equipment and capital investment with a service contract for dispatch rights. The same scenario is applicable to a contract with a demand response provider, which pays its customers to reduce peak demand, aggregates that peak demand reduction, and sells it to the utility to offset the need for the new transformer investment.

As described in depth later, the loss of earnings that a utility incurs by choosing more cost-effective, service-based options can be offset through a number of methods that aim to provide utilities with equivalent earnings.

THE REGULATORY MODEL AND UTILITY PROFIT DRIVERS

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

The way that utility shareholders profit is that regulators usually afford investors an opportunity to earn a higher rate of return on their equity than the cost of equity[5] – the return provided by other companies in the economy with a similar risk profile. This is part of what makes utilities an attractive investment. Currently, utilities around the country are allowed to earn an average of 10%[6] return on equity while companies with a similar risk rating on average yield about 7.5%.[7] The 2.5% difference is *economic* profit. This spread between the cost of equity and the return on equity (often referred to as *r-k*) is the driver of investment for a utility. If regulators provide a return that is lower than what other companies provide, investors incur opportunity costs. Capital would likely leave utilities for higher returns at other companies with a similar risk profile, harming the ability of utilities to make necessary investments. However, allowing investors to earn an above-market rate of return has the opposite effect and drives utilities to increase their capital investments. As utilities invest more in transformers, wires, and other plant, profits increase.

In addition to capital expenditures, utilities can also increase earnings through closely managing their operating expenditures, such as maintenance, salaries, and fuel. These operating expenditures are recovered in rates, but unlike capital expenditures, utilities do not earn a rate of return on them. Instead, as an incentive to keep costs down, operating expenditures that exceed the level provided in a utility's current rate plan are, up to a set threshold, paid out of the utility's earnings and are not passed on to customers. Additionally, many states have an Earnings Sharing Mechanism (ESM), which allows a utility to retain a share of unspent operating funds as profit to incentivize efficient use of operating funds. In some cases, these unspent funds can be invested in capital and earn a return, thus expanding the rate base without special regulatory approval. As a result, utilities work to minimize their operating expenditures, both to avoid the risk of expenditure overruns eating into their profits and to potentially retain some of the unspent operating funds as profit.

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

Today, due to innovations in technology and business models, utilities have far more options for meeting their operating goals of reliability, safety, cost-effectiveness, and quality of service. In some cases, operating expenditures (such as services from SaaS and distributed energy resources[8]) can more cost-effectively fulfill system needs than the traditional capital investments. But shifting spending from capital investment to operating expenses runs counter to the incentive structure favoring fixed, long-lived capital assets that still predominates in the utility sector.

This presents a dilemma. Utilities take very seriously their responsibility to serve customers with safe and reliable power, but they also take seriously their duty to deliver earnings to their shareholders. Thus, the regulatory framework at times makes utilities choose between serving the best interests of their customers and serving the best interests of their shareholders. For the reasons described above, utilities lack the right incentives to minimize their capital costs, especially if the reduced capital costs are accomplished through an increase in operating expenses.

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

UTILITY ACCOUNTING

In discussing the utility business model, it is necessary to briefly touch on accounting rules. Utilities need to comply with two different accounting standards, the Uniform System of Accounts (USofA) established by Federal Energy Regulatory Commission (FERC) and the U.S. Generally Accepted Accounting Principles (GAAP) adopted by the Securities and Exchange Commission. Each serves a different purpose.

FERC established USofA to create uniformity in reporting and to provide the Commission with the information it needs to carry out its duty of ensuring that the rates of jurisdictional utilities are just and reasonable. GAAP was created to provide standards for the financial statements of public companies. GAAP is meant to increase transparency and uniformity in public financial statements for the benefit of investors, while USofA is meant to provide energy regulators with sufficient and accurate information to perform their oversight duties. FERC has been clear that USofA, not GAAP, is the key accounting system for regulatory purposes, noting that if GAAP conflicts with the accounting and financial reporting needed by regulators to fulfill their statutory responsibilities, then USofA supersedes GAAP.[9]

Most states voluntarily adopt USofA as published by FERC,[10] but state utility commissions have the ability to adapt them. While implementation will require less change if new regulatory mechanisms are compatible with existing accounting standards, these standards are not limitations on state authority. If a commission believes that it can better protect customers and improve the way utilities earn a fair return through regulatory changes that are incompatible with USofA and GAAP, it has the authority to do so. Some specific examples are given below.

REGULATORY SOLUTIONS

A number of states have explored or enacted solutions that attempt to address the loss of earnings to utilities when services replace capital expenditures. Below are some general observations about the potential strengths and weaknesses of each regulatory solution.

CAPITALIZATION OF A PRE-PAID SERVICE CONTRACT

The first solution is to pre-pay the total cost of a service contract for a specified term and place the amount of pre-payment in the rate base. This would allow the utility to depreciate the contract over a number of years and collect carrying costs (which include the shareholders' return on equity) on the undepreciated amount until the contract is fully depreciated. In this case, the pre-paid contract functions as any physical asset would in the utility's rate base.

Arguably, this is only a minor departure from the current regulatory framework, and for some types of services, would not require adjustments to regulation and accounting practices at all. For instance, regulatory assets are commonly used in many states where large expenses are paid but then carried by the utility (with carrying costs) in order to avoid immediate impact on rates. An example of this is plant decommissioning. Under USofA, utilities may place services into one of several different accounts. For instance, Software-as-a-Service can be placed in USofA Account 303, which is reserved for Miscellaneous Intangible Plant.[11] Another option is USofA Account 165, which is reserved for pre-paid contracts.[12]

For state regulators looking for a first step to resolve the impact of lost earnings by utilities choosing a service solution rather than a capital investment, this capitalization approach is a good option, but it does have several limitations.

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

Second, the lifespan of the asset also matters in determining total utility returns, as depreciation is tied to the useful life of the asset. If the contract is only for three years, the value will depreciate at 1/3 of total value per year. Compare this to a 30-year asset, which depreciates at 1/30th per year. As utilities earn carrying costs (which includes investor return) yearly on the undepreciated value, a shorter lifespan is less attractive than a long one. The same amount of initial investment can provide a larger amount of return over time if it has a longer useful life.

Third, as capitalization requires a service contract to be paid up-front so that the costs can be depreciated over time, services that are available only short term or only through yearly service contracts are not compatible with this approach. As an alternative, some approaches below allow for services to be treated as short-term expenses.

NEW YORK: NON-WIRES ALTERNATIVE SHAREHOLDER INCENTIVES

The New York Public Service Commission has implemented a NWA shareholder incentive,[13] which combines the capitalization of service costs, as described in the first solution of this section, with a shareholder incentive consisting of a share of the benefits produced by the NWA relative to a traditional solution. If a utility chooses to defer or avoid a distribution upgrade through NWAs, the utility can recover the costs of the NWA, including the cost of incentive payments paid by the utility to customer and third-party owned resources, over 10 years and collect its carrying costs over that time.

This functions as a regulatory asset, as previously described. However, in order to encourage the utility to pursue more cost-effective solutions, the utility can also receive a 30% share of the difference between the net present benefits of the NWA and the traditional solution that it replaces. The net benefits of each project are determined by New York's Benefit Cost Analysis (BCA) framework, which includes societal benefits such as emissions and carbon reduction in addition to energy and capacity benefits. For other states that want a simpler process or narrower range of benefits considered, the total cost of the NWA and projected cost of the avoided capital expenditures (including carrying costs) could be compared, and the incentive could be set as a share of the difference.

As the utility's incentive is based on a share of the net benefits, which are the remaining benefits after costs are subtracted, the utility should be motivated to keep down the cost of implementing the NWA. In addition, Con Edison requested and received regulatory approval for an additional cost-efficiency incentive. Cost overruns and underruns are shared 50/50 between Con Edison and its customers. If the utility reduces costs, it can share in the savings up to 50% of the net present benefits of an NWA. On the flip side, if there are cost overruns in implementing the NWA, the incentive can shrink all the way to zero.

The benefit of the NWA shareholder incentive is that it initially provides the same earnings opportunity for NWA solutions and the avoided capital expenditures. They would both receive upfront investment that would be depreciated over time with the utility return applied to the yearly undepreciated amount. But it goes further and looks at the total lifetime costs and benefits of each solution and provides the utility with an incentive set as a share of the net benefit.

While this mechanism provides a number of good efficiency signals to utilities, it is more complex to implement. The NWA and avoided investment must both undergo a BCA. As discussed above, this could by simplified by merely comparing total costs of the NWA solution vs. the traditional solution. This mechanism also presents the potential for gaming if the utility attempts to inflate the costs of a traditional investment in order to increase the savings and net benefits of the NWA solution. While this type of problem is not new for commission staff, who regularly scrutinize utility capital plans, this mechanism may strengthen the incentive for utilities to inflate them. Additionally, as this solution relies on the capitalization of an expense, it must also be prepaid rather than paid out over time like most payments for services.

NEW YORK: "MODIFIED CLAWBACK MECHANISM"

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

During the course of the Reforming the Energy Vision Proceeding, the NY PSC ordered[14] changes to address the potential for the clawback mechanism to interfere with the goal of encouraging utilities to rely on DERs for NWA projects. If the utility were to avoid a capital expense with a DER contract, the clawback mechanism would reduce the capital budget and earnings by the amount associated with the avoided capital investment, while the DER would be procured with a service expense for which the utility would get no additional rate recovery (and therefore risk eating into utility profits through operating expense overruns).

The modification the PSC ordered is relatively simple. If the utility shows that a portion of its capital budget was avoided by a service expense for DER, the clawback mechanism will not be implemented on that portion of the budget. The utility will retain the avoided portion of the capital budget and associated earnings and pay out the service expense without additional rate recovery. As long as the yearly service expense is less than the yearly amount of depreciation and carrying costs in the capital budget, the utility will profit by retaining the savings.

This mechanism has a number of positive traits. First, it allows the utility to share in the savings from making a less expensive service expenditure. Until its next rate case, the utility captures all of the savings, and in following years, the customers receive all of the savings. Also, as the savings are generated through a comparison of yearly costs, the service expenditure can be paid out on a yearly basis and does not need to be prepaid. As long as the yearly expense payments are lower than the cost of the capital investment, customers benefit.

The primary disadvantage of the modified clawback mechanism is that it is only effective for a short time, i.e., for the period of the rate plan. In New York, utilities must file a rate case every three years. After the next rate case, the utility's operating expense budget will increase to include the cost of the DER expense, but the utility will no longer retain the savings from the avoided capital investment. While this covers the ongoing cost of the DER expense, so the utility does not have to absorb it, only during the rate plan in which the initial capital investment was avoided does the utility effectively earn on the DER expense.

If the utility retains the savings only until the next rate case, then the maximum amount of time a utility can earn on the savings is for three years (in the case of New York). This may be sufficient for an asset that lasts five to 10 years, but it is likely to fall well short of providing the earnings expected from a 30-year investment. The timing of the investment can also be a constraint. If the investment happens early in the rate plan period, then the utility can earn for three years, but if the utility makes the investment shortly before the rate plan ends, it may not be able to retain any savings as earnings. Nevertheless, as one of several modifications to earnings that regulators can implements, the modified clawback mechanism can help to incentivize utilities to pursue cost-effective service options.

CALIFORNIA: DER INCENTIVE PILOT

The California Public Utility Commission is piloting[15] a different method for compensating utilities for avoided earnings on NWA expenses. Instead of capitalizing the expense as a regulatory asset, California provides an incentive to the utilities that amounts to 4% of the value of the service expense. This is meant to represent the value of the foregone earnings to shareholders. In the proceeding, there were differing justifications cited for the 4% level. Some argued it would represent the forgone economic earnings relating to the difference between the shareholder's cost of equity and return on equity, as was described earlier as "r-k."[16]

The incentive is a simple solution that aims to provide earnings on a service expense as an offset to the earnings forgone in a capital expenditure. However, as the incentive is based on the cost of the service expense rather than the avoided asset, the utility may still have to forgo greater earnings when it chooses a more cost-effective solution. Even if the incentive is applied to a service expense of equivalent value to the yearly depreciation cost of a capital investment, it will not provide earnings that approach those of a capital investment. The carrying costs on a capital investment are applied to the undepreciated amount, which is many multiples larger than the size of the yearly depreciation until the last year of the asset's useful life. The incentive also provides no means of sharing the savings of an avoided expenditure. On the plus side, the incentive is flexible. As the incentive is based on yearly service costs, it is potentially more suitable for short-term investments of one or two years.

CONCLUSION

States are exploring a number of methods to help utilities efficiently optimize their operating and capital expenditures and deliver better value to customers. Some states are going further by counterbalancing the predominant utility incentive to deploy capital to increase earnings with mechanisms that share the savings when they spend less. One approach, capitalizing service expenditures, is consistent with how states treat regulatory assets today and state commissions could easily adjust their practice to include expenses that cost-effectively offset capital investments. Regulators and utilities can move forward incrementally as they gain more experience in capitalizing these service expenses. As a second approach, commissions could introduce shared-savings mechanisms to provide the utility an incentive to deploy capital more efficiently.

If these regulatory reforms function act as designed, the net effect will be a reorientation of incentives in the regulatory model toward motivating utilities to explore new technologies and seek out efficiencies within their own systems as a means for both increasing profits for their shareholders and delivering better and more cost-effective service to their customers. Utilities should also become more neutral as to who owns an asset if the utility can profit from the asset whether it is owned by itself, a customer, or a third-party. Providing an opportunity for utilities to earn by optimizing their investments and driving down costs should also make the regulatory process easier and potentially less contentious.

END NOTES

[1] http://info.aee.net/21ces-issue-briefs
[2] Advanced Energy Economy (AEE) is comprised of a diverse membership. As such, the information contained herein may not represent the position of all AEE members.
[3] The simplest example is a company that decides to lease, rather than own, a fleet of vehicles. Examples within utility procurement are numerous, as explained later, but they include a utility contracting for Software-as-a-Service rather setting up a data center, or a utility contracting for targeted demand response rather than upgrading a transformer.
[4] Regulatory assets are costs or revenues that a regulatory agency permits a utility to place in its balance sheet, effectively treating it like a capital investment.
[5] This concept is explained in much greater detail in a paper published by America's Power Plan. It is recommended reading for anyone interested in greater detail on the subject. See: *You Get What You Pay For: Moving Toward Value in Utility Compensation.* By Steve Kihm, Ron Lehr, Sonia Aggarwal, and Edward Burgess. Available at: http://americaspowerplan.com/wp-content/uploads/2016/07/CostValue-Part1-Revenue.pdf
[6] Average of current allowed returns on equity for major IOUs as listed in PowerPortal, part of Advanced Energy Economy's PowerSuite tools. https://powersuite.aee.net/portal/states
[7] See *You Get What You Pay For: Moving Toward Value in Utility Compensation.*
[8] Distributed energy resources (DER) is defined broadly to include distributed generation of all types, demand response, energy efficiency, energy storage, electric vehicles and the associated electric vehicle supply equipment, and microgrids.
[9] FERC Order No. 552, Issued March 31, 1993.
[10] USofA is mandatory for only those units of utilities that are under FERC's jurisdiction, such as transmission operators. Code of Federal Regulations, Title 18, Part 101.
[11] USofA account 303: "This account shall include the cost of patent rights, licenses, privileges, and other intangible property necessary or valuable in the conduct of utility operations and not specifically chargeable to any other account."
[12] USofA account 165: "This account shall include amounts representing prepayments of insurance, rents, taxes, interest and miscellaneous items, and shall be kept or supported in such manner as to disclose the amount of each class of prepayment."
[13] Order Approving Shareholder Incentives, New York Public Service Commission, January 25, 2017, in proceeding 15-E-0229.
[14] Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. New York Public Service Commission. May 19, 2016. Proceeding 14-M-0101.
[15] Rulemaking 14-10-003.
[16] It is interesting to note that the CPUC applied the 4% incentive to the total value of the service expense rather than 50% of the total value, which would more closely resemble how a company's return on equity is applied to the value of a capital asset. Utilities fund their capital investments with both debt and equity at a ratio regulated by state commissions. In most cases, equity only funds around 50%, so the return on equity is applied to only this share.