

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

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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 efficiencies and operational benefits by meeting their needs through services provided by third parties rather than investing in physical assets that they own and manage.³ Utilities are no different. However, the trend toward services has faced some unique barriers in the investor-owned utility industry, as utilities have an issue in their underlying business model, imposed by regulation, that most other businesses do not.

In the current cost-of-service regulatory model, which has served the sector and customers well for many years, capital investments are a large driver of returns to utility shareholders. Utility investors are allowed to earn a rate of return on net invested capital (gross capital minus accumulated depreciation). In contrast, operating costs (such as fuel, labor, maintenance, and service expenses)⁴ are generally passed through to customers in electric rates without the utility making any direct profits on them, although utilities remain incented to manage operating costs to reduce overall cost to customers, and also to manage profits between regulatory rate reviews.

Over the long term, however, services that can improve the utilization of, defer, or replace capital investments may have the effect of

reducing opportunities for utilities to generate earnings. Because many new technologies are offered only as a service, utilities may be discouraged from using them. Realizing that both customers and utilities stand to benefit from equalizing the earnings opportunities between traditional capital solutions and service solutions that reduce capital investment needs, several state commissions have explored or implemented mechanisms to compensate for the bias toward capital investments that is inherent in cost-of-service regulation.⁵

Some of these mechanisms, such as capitalization of a service contract or the use of regulatory assets,⁶ are often used today without any changes in regulation. These mechanisms allow utilities to place “service assets” in the rate base and amortize 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 provides an overview of these mechanisms. AEE Institute published a [more in-depth paper](#) on these mechanisms that models their impact on customers and utilities. That paper can be found [at: https://info.aee.net/aee_institute_utility_report](https://info.aee.net/aee_institute_utility_report)



NEW SERVICES FOR UTILITIES

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

Cloud computing is a 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 in onsite computing capacity and internal staff development to make all of the resources function properly. If the utility were to purchase cloud computing services, with all of the security and IT infrastructure supplied by the service provider

and its own network of partners and vendors, the utility could leverage the specialization and expertise of the provider and benefit from cost efficiencies through use of shared infrastructure (the provider's data center). Cloud computing also allows utilities to scale capacity up or down on demand, providing much greater flexibility than a system that is owned and operated by the utility. Making use of cloud computing also ensures that the systems are always up to date, will not become obsolete, and are easier to keep secure. However, for regulated utilities, if cloud computing is treated as a service expense, it replaces an earnings opportunity – the capital expenses related to IT infrastructure and software upon which a utility can earn its regulated rate of return – with a service expense that earns the utility no return.

These principles that apply to cloud computing – scalability, flexibility, security, resource efficiency – often apply to other parts of the utility business. Various forms of non-wires alternatives (NWA) 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 can pay its customers to reduce peak

demand and offset the need for a capital investment in a new transformer.

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 amortization or depreciation) plus the cost of debt and return on equity (the cost of capital or carrying costs) on the unamortized balance. 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. This provides a real benefit to customers in the form of lower bills.

The primary way that utility shareholders benefit is that regulators usually afford investors an opportunity to earn a competitive rate of return on their equity that is marginally higher than the shareholder's expected return, which is based on the return provided by other companies with a similar risk profile in the economy.⁷ This is part of what makes utilities an attractive investment. If regulators provide a return that is lower than what comparable companies provide, investors incur opportunity costs. Raising new capital would become expensive for the company and would decrease the value of equity for existing shareholders, harming the ability of utilities to make necessary investments in the long run. However, allowing investors to earn a rate of return on equity above shareholders' expected return motivates utilities to increase their capital investments as it increases shareholder value. As utilities invest more in transformers,



wires, and other assets, shareholder value increases (and customers also benefit from investments in the grid). While setting the allowed return on equity to the exact amount investors require for a utility's level of risk would theoretically leave a utility indifferent toward capital investments, it would also provide no real value to shareholders for investing in a utility relative to their other options. In order to attract new capital on favorable terms, utilities need to provide shareholders with value, and therefore a reasonable premium on the allowed return on equity over the return on similarly risk-rated equity in the market is necessary.

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

short-term basis, until the utility's next rate plan is implemented.

Additionally, many states have an Earnings Sharing Mechanism (ESM) that allows a utility to retain all or a portion 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 for services procured from third-party providers (such as cloud computing and distributed energy resources [DER]⁸) may 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 that still predominates in the utility sector and favors fixed, long-lived capital assets.

This presents a dilemma as utilities can take a financial hit in two ways when they replace capital with a service. Utilities take very seriously their responsibility to serve customers with safe and reliable power, but they also appropriately take seriously their duty to deliver earnings to their shareholders. Thus, the regulatory framework at times may make utilities choose between serving the best interests of their customers and serving the best interests of their shareholders. We say this though, recognizing that each utility's capital investment plans are reviewed, and in many states approved, by regulators. 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 (which do not earn a return); and especially when those expenses are not built into rate forecasts.

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

UTILITY ACCOUNTING

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 may, and often do, adapt them. While implementation new regulatory mechanisms will require less change if they 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; however, such departures should be avoided. As explained in detail in AEE Institute's paper, the regulatory mechanisms discussed below are all consistent with applicable GAAP and USofA standards.

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 amortize the contract over a number of years and collect carrying costs (which include the shareholders' return on equity) on the unamortized balance until the contract is fully amortized. 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, cloud computing 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 amortize at 1/3 of total value per year. Compare this to a 30-year asset, which amortizes at 1/30 per year. As utilities earn carrying costs (which includes investor return) yearly on the unamortized balance, 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 amortized 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

On January 25, 2017, the New York Public Service Commission (NY PSC) issued an *Order Approving Shareholder Incentives*¹³ concerning a proposed NWA shareholder

incentive for Consolidated Edison (Con Edison), the utility serving New York City. The Order provides for a shareholder incentive that is based on a 30% share of the difference between the net present benefits of the NWA and the traditional solution that it replaces, in order to encourage the utility to pursue more cost-effective solutions. The net benefits of each project are determined by New York's Benefit Cost Analysis (BCA) framework that includes societal benefits, such as carbon reductions, in addition to energy and capacity benefits. If a utility chooses to defer or avoid a distribution upgrade through NWAs, the utility can recover the costs of the NWA, including the cost of service payments from the utility to customer and third-party owned resources, over 10 years and collect its carrying costs over that time. The utility would record the NWA costs as a regulatory asset as previously described. The shareholder earnings incentive is added on top of the capitalized regulatory asset. And as an added incentive, cost overruns and underruns are shared 50/50 between Con Edison and its customers, which effectively decrease or increase the company's incentive. If the utility reduces costs significantly, it can share in the savings up until the total incentive reaches 50% of the net present benefits of an NWA. On the flip side, if there are cost overruns in implementing the NWA, the incentive can shrink all the way to \$0.

The major benefit of the NWA option is that it provides for the deferral of a larger capital project, which can save the utility and its customers money, while providing the utility an earnings opportunity for NWA solutions. Like the capitalization of a prepaid contract,



the NWA option relies on a prepaid multi-year service expense that would be amortized over time as a regulatory asset with the utility return applied to the yearly unamortized balance. But it goes further and provides an incentive based on net benefits.

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. This could be 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 commissions who regularly scrutinize utility capital plans, it may argue for additional care in the review of an investment that is used as a benchmark for a shared savings mechanism. Additionally, as this solution relies on the capitalization and amortization of an expense, 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 through a different way. If a utility is looking to boost short-term earnings, a utility can underspend relative to its planned capital budget upon which rates are based. When it does so, the utility is able to retain the

savings as earnings until its next rate plan period. (A utility that chooses this would sacrifice the greater long-term earnings on capital investments that were never made.) To compensate for this short-term incentive to underspend, the traditional 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 ordered¹⁴ changes to address the potential for the clawback mechanism to interfere with the goal of encouraging utilities to rely on DER for NWA projects that replace utility capital expenditures. If the utility were to replace a capital expense with a DER contract, the clawback mechanism, as currently structured, would reduce the utility revenue and earnings by returning the unspent capital and earnings associated with the avoided capital investment to ratepayers. Simultaneously, the cost of the service payments would increase the utility’s operating expenses beyond what was included in rates (and therefore risk eating into utility profits through operating expense overruns).

The modification the NY 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 for the service expense without additional rate recovery. Thus, as long as the yearly service expense is less than the yearly amount of amortization and carrying costs in the capital budget, the



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

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 annual costs, the service expenditure can be paid out on an annual basis and does not need to be prepaid. As long as the annual expenses are lower than the annual 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 generally 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, it may not leave the utility neutral during the years following the initial rate case as the capital investment may still be deferred over the life of the DER expense. Only during the rate plan in which the initial capital investment was avoided does the utility effectively earn on the DER expense.

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 fairly short (no more than 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 up to 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 implement, the modified clawback mechanism can help to incentivize utilities to pursue cost-effective service options.

California: DER Incentive Pilot

The California Public Utilities Commission is piloting¹⁵ a different method for compensating utilities for avoided earnings on NWA expenses. Instead of capitalizing the expense as a regulatory asset, California provides an incentive to the utilities that amounts to 4% of the value of the service expense, which is passed on to customers via an automatic adjustment mechanism. The 4% is meant to represent the value of the foregone earnings to shareholders. There were differing justifications cited in the proceeding that established the pilot for the 4% level. Some argued it would represent the forgone economic earnings relating to the difference between the shareholder's required returns and the allowed return on equity.



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 still has the potential to forgo greater earnings when it chooses a more cost-effective solution. This approach is also less likely to be effective over longer time periods as utility earnings

increase over longer amortization periods. Since the adder is fixed at 4%, it will provide earnings that are comparatively better for short-lived service contracts than longer-lived ones. The incentive also provides no means of sharing the savings of an avoided expenditure. On the plus side, the incentive is flexible and can be easily applied to service expenses that are paid as they are used rather than paid in advance.

CONCLUSION

States are exploring a number of methods to help utilities efficiently optimize their operating and capital expenditures and deliver better value to customers. Regulators have many options for leveling the playing field between capital- and service-based solutions and can select an option that best meets their policy goals. 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. However, there is much more value that can be gained if regulation is designed to leverage services to their full potential. Mechanisms that allow earnings on periodic payments, and not just pre-paid contracts, allow utilities to utilize the flexibility of service solutions. Some solutions, like cloud computing, can provide additional capacity on demand with the utility charged based on actual usage. This allows for potential cost savings to customers compared to solutions that are pre-paid where the service quantity

must be estimated in advance. Shared-savings can also be employed to achieve greater cost reductions.

If these regulatory reforms function 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. Leveling the playing field for service-based solutions can also help make some regulatory proceedings less contentious.

AEE Institute's in-depth paper that includes modeling and analysis of these options can be found https://info.aee.net/aee_institute_utility_report at:



ENDNOTES

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

⁴ These costs are also interchangeably referred to as operations and maintenance (“O&M”), operating expenses, and opex.

⁵ National Association of Regulatory Utility Commissioner’s Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements, adopted November 16, 2016. See: <https://pubs.naruc.org/pub.cfm?id=2E54C6FF-FEE9-5368-21AB-638C00554476>

⁶ 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.

⁷ This concept is explained in much greater detail in a paper published by America’s Power Plan. It is recommended reading for anyone interested in greater detail the role of return on equity and cost of equity in creating value for shareholders. See: You Get What You Pay For: Moving Toward Value in Utility Compensation. By Steve Kihm, Ron Lehr, Sonia Aggarwal, and Edward Burgess. Available at: <http://americaspowerplan.com/wp-content/uploads/2016/07/CostValue-Part1-Revenue.pdf>

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

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.

