Full Value Tariff Design and Retail Rate Choices

Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service

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Energy+Environmental Economics

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Executive Summary

ES.1 Introduction

Traditionally, electric retail rates have been relatively simple, especially for mass market residential and small commercial customers. That simplicity, however, masks the more complex variations in the true underlying costs of the electrical network or grid, which limits opportunities for customers and new distributed energy resource (DER) technologies to actively participate in managing these costs. Through its Reforming the Energy Vision (REV) Proceeding, New York State has the opportunity to introduce innovations to the electric pricing options currently offered to customers. These innovations can **unlock the '<u>full value</u>'** of distributed resources to achieve the goal of expanding customer choice and opportunities for a range of technologies that can provide grid services and lower overall network costs.

'Full value'[1] is defined as the sum of the time-variant and area-specific <u>avoidable cost</u> components of DERs and load changes that are on the margin and currently monetized in electric retail rates. These components include local (distribution and sub-transmission) and system (ICAP[2]) capacity values plus zonal or nodal energy pricing (LBMPs[3]) plus the applicable energy losses. Full value may also take into consideration currently non-monetized components like environmental, health, or resiliency externalities. The fundamental approach to achieve the goal of enabling customer choice and encouraging high-value DERs is to develop a tariff that

[1] This definition of 'full value' is consistent with how the Reforming the Energy Vision (REV) Track 2 whitepaper defines "LMP + D". See **http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b48954621-2BE8-40A8-903E-41D2AD268798%7d** for more details.
[2] The New York Independent System Operator (NYISO) Installed Capacity (ICAP) market is based on the obligation placed on load serving entities (LSEs) to procure ICAP to meet minimum capacity requirements. See **http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp**
[3] This represents NYISO locational based marginal prices. See: **http://www.nyiso.com/public/markets_operations/market_data/maps/index.jsp**

prices customer loads and compensates distributed generation at the grid's 'full value', while simultaneously recovering the costs of the grid fairly. In this study, we propose a practical 'full value' tariff (FVT) as contemplated in the REV Track 2 White Paper released on July 28, 2015[4] that can achieve this goal, and we explore transition paths that can be used for its implementation.

Using pricing to shape customer behavior is not a new concept. However, absent the ability of customers to effectively respond to dynamic prices, changing prices is ineffective. Coincident with the rapid deployment and evolution of technologies such as distributed solar photovoltaics (PV) has been the introduction of information and control technologies that have advanced at a pace that few would have predicted. New technologies such as internet-connected smart thermostats, battery and thermal energy storage, controlled charging of electric vehicles (EVs), and energy efficiency (EE) measures of many types present the opportunity to transition towards electric retail rates and tariff designs that, although more complex, are more reflective of the 'full value' and underlying marginal costs of the grid. This basis is because customers' loads now have the ability to intelligently and autonomously use the electricity grid in a manner that can potentially help achieve the REV goals of:

+ Market animation and leverage of customer or third-party contributions to the grid.
+ System wide efficiency.
+ Fuel and resource diversity.
+ System reliability and resiliency.
+ Reduction of carbon emissions.
+ Enhanced customer knowledge and tools that will support effective management of the total energy bill.

[4] **http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b48954621-2BE8-40A8-903E-41D2AD268798%7d**

This study specifically builds upon the REV Track 2 White Paper, which among other things describes a general approach and the key considerations in rate design. This study provides specific proposals for two implementation paths of a FVT, a **gradual transition** and a **rapid transition**. This study also highlights the pros and cons of each pathway. The primary difference between the paths is based on how rapidly the 'full value' marginal cost-based dynamic prices are introduced to customers, which can be driven by factors like the evolution of DER technologies, customer acceptance or new business model formation around 'full value' dynamic rates, and the timing of installing advanced metering infrastructure (AMI) or 'smart meters' statewide.

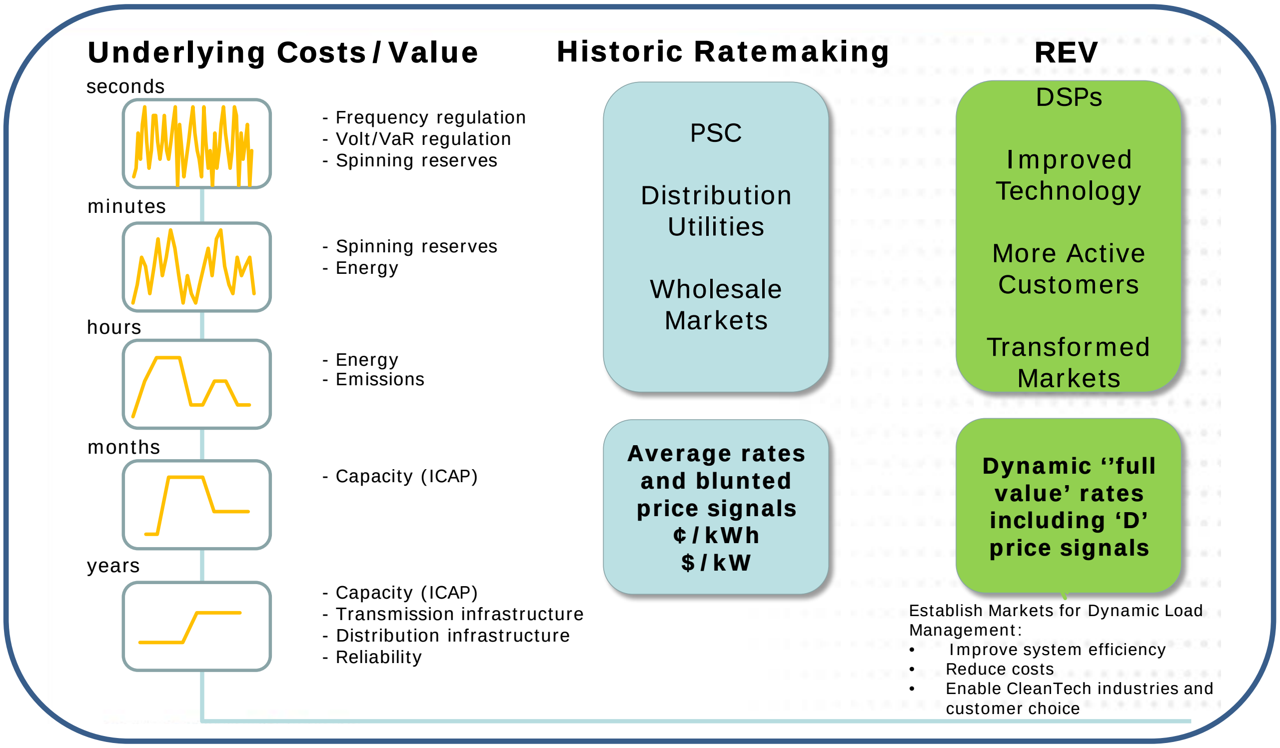
The Track 2 White Paper articulates key considerations for REV rate reforms and innovations. The rate options presented in this study build upon those considerations, which are summarized in **Chapter 1**. Broadly speaking, the retail pricing changes or REV rate reforms proposed in this study are designed to achieve the following goals.

<u>Goals of the full value tariff:</u>

+ More accurately compensate customer and third party contributions to managing the grid.
+ Collect the utility embedded[5] costs equitably and efficiently.
+ Increase competition for distribution services.
+ Lower customer costs through more efficient use of the distribution system.

[5] These are the utility costs associated with the building and maintenance of the existing electrical grid that are 'sunk', i.e. have already been spent, that then need to be collected from all customers in return for access to the grid or network.

Figure 1: One of the ways to achieve the REV transformation is to better communicate and align the fundamental underlying costs of the electric grid with the price and compensation signals sent to customers and DER technology providers or aggregators. Sending signals that better reflect the actual value to the grid can lead to market driven responses that can reduce costs and increase net economic benefits. Historically, these dynamic cost signals or sources of value have been averaged due to issues with customer education, equity, and the lack of enabling technologies. However, this is a paradigm that can change under REV.



ES.2 Unlocking the 'Distribution Value' of DERs

One of the crux issues in developing a FVT is translating the capital and operating expense decisions of the monopoly distribution utility into prices 'to beat' in order to incent competitive market responses. As distribution utilities will remain New York State Public Service Commission (PSC) regulated monopolies, utility existing and planned expenditures will be used to set 'full value' prices. In order for non-utility market-based alternatives to provide, avoid, or defer utility services and investments, the REV reforms need to provide the correct prices to incent their adoption when economic. This approach is one way to **unlock the 'distribution value' of DERs**, where 'distribution' represents the potentially avoidable sub-zonal transmission and distribution level capital costs of the utility.

Chapter 2 describes in detail one approach to unlocking this 'distribution value' and implementing the dynamic sub-zonal transmission and distribution pricing signals that would be included in the proposed FVT. The chapter focuses on the core monopoly distribution utility cost components of sub-zonal transmission and distribution capacity and energy losses. Distribution loads can provide and should be compensated for additional services such as a reduction in operating expenses along with voltage and reactive power (VaR) support. However, the overall value to the grid of these additional services is relatively low given the additional cost and complexity to implement them. **We specifically propose to unlock the 'distribution value' of DERs in the near-term by linking the costs of future utility grid expansion to area and time-differentiated prices or incentives through our proposed FVT.**

The February 26, 2015 Order "Adopting Regulatory Policy Framework and Implementation Plan" in the REV Proceeding ordered utilities to file Distribution System Implementation Plans (DSIPs) to identify opportunities to avoid traditional distribution investments with DER alternatives[6]. It is expected that these DSIPs will assess each defined distribution and sub-zonal transmission area for projected future capacity shortfalls and potentially identify least-cost projects to increase capacity if an overload is forecasted. The data underlying these plans would provide the basis to construct a forward looking marginal cost ($/kW-year) for each area linked to the utility's capital budget for the next increment of capacity by area. In the near-term, these prices can form the basis for area-specific demand response (DR) programs, targeted credits for peak load reduction, utility procurements for local area capacity resources, and/or voluntary area-specific variable pricing programs.

The DSIP process would be used to identify potentially avoidable capital projects and use these cost estimates to set marginal costs of sub-zonal transmission and distribution capacity, on an annual forward-looking basis, to be included as a component of the proposed dynamic FVT.

[6] Additional guidance on the DSIPs was provided on October 15, 2015. See: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF3793BB0-0F01-4144-BA94-01D5CFAC6B63%7d.

Each day, day-ahead forecasted *local* area load levels would be used to set hourly prices using pre-defined and transparent allocation methodologies and tariff rules. These prices would include price adjustment mechanisms that reflect changing values based on load and DER response, which could be based on the variance between the day-ahead and real-time load levels. By explicitly linking the costs of capacity by location, areas with relatively expensive upgrades will receive relatively high prices during peak load periods. This will both increase the economic opportunities for market-based alternatives and expose the utility's capital expenditures to competition from DER technologies. In exchange for being charged the higher variable prices, customers in the constrained areas would receive upfront bill credits. The area-specific bill credits and the higher area-specific dynamic prices are designed such that the average customer's overall bill in the area would not change, but load shifting, self-generation, and other types of DERs would provide an opportunity for bill savings. The average customer in both locally constrained and unconstrained areas would not on average pay more for service overall, but all participating customers in the local area would have the opportunity to reduce consumption or provide net injections onto to the grid during local and system congested periods.

The FVT is not the only tool to unlock the 'distribution value' of DERs. The DSIP driven procurements of DERs for potentially multi-year local area capacity commitments can and should be done on top of sending the proposed 'distribution' dynamic price. The DSIP process will most likely be akin to traditional planning exercises in which the distribution utility has experience, while the goal of unlocking the 'distribution value' through dynamic prices is to animate the market to provide alternatives to traditional utility planning driven investments.

ES.3 The Fundamental 'Economic Rate'

Chapter 3 and the **Appendix** to this study combine the marginal cost based prices of 'distribution value' with the other marginal costs of the bulk electric system and an idealized allocation of embedded costs based on cost causation principles, to describe a marginal cost based fundamental 'economic rate'. This fundamental cost causation rate is constructed in three parts, which is parallel to the 'three-part' rate structure described in the Track 2 White Paper.

The three parts include:

(1) **Customer charge** ($/customer) - embedded costs and expenses associated with serving the customer such as the meter, meter servicing and customer billing

(2) **Demand charge** ($/kW of coincident and non-coincident peak loads)[7] - embedded costs based on a customer's use of the existing distribution, sub-transmission, transmission, any remaining utility-owned generation assets of the grid, and regulatory balancing accounts, adders, and true-ups

(3) **Marginal costs** ($/kWh)[8] - forward looking marginal or avoidable costs of serving customer load, including avoidable zonal hourly energy costs and losses, avoidable delivery capacity and generation capacity costs during peak periods, and any avoidable merchant function charges

A fundamental economic rate would therefore provide hourly prices to customers that reflect the marginal cost of service and allocate the embedded[9] costs of the grid based on customer connection and customer grid use. In this framework, customers can make efficient consumption and production decisions that would not cause uneconomic bypass, cross-subsidization, or welfare losses. The fundamental 'economic rate' (shown in Figure 2) is then used as one guidepost in developing the proposed FVT, which has a similar three-part structure

[7] Demand charges are defined by a customer's share or usage during the peak demands on the various assets in the electrical network on a cost causation basis. In theory, a fundamental economic rate design would charge customers for their share of peak demands on each piece of network equipment (transmission substation, sub-transmission circuits, distribution transformers, distribution feeders, secondary lines, low voltage transformers, tap lines, etc.)

[8] Energy prices would be the marginal cost of energy (the locational-based marginal prices) plus losses, and could include the avoidable generation, transmission, and distribution marginal capital and operating costs allocated to the peak demand hour(s) on the respective systems that are driving the need for these expenditures. Alternatively, the marginal capacity costs could be priced as demand charges coincident with the timing of the peak hour(s) on the various distribution, sub-transmission, and bulk electrical systems. The marginal cost prices could also include energy price adder(s) for externalities or non-monetized societal costs. The focus of the marginal cost prices in the fundamental economic rate would be to provide customers with clear price signals that allow the customers to make consumption decisions based on actual marginal cost impacts.

[9] The marginal cost prices do not include the costs for prior utility investments, nor do they include the costs for utility expenses such as operations and maintenance. Therefore, the fundamental economic rate would need additional components to allow the utilities a fair opportunity to collect any difference between their revenue requirements and the revenues from pure marginal cost pricing (whether including or excluding externality costs). We refer to this difference as the residual embedded costs. For the pricing of residual embedded costs, the focus would be the fair or equitable sharing of the costs based on how each customer utilizes the grid or network.

based on the fundamental economics, but it also includes necessary trade-offs and design choices needed for actual implementation.

Figure 2: Fundamental Economic Rate[10]. The costs that need to be collected from and signaled to customers in electric retail rates and DER compensation mechanisms include both forward looking avoidable or marginal costs and embedded costs, both of which are equally important and are reflected in the fundamental three-part economic rate formulation. Marginal costs should signal the value of a change in consumption or production, while the total bill should collect the embedded costs.

	Cost Component	Description	Estimated Range
Part 1: ***Customer Charge*** *(Embedded Costs)*	Customer Charge	Costs of meter, billing, etc.	$5-$20 / customer-mo
Part 2: ***Demand Charge*** *(Embedded Costs)*	Transmission / Sub-Transmission	Historical costs to be recovered	~$1.0-$5.0 / kW
	Distribution	Historical costs to be recovered	~$1.0-$15.0 / kW
	Other	Other historical, budget driven, or miscellaneous costs to be recovered	~0.5-4.0 ¢ / kWh
Part 3: ***Marginal Costs*** *(Avoidable Costs)*	Energy	Forecast LBMP values and includes monetized carbon, SO2 and Nox costs plus generation marginal losses along with each utilities' merchant function charges	~5-7 ¢ / kWh
	Losses	T&D losses incurred	~0.5-1.0 ¢ / kWh
	Ancillaries	Forecast frequency regulation, reactive power, black start, and spinning / non-spinning reserves costs	~0.5-1.5 ¢ / kWh
	Generation	Forecast ICAP values	~2-3 ¢ / kWh
	Transmission	Congestion element in the LBMP and ICAP values	N / A
	Sub-Transmission	Deferral / avoided capacity cost value (Could be based on targeted 'hotspot' geographic value in locally constrained areas)	Locational, ~0.0-4.0 ¢ / kWh
	Distribution	(Could be based on targeted 'hotspot' geographic value)	
	Customer Charge	Forecast customer cost changes, i.e. for billing costs	~0.0-0.5 ¢ / kWh
	Public Purpose Charges	System Benefit Charges and Renewable Energy Portfolio Charges	~0.5 ¢ / kWh
	Health, CO_2, Resiliency, etc.	Externalities to be potentially internalized	~0.0-5.0 ¢ / kWh

ES.4 Proposed Full Value Tariff

Chapter 3 then goes on to describe our proposed FVT that maintains the principles and theoretical underpinnings of the fundamental 'economic rate' while simplifying its structure for implementation. Like the fundamental economic rate from which it is derived, the FVT is

[10] The estimated values and ranges of the cost components are based on E3 analysis, historical values, and high-level estimates in order to provide general information on these cost components that ranges across the New York utilities.

comprised of three parts: a ***customer charge***, a size-based ***network subscription charge***, and a varying kWh ***dynamic price***. The dynamic price is a volumetric charge ($/kWh) that varies by location and time, i.e. real-time pricing (RTP), to better reflect the marginal or avoidable costs of serving customer load including the wholesale costs of energy (zonal or nodal), losses, generation capacity, and transmission capacity. The dynamic price also includes the 'distribution value' defined as sub-zonal transmission and distribution marginal (i.e. avoidable) costs by area and time. These pecuniary costs change when a customer changes consumption or generation patterns. In addition, we develop a version of our full value tariff that also includes societal non-monetized costs of energy consumption, such as CO_2 emissions and health impacts from criteria pollutants in the dynamic price. When the societal costs or externalities of energy use are included (FVT+'E'), the tariff signals the societal optimal consumption decision for customers. **It is important to note that in both the proposed FVTs, any additional revenue above direct costs collected by the distribution utility through the dynamic price (e.g. from avoided distribution capacity or externality price signals) would be offset by a lower network subscription charge such that the total revenue collected in customer bills remains the same in either version of the tariff. In other words revenue neutrality is maintained.**

Providing a 'distribution' dynamic price in a FVT is analogous to the original utility industry restructuring in the 1990s, which made generation and transmission prices of energy and capacity available to retail customers through direct access in New York State. Currently, 23% of residential, 36% of small non-residential, and 75% of large non-residential customers are direct retail access customers served by a broad range of energy service companies (ESCOs). The dynamic price in the FVT will make the distribution utility sub-zonal transmission and distribution costs available as prices so that retail customers that can respond can be credited for not using the sub-zonal transmission and distribution services. In the same way that ESCOs provide pricing and risk mitigation for generation and transmission system services to retail customers today, ESCOs along with DER aggregators or third party owners would likely play a similar key role in sub-zonal delivery services under the proposed FVT[11].

[11] For example, an ESCO or third party DER aggregator/owner could offer a customer a fixed price contract for electricity, while managing the underlying volatility of the sub-zonal prices similar to how they provide this service for wholesale system energy and capacity prices.

The customer charge and the size-based network subscription charge collect the customer-related costs and the residual embedded costs of the network, respectively. Customer-related costs are associated with a customer account such as billing and meter costs. The residual embedded costs of the network are the inelastic costs that do not change with consumption and are allocated to customers based on their share of network use of grid assets. The proposed FVT uses a simplified measure of size to determine customer network usage for mass market (non-demand metered residential and small commercial) customers based on a customer's historical maximum monthly average demand from the previous 12-months. For larger customers that are demand metered, size is determined by a customer's subscribed peak demand. Over time, the form of the size-based network subscription charge can be modified to be more reflective of customer's coincident demand on the network assets. Further modification of network subscription charges could also include the concept of subscribed capacity, i.e. 'contract demand[12]' of the network to provide further cost containment benefits as the REV transformation evolves and customers become more accustomed to size-based charges for access to the network.

Ultimately, the proposed FVT will accomplish the following:

- Transitions current retail pricing and DER compensation mechanisms to a more fundamentally sound economic rate;
- Balances issues of customer equity, understandability, and existing rate design choices; and,
- Provides an opportunity for various types of DERs and changes in customer behavior to be compensated for value provided in a fair and technology neutral manner.

As an example, **Chapter 3** also includes illustrative residential FVT rates for a Downstate (Consolidated Edison) and an Upstate (National Grid) utility based on their most recent embedded cost of service (ECOS) and marginal cost of service (MCOS) studies as well as their

[12] This is similar to New York's current standby rate design that has contract demand and daily-as-used demand options such as Consolidated Edison's SC14 tariff: **http://www.coned.com/documents/ra/ra-sc14.pdf**

historical wholesale costs and market supply charges (MSCs). Illustrative total bills are developed in **Chapter 5**. These illustrative rates and total bills show that a customer's average monthly bill under the proposed FVT is <u>by design</u> similar to their bill today. However, the bill could be lower if the customer consumes less energy during the peak periods, or higher if the customer responds to the lower off-peak price in a way that more than offsets any bill reduction during the peak period. Numerous different options can be used for 'revenue neutrality' such that the total bills of customers under existing rates are approximately equal to their total bills under a new rate, assuming no change in consumption patterns. These options can be tailored to achieve revenue neutrality for an average customer in a class or for a customer in various load strata or usage levels. Further, there could be a temporary guarantee (e.g. 1- to 2-years, with a partial phase out) to customers that participates in the FVT that they will receive a credit at the end of the year to 'guarantee' the lower of their bill on the existing rate or their bill on the FVT as a transition mechanism.

To evaluate the effects of a FVT, a New York-specific '*smart home'* model was developed to evaluate customer behavior and the value proposition of key DER technologies that can potentially respond to dynamic prices sent through retail rates such as those under existing default rates, existing time-of-use (TOU) rates, and the proposed FVTs or 'smart' rates that are more area- and time-specific. Solar PV, air conditioning energy efficiency, customer conservation[13], smart heating/cooling, and smart charging of electric vehicles are evaluated. Below, Figure 3 shows the bill savings for a typical customer for several key DERs for both a high 'distribution' value location and a zero value location. A customer on the existing rates receives no value for smart heating/cooling, battery storage, or smart charging of vehicles. If the customer could switch to the FVT or 'smart' rate, there would be significant bill savings across the spectrum for a range of DER technologies[14]. Lastly, it is important to note that under the proposed FVT certain technologies or customer behaviors may continue to be compensated at

[13] The 'conservation' value is based on assumptions of customer price demand elasticity and minimum consumption patterns, which results in increased consumption at low cost hours, and decreased consumption during high cost hours.
[14] It is worth noting that while the currently offered optional TOU rate does provide a value proposition for the range of DER technologies, it can and does under or over compensate certain technologies. In particular it overcompensates for shifts in consumption in the winter months for electric heat pump heating, battery storage, and smart EV charging.

or above their fundamental value to the grid[15], which is an explicit design choice in order for the FVT to be both practically implementable and to encourage more societally efficient outcomes.

Figure 3: 'Smart home' technologies can realize significant customer savings as prices become more value-based, i.e. time-variant and area-specific, under the FVT. Customer bill savings from both dynamic pricing and network subscription charge reductions from dispatchable[16] and non-dispatchable technologies are shown for both a high local value location, i.e. in an transmission and distribution (T&D) constrained zone, and zero value location, i.e. non-constrained zone, for both Consolidated Edison and National Grid.

E3's Smart Home Model

E3's Smart Home model simulates the customer and utility system benefits of controllable flexible loads under any user defined retail rate price scheme like the FVT including TOU, tiers, subscription charges, and real-time pricing

A 2,500 square foot, 3-bedroom New York specific home is modeled with a generic home energy control device that:

- Sends and receives data signals to/from the electricity grid
- Learns customer preferences and behavior
- Controls electricity use and generation of home appliances

Bill savings (high local T&D value) $/year
Bill savings (zero local T&D value) $/year

	Rate Option	Solar Roof (75% Usage Offset)	A/C EE 25% Savings	Price Induced Load Shifting	Smart HVAC	Battery Storage	Smart Electric Vehicle
ConEd	Existing Rates	$1,253 / $1,253	$112 / $112	No Savings	No Savings	No Savings	No Savings
ConEd	Current Optional TOU	$1,467 / $1,467	$136 / $136	$50 / $50	$98 / $98	$357 / $357	$202 / $202
ConEd	Full Value/Smart Rate	$1,179 / $742	$146 / $93	$274 / *$(74)**	$236 / $151	$430 / $305	$141 / $133
ConEd	Full Value/Smart Rate + Societal Signal	$1,300 / $863	$142 / $89	$260 / *$(74)**	$229 / $144	$404 / $280	$123 / $122
National Grid	Existing Rates	$664 / $664	$51 / $51	No Savings	No Savings	No Savings	No Savings
National Grid	Current Optional TOU	$582 / $582	$44 / $44	$10 / $10	$8 / $8	$31 / $31	$7 / $7
National Grid	Full Value/Smart Rate	$587 / $425	$51 / $33	$48 / $12	$156 / $50	$350 / $144	$192 / $48
National Grid	Full Value/Smart Rate + Societal Signal	$723 / $562	$61 / $43	$37 / $24	$149 / $43	$328/ $122	$184 / $39

*Price elasticity results in bill increases because of increased consumption due to lower prices.

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[15] More information on this topic can be found in Figure 27, which is a table that presents the amount of DER compensation in the form of bill savings under existing rates and the FVT against the fundamental grid value of the DER in percentage terms. For example, if bill savings for a DER is $150 and the underlying grid value of that DER is $100, then the percent of bill savings to value equals 150%.

[16] In the formulation of the FVT with a societal adder, a flat ¢/kWh societal price signal is added on top of the dynamic prices. For load shifting or dispatchable technologies like 'smart' thermostats, battery storage, and 'smart' electric vehicle charging, the FVT with a societal adder may result in bill savings less than what is achieved under a FVT with no societal adder. This is because load shifting is driven by the relative difference between prices in high vs. low cost hours, i.e. peak vs. off-peak ratios, rather than the absolute price levels.

ES.5 Transition Paths to the Full Value Tariff

A FVT will require wide stakeholder engagement and substantial time and effort to implement as a default tariff, including deployment of advanced metering infrastructure (AMI). In **Chapter 4**, near-term retail rate reforms that could be implemented as initial steps along either ***gradual*** or ***rapid*** transition paths to a default FVT are proposed. These transition paths are described in greater detail in **Chapter 5**. These near-term reforms can help incubate new technology, support existing market transformation, increase the capability and experience of utilities in valuing local areas of the grid, gauge interest in ESCO or aggregator products to help customers manage 'distribution' price volatility, and build all parties' experience with 'smarter' rates more reflective of 'full value'. Near term changes also minimize uneconomic customer investment decisions that only <u>appear</u> economic under existing retail prices.

These immediate reforms could include:

1. Offering *optional* **'smart home'** and **'smart business'** tariffs or rates that are modeled from the 'full value' rate to test the market for load participation and encourage technology development and adoption; An expansion of *optional* targeted and local demand response and peak time capacity rebate programs that reflect the 'distribution value' of DERs described in **Chapter 2**, and;
2. Reforming the existing *optional* TOU rates so that the price differentials better reflect the forecasted differences in underlying marginal costs, while continuing to be revenue neutral with default rate options for residential customers[17].

Together, these reforms could improve the economic efficiency of the retail dynamic price, give the distribution utilities experience in local grid planning and targeted DER, and provide a market for a range of load management technologies through the optional 'smart' rates that currently have little ability to receive compensation.

The utilities can continue to take advantage of greater localization of peak load reduction measures targeted toward capacity-constrained areas in the distribution system and continue

[17] Revenue neutral is defined such that a customer with the average class profile would pay the same annual bill under the TOU rate as the default rate.

to integrate DERs into their transmission and distribution planning. These efforts will likely be proposed in the upcoming DSIPs. Offering optional 'smart home' and 'smart business' rates in the near-term would also allow the PSC to gauge ESCO and DER aggregator capabilities and efficacy in providing services to help customers manage the full value dynamic prices.

Chapter 4 also describes potential updates to the net energy metering (NEM) tariff and refinements of other utility offerings like demand side procurements and demand response (DR) programs that can be implemented as a transition towards a FVT.[18] The NEM tariff is the current mass-market compensation mechanism for qualifying distributed generation, which allows customers to receive bill credits for any excess production not consumed on-site at the retail rate. NEM has successfully encouraged customers to adopt distributed generation and is transforming the New York market for distributed energy resources and distributed solar PV in particular. By the end of 2015, 500 MW of solar and 30,000 customers are expected to be participating in NEM.

The NEM tariff is directly tied to a customer's retail rate, and because existing rate designs do not vary by location, the NEM tariff does not distinguish between higher and lower value locations. In addition, NEM generally credits customers for distributed generation more than the pecuniary value of the energy and capacity it typically provides to the grid. Some have argued that this can potentially shift costs to other customers and could create equity and cost problems if uncapped. If New York distribution utilities were to implement FVTs, with dynamic prices equal to the marginal (and, thus, future avoidable) costs of the system, both the potential cost and equity problem with the current NEM tariff could be reduced and potentially resolved. If the tariff valuation is not sufficient under a FVT to reach certain clean energy policy goals, explicit incentives can be put in place to encourage adoption, without distorting the more granular dynamic marginal prices of the FVT. In the interim, additional alternatives in **Chapter 4** are considered, including continuing the NEM rate and moving valuation of grid injections or net

[18] This value-based approached for DER is articulated in an October 15, 2015 PSC Order, which on an interim basis also lifted the existing NEM caps. See: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6D51E352-B4C8-48F9-9354-2B64B14546DC%7D

exports in the direction of more marginal or avoidable cost based prices along with offering value-based credits. Value-based credits could include the social value provided by clean generation. In addition, a simpler three-part rate without the need for AMI for mass market customers could be implemented by introducing a network subscription charge <u>only</u> without dynamic pricing.

Chapter 5 then describes the **gradual** and **rapid** implementation paths to a FVT and the enabling conditions under which one would be preferred over the other. The key enabling conditions to consider with regards to the pace of the transition include the following:

- Technology development.
- Advanced metering deployment.
- The distribution utility's evolution to incorporate DER in planning, development, and operations.
- ESCO and DER aggregator evolution to offer products to manage loads and 'distribution' price volatility.
- The evolution of the underlying policy goals and decisions (NY Sun, EE, GHGs, and EV goals) that have occurred to <u>either</u> accelerate the implementation of REV or maintain a more gradual transition pace.

Specifically, the gradual path consists of implementing the near-term rate reform options such as offering optional 'smart home' and 'smart business' FVTs and potentially developing targeted demand response and local capacity credit programs to provide incentives to customers for peak load reduction. All of these changes could be realistically implemented in 12 to 18 months after a decision is reached. The biggest advantage of the gradual transition is that the vast majority of customers will be unaffected. The biggest disadvantage is that the gradual path is only an incremental improvement over the current opt-in approach of offering targeted demand response programs in a local area. Opt-in demand response programs are usually of interest to only a small fraction of customers, and require complex programmatic rules to define the customer baseline that is the basis of incentive payments. Lack of participation can be driven by poor program design, too little customer engagement, poor marketing, or other factors. If the right enabling conditions occur, New York could choose to make the necessary investment in advanced metering infrastructure and implement the FVT as the default retail rate option under the gradual path.

In the rapid path, the same near-term rate reforms would be implemented. At the same time, New York utilities would begin to deploy advanced metering infrastructure (AMI or 'smart' meters) for mass market customers, shift large commercial customers to the FVT[19] in the near-term and then implement the FVT as the default retail rate option once AMI is fully deployed.

ES.6 Conclusions

Chapter 6, which concludes the study, briefly summarizes the proposed approaches and highlights the key innovations. Key risks are highlighted, including technology development and competitiveness, the process for unlocking the 'distribution value' of DERs, the deployment of AMI, and the receptiveness of the market actors. For the case where deployment of the FVT is successful, public interest benefits are enumerated. Finally, potential FAQs that stakeholders may have on the proposal are answered.

As articulated throughout the REV Proceeding, transforming the retail rate structure to reflect an efficient economic signal would achieve a number of objectives in the public interest. The proposed FVT provides an achievable path to this goal. If successful it can:

+ Save ratepayers money by avoiding **future** expenditures in the distribution network and encouraging adoption of appropriate DER in areas of the network with high avoidable costs.
+ Increase economic activity by making low cost electricity available when it is actually low cost.
+ Provide an economic foundation that can guide a whole range of investment and operational decisions without explicitly needing to address these problems in a

[19] The full value tariff could be considered a modification or replacement of existing standby rates that would also include the local sub-zonal distribution and sub-transmission marginal price signals plus contract demand or capacity subscription.

programmatic framework. For example, 'smart charging' electric vehicles is an emerging topic that a FVT can support without any changes.

+ Create a vibrant market for technology by providing a compensation mechanism based on value and removing programmatic, regulatory based rules and baselines for participation.
+ Provide a specific lever for the State to efficiently address climate change, local criteria emissions, and other externalities.

As with any rate design, the path toward transition is critical for implementation. The proposed FVT is designed to accentuate positive and limit negative consequences for the public and key stakeholders. These stakeholders include New York ratepayers foremost, but also distribution utilities, environmental and local interests, technology innovators, and ESCOs.

Key FAQs:

Q: What has changed with regards to implementing mass market real time pricing (RTP)?

A: Technology has made RTP possible. This includes control technology for appliances and energy management systems, data and information on distribution system operations, and lower cost and more capable AMI systems.

Q: Why transition toward default rates that reflect area- and time-specific costs, rather than optional credits?

A: Optional credits either create a large risk of free riders, or require defining a customer baseline which limits participation and adds complexity. For programs that operate a few times per year, a simple baseline is implementable, but for load shifting every day, establishing 'normal' operations in a baseline is problematic. In addition, broad participation in a default rate allows many small load changes to add up to meaningful impacts.

Q: **Why is it important to collect embedded costs with network subscription charges?**

A: Mispriced components lead to inefficient investment and operation decisions by customers. Without a size-based access charge to recover residual embedded costs, higher volumetric rates are required which charge customers more than the marginal costs for energy consumption. Access charges reduce uneconomic bypass and lessens social welfare loss.

An access charge reduces the risks of recovering residual utility embedded costs, provides greater revenue stability on existing assets for utilities, limits uneconomic bypass, and should allow utilities to achieve lower financing costs of the network on behalf of all ratepayers. This strategy could enable the evolution of different utility business models, such as separating the utility into an independent distribution system operator that plans and operates the grid and an asset company that uses asset-backed financing and a fixed revenue stream based on the network subscription charge to finance and maintain the network at a lower cost.

Q: **Does the proposed FVT eliminate the incentive for investment in energy efficiency for non-demand, mass-market customers?**

A: No. The varying dynamic price will provide an appropriate economic signal for changes in consumption behavior and energy efficiency. The energy efficiency that occurs during peak times will be valued more than they are with existing rates, and off-peak times less.

Secondarily, the network subscription charge is based on network usage and depending on how network usage is defined energy efficiency may reduce an individual customer's network usage and those associated costs over time.

1 Introduction

1.1 Background

Energy and Environmental Economics, Inc. (E3 or "we") was retained by the New York State Energy Research and Development Authority (NYSERDA) to conduct a study on its behalf as well as on the behalf of the Department of Public Service (DPS) to examine the design of a *full value tariff*[20] (FVT) and associated retail rate choices in the context of the Reforming the Energy Vision (REV)[21] Proceeding in New York. This process was informed by the REV Track 2 White Paper on Ratemaking and Utility Business Models[22]. A project management team consisting of key members of DPS and NYSERDA staff was formed and consulted with regarding the methodology and approach of our proposed FVT design throughout the entire study process.

1.2 Context for Retail Rate Reform and the Full Value Tariff

1.2.1 GOALS OF REFORMING THE ENERGY VISION

The REV Proceeding has articulated a number of goals:

+ Enhancing customer knowledge and tools that will support effective management of the total energy bill;

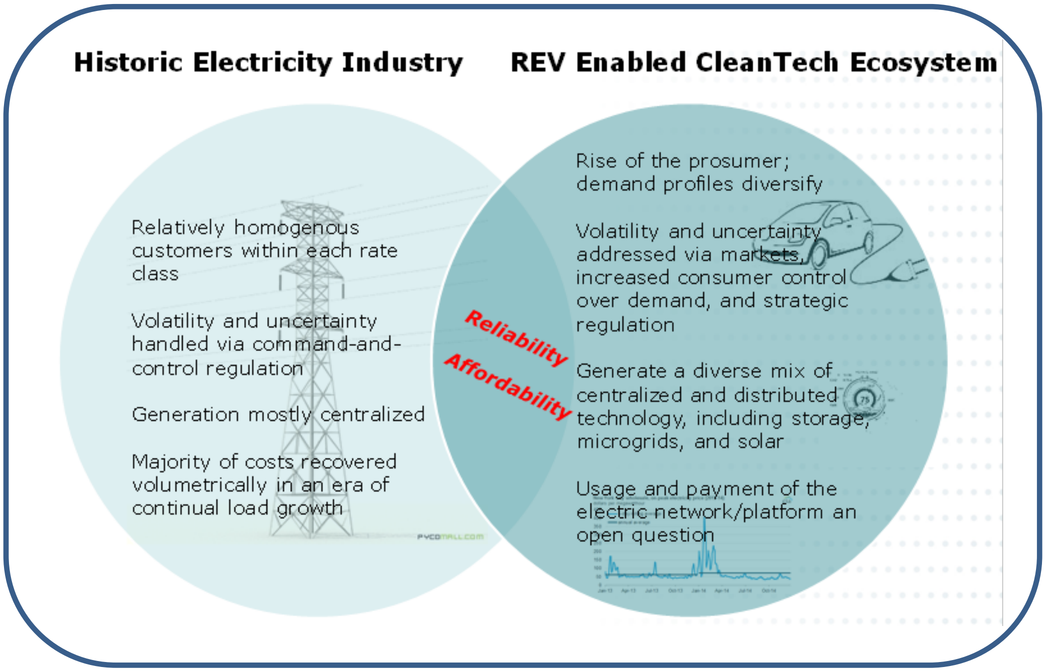
[20] A 'full value' tariff or FVT is defined as a dynamic tariff based on the area and time differentiated underlying costs of the electric system to create price signals that vary by time and location for retail load and distributed energy resources to provide 'full' value to the system both on a local and aggregate level.

[21] http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

[22] This paper describes the limitations in current ratemaking practices in the context of REV, describes the direction of comprehensive ratemaking and business model reforms, and makes recommendations for near-term reforms where possible. The scope of this white paper is limited to ratemaking issues, including the utility business model and earnings opportunities, the ratemaking process, and rate design. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b48954621-2BE8-40A8-903E-41D2AD268798%7d

+ Animating the market and leveraging customer contributions;
+ System wide efficiency;
+ Fuel and resource diversity;
+ System reliability and resiliency; and,
+ Reduction of carbon emissions.

Figure 3: The goals of REV are ambitious and could lead to wholesale market transformation and greater customer choice.



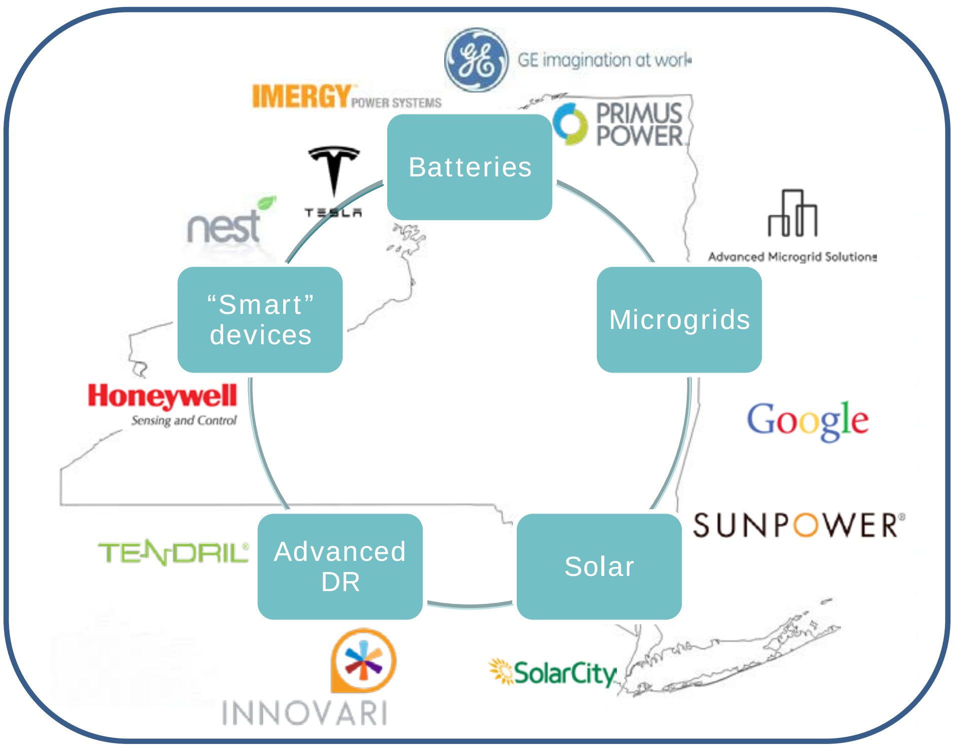
We believe that one of the core aspects of REV is to reform retail rates to better reflect dynamic 'value' based pricing, which is the focus of this study. It is important to note that there are a number of other parallel efforts within the REV Proceeding of which this is one. Others include developing models for nodal and sub-nodal energy pricing that provide more granular and potentially distribution level locational marginal prices[23], developing a pricing platform for transactions, and defining the role and business models of the distribution utilities and the Distributed System Platforms (DSPs).

[23] In the REV Track Whitepaper this is referred to as LMP + D. See http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b48954621-2BE8-40A8-903E-41D2AD268798%7d for more information.

We believe that providing a dynamic value-based price to loads, customers, and energy service companies (ESCOs) or aggregators will support the REV goals by:

+ Increasing the participation of loads and distributed energy resources or DERs in the management of the grid by compensating DER for services they provide at their actual full value;
+ Unlocking the 'distribution value' of DERs by introducing competition, revealing costs, and enabling technology to provide distribution level benefits, and;
+ Creating a more resilient and efficient grid with lower costs to electricity customers.

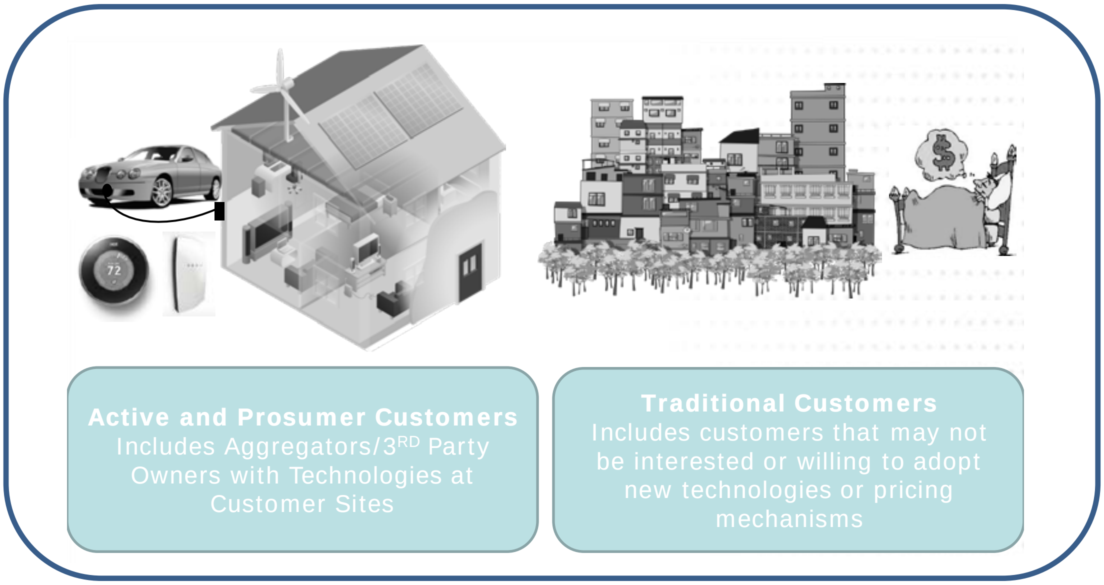
Figure 4: What does the future look like? Is it a REV enabled market driven Clean Technology (CleanTech) ecosystem?



1.2.2 ADVANCING TECHNOLOGY

Offering a dynamic value-based price is only useful to the extent that customers and loads can react in response. Fortunately, a broad range of grid interactive technologies are becoming increasingly available at lower prices. Adopting dynamic value-based pricing can further accelerate these products into the marketplace. The range of customer-side technologies that can respond to dynamic value-based tariffs includes solar roofs with smart inverters, advanced home automation, more sophisticated energy management systems for buildings, battery storage, thermal storage, and smart electric vehicle charging among others.

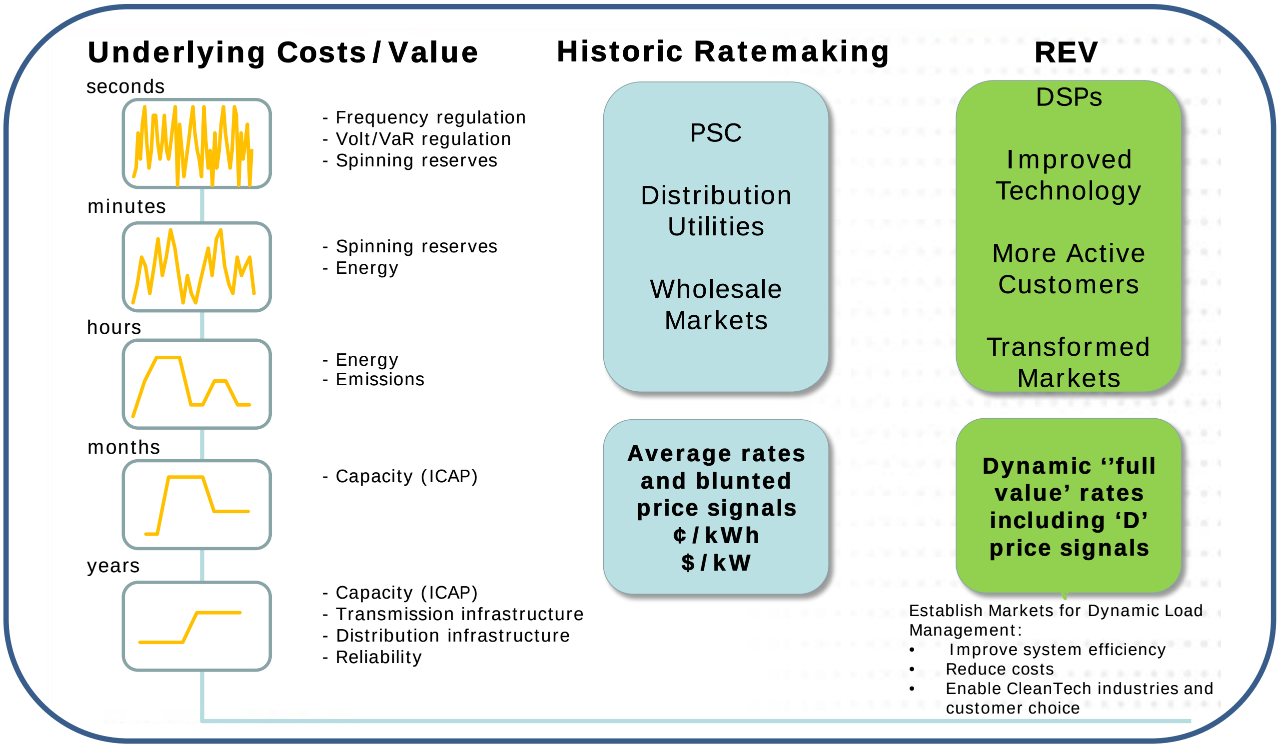
Figure 5: The electric network is evolving to a platform where there will be many types of customers with the potential for a greater diversity of transactions as compared to the traditional unidirectional utility supply of inelastic load in return for customer payments based on flat volumetric rates.



1.2.3 SHORTCOMINGS OF TODAY'S RETAIL RATES

Today's retail rates are generally designed to be simple and fair, but they are inadequate for achieving the REV goals of a cleaner, more efficient grid. Most notably, they lack a value-based pricing mechanism that encourages economically efficient behavior and compensates for load response and self-generation in the highest value locations at the highest value times. This is because today's retail rates include the recovery of the fixed or embedded costs of the grid that are 'sunk' through a per kilowatt-hour (kWh) charge and by averaging costs by area and time. This results in potentially inappropriate cost shifts for self-generation when coupled with net energy metering (NEM). In other words, economically inefficient outcomes may occur if the value of load response or self-generation cannot be communicated and compensated appropriately. Furthermore, creating viable business models around multiple technologies that can provide value to the system becomes difficult without a mechanism for effective monetization.

Figure 6: One of the ways to achieve the REV transformation is to better align the fundamental underlying avoidable costs of the electric grid with the price and compensation signals sent to customers and DER technology providers or aggregators. This can lead to market driven responses that can reduce costs and increase net economic benefits. Historically these dynamic cost signals or sources of value have been averaged due to issues with customer education, equity, and the lack of enabling technologies, a paradigm that can change under REV.



We believe that the current retail prices and DER compensation mechanisms do not appropriately reflect full value, especially with regards to the locational 'distribution value' of DERs or their societal externalities.

In particular, the two main types of potential compensation mechanisms for DER generation: 1) traditional utility buy-back contracts[24]; and 2) NEM[25] retail rate credits have several issues.

[24] Buy-back contracts are meant to compensate larger, more traditional generators at hourly wholesale energy prices and do not include specific value for location on the distribution grid or value for any environmental benefits.

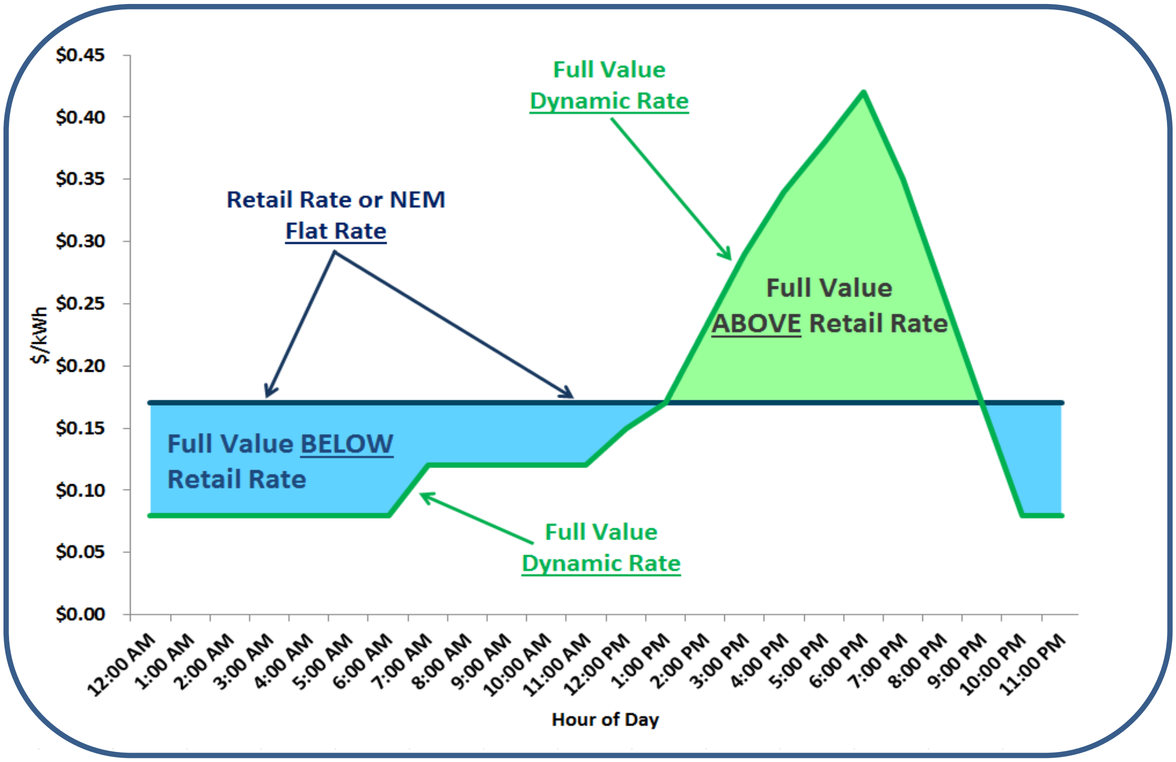
+ Both of these mechanisms are at best imperfect tools that potentially over compensate certain DER technologies and under compensate or provide no compensation for other types of DER technologies, most notably load shifting and storage technologies.
    - Neither of these mechanisms is structured to provide compensation for services such as load shifting and conservation behavior or storage and 'smart' electric vehicle (EV) charging investments for the vast majority of customers.
+ NEM is a relatively blunt pricing instrument that currently does not differ by time, location, or technology and may inappropriately shift costs to non-participating ratepayers due to the underlying electric retail rate design tied to NEM compensation[26].
    - NEM may be appropriate to promote clean DER technologies from a state of near-zero penetration due to its simplicity and the need to incent adoptions, but as the Track 2 White Paper states, strategies like NEM *"may not be optimal for DER that is widespread and mainstream and will need to rely on consistent and accepted valuation methods."*

As can be seen in the figure below, there is a clear gap in any compensation mechanism that does not reflect the dynamic spatial and temporal value of DERs or changes in customer consumption. Such is the case with NEM, which is tied to a non-dynamic flat kWh retail rate.

[25]Net energy metering (NEM) provides credits on net injections to the grid, which are based on the host customer's retail rate and is not based on any specific value (locational or otherwise) provided by the resource to the grid, but rather tied to the overall rate design of that customer's class or the opt-in rate the customer may be on, if applicable.

[26] The Track 2 whitepaper refers to this type of issue as follows: "*If the monthly bill reduction from a DER investment depends in part on avoiding a share of distribution costs, then two types of uneconomic bypass may occur. On one hand, customers who install DG and continue using the grid may avoid their appropriate share of system costs, leaving other customers to pay the balance. The other form of bypass, however, is the exact opposite. If fixed customer charges are so high that a customer can only avoid delivery charges by exiting the system altogether, then any share of distribution charges that the customer might have been willing to pay in order to remain connected is lost".*

Figure 7: There is a 'value gap' between the dynamic value that DERs and consumption changes can provide to the grid vs. what that value is currently compensated at due to the underlying retail rate design and NEM compensation mechanism.



1.2.4 CONCEPT OF A FULL VALUE TARIFF

We believe that more efficient retail rate options and 'full value' dynamic tariffs should lead to lower-cost and higher-valued allocation of economic resources by reducing costs and expanding net economic benefits. This study provides an approach that can achieve more value-based pricing and compensation mechanisms coupled with a fairer and more efficient recovery of the grid's embedded or fixed costs. This approach can meet New York's policy goals by identifying several low risk near-term steps and developing longer-term transition pathways to potential REV 'end states'.

To support this vision, New York will need pricing and DER compensation mechanisms[27] that can better communicate 'value' by translating fundamental electric dynamic prices (energy, ancillary

[27] These can include value-based payments, incentives, rebates, and/or credits.

services, capacity, etc.) to customers (traditional, active[28], and/or prosumers[29]) and DER technology providers (aggregators, 3rd party owners, etc.). This concept is articulated in the DPS REV Track 2 White Paper, which states that *"rather than simply allocating costs, rate design under REV should work toward enabling the reduction of total costs by appropriately signaling value. The goals of REV now call upon consideration of mechanisms that compensate customers for the benefit their DERs provide to the system".*

This study builds upon the themes and guidance articulated in the Track 2 White Paper. We develop one possible framework for new pricing and compensation mechanisms that are more 'value' based, encouraging efficient customer behavior and compensating for services that provide value to and/or lower the overall costs of the grid in both an economic and equitable manner. Specifically, according to the Track 2 White Paper *"adopting a rate design and compensation mechanism based on a more precise calculation of system value should greatly improve the proper valuation of DER. This will provide greater confidence in the market, and will make investment decisions in DER more stable and predictable."*

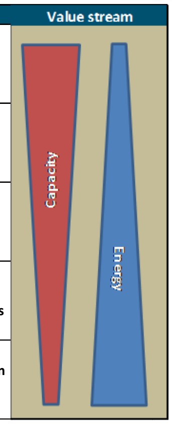
To that end, key points of these new 'value' based mechanisms are as follows:

1. They should be 'dynamic' to provide the appropriate signals to reduce load and/or increase generation during key times and at key locations;
2. They should be 'stable[30]' to provide investment signals for DER technologies and to reach certain policy goals and adoption targets.
3. They must explicitly consider and address impacts to the network's recovery of fixed costs, environmental outcomes, and other ratemaking factors including equity and fairness.

[28] These are customers that take a more active interest in their energy use and consumption decisions.
[29] These are customers that both consume and produce energy.
[30] Stable refers to being predictable in overall magnitude from year to year. Stability does not require that the rates be uniform over the entire year. Energy prices that vary hourly can still promote investments to the extent that future returns or bill savings can be forecast with some confidence.

Figure 8: DER technologies offer a diverse range of benefits (both energy and various types of capacity) that can all be potentially valued and compensated in a FVT.

Category	Primary Purpose	Timeframe
Emergency demand response	Improve reliability	Seldom, during contingency
Demand response	Reduce peak load related infrastructure construction (power plants, transfomers, substations, etc.)	<100 hours per year
Load shifting	Improved load factor, higher utilization of grid assets, potential peak load reduction	Daily, all year, or by season
Renewable distributed generation	Reduced fuel consumption and emissions, avoid infrastructure investment, etc.	Year round with seasonal, diurnal trends
Energy Efficiency	Reduced fuel consumption and emissions, avoid infrastructure investment,	During device operation (seasonal, daily, etc.)



Competing goals

DER price signals or compensation mechanisms should be 'dynamic' to provide the appropriate signals to reduce load and/or increase generation during key times

Signals should also be 'stable' to provide investment signals for DER technologies

Our proposed FVT is granular across the *Temporal*, *Locational*, and *Attribute* dimensions discussed in the Track 2 White Paper. We also evaluate whether DER investments can produce net beneficial results for both the participating customer and the system as a whole. The Track 2 White Paper states "*[t]his can be achieved by improving both the compensation for DER services provided to the grid, and recovery of grid costs properly assigned to the DER customer*". In other words, we look at designing a FVT that assigns prices to the underlying avoidable costs of the grid to communicate value. We also evaluate the financial proposition and business case of the FVT for a number of different technologies, including solar PV, smart thermostats, etc.

In this study we construct a fundamental cost-causation rate in three parts to guide our formulation of the FVT, parallel to the 'three-part' rate structure with customer 'demand' charges described in the Track 2 White Paper. This three-part structure is already in place to some extent for larger customers in New York that are demand metered, but is currently not in place for smaller mass-market customers such as residential and non-demand metered small commercial customers.

The three parts of the fundamental economic rate and our proposed FVT include:

- **Customer charge** ($/customer) = embedded costs and expenses associated with serving the customer such as the meter, meter servicing and customer billing.
- **Demand charge**[31] ($/kW of coincident and non-coincident peak loads) [32] = embedded costs based on a customer's use of the existing distribution, sub-transmission, transmission, any remaining utility-owned generation assets of the grid, and regulatory balancing accounts, adders, and true-ups.
- **Marginal costs** ($/kWh)[33] = forward looking marginal or avoidable costs of serving customer load, including avoidable zonal hourly energy costs and losses, avoidable delivery capacity and generation capacity costs during peak periods, and any avoidable merchant function charges.

Therefore, the FVT focuses on granular marginal cost based dynamic prices in order to signal the value of a change in consumption or production. The rate also keeps the existing load-serving entities whole by including rate adders to collect any residual utility embedded costs. The adders can be applied to various rate components, i.e. fixed vs. variable charges, in order to promote various policy goals. For example, putting the adders in the fixed charges would maximize economic efficiency, while putting the adders such as for societal environmental costs like carbon in the energy charges would promote certain DER adoptions and societal efficient outcomes.

[31] This is in line with the Track 2 Whitepaper which states the following: *"Because long-run distribution marginal costs are driven by coincident peak on a circuit-by-circuit basis, customers' usage at system peak provides the most accurate measure of system costs. And, unlike fixed customer charges, peak demand can be managed by customers via DR, energy efficiency, and/or DG. Therefore, the incorporation of a peak-coincident demand charge in place of some portion of the kWh and fixed customer charges is put forward here for comment and further development. As part of the proposed transition to a three-part rate (volumetric charge, demand charge, and fixed customer charge), the fixed customer charge should be formulated to reflect only the costs of distribution that do not vary with customer demand or energy consumption."*

[32] Demand charges are defined by a customer's share or usage during the peak demands on the various assets in the electrical network on a cost causation basis. In theory, a fundamental economic rate design would charge customers for their share of peak demands on each piece of network equipment (transmission substation, sub-transmission circuits, distribution transformers, distribution feeders, secondary lines, low voltage transformers, tap lines, etc.)

[33] Energy prices would be the marginal cost of energy (the locational-based marginal prices) plus losses, and could include the avoidable generation, transmission, and distribution marginal capital and operating costs allocated to the peak demand hour(s) on the respective systems that are driving the need for these expenditures. Alternatively, the marginal capacity costs could be priced as demand charges coincident with the timing of the peak hour(s) on the various distribution, sub-transmission, and bulk electrical systems. The marginal cost prices could also include energy price adder(s) for externalities or non-monetized societal costs. The focus of the marginal cost prices in the fundamental economic rate would be to provide customers with clear price signals that allow the customers to make consumption decisions based on actual marginal cost impacts.

Further, we propose that the FVT will have built-in 'circuit breakers' to control the quantity of load response and any net injections of energy into the distribution grid by DERs. This is meant to ensure that there is some form of price or quantity control as the distribution utility or DSP learns to send full value dynamic prices to incent load and customer participation in managing the grid, e.g. 'mini-demand curves' or price caps, for resources.

1.2.5 TRANSITION PATHS

We believe that the initial transition for the FVT is clear and can be implemented quickly with offering the FVT as an opt-in 'Smart Home' or 'Smart Business' rate as envisaged by the Track 2 White Paper. The FVT can then evolve and become a default tariff if the enabling conditions are achieved. These enabling conditions, which must be continually monitored to control the pace and scope of the transition, are as follows:

- Technology development;
- Advanced metering capabilities;
- DSP evolution;
- Increasing levels of customer sophistication; and,
- The achievement of the underlying policy goals.

The proposed FVT represents a longer-term 'end state' for REV. However, any transition to the 'end state' would take time and each 'end state' could also be a transition step to the next longer term 'end state'. There are a myriad of policy choices and technology developments that would need to happen to warrant a full rate reform. Therefore, we describe a number of potential low risk transition steps such as different types of opt-in FVTs and alternatives to current retail rates that can be applied in the near-term.

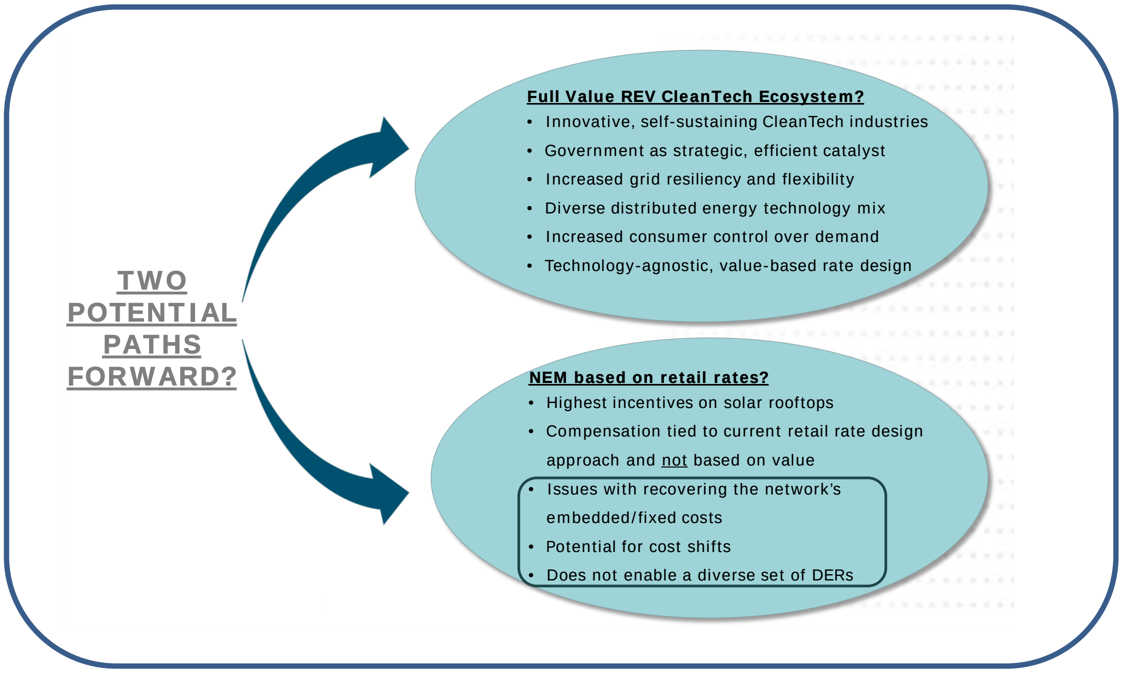
While the above discussion involves pricing and incentive mechanisms that could apply to all types of DERs, customer-sited solar PV warrants separate consideration because of New York's policy goals for adoption. This study therefore includes a set of reform options that could be applied in the near-term to distributed solar PV installations, with a focus on how the reforms would affect the solar adopting customer's bill savings vs. the 'value', i.e. the system avoided costs (with and without externalities), provided by distributed solar PV.

The final section of this study examines the longer-term transition pathways to full REV rate reform that represents what the Track 2 White Paper refers to as *"a technology-agnostic rate design that is more precise, both in recovering costs and in sending dynamic prices that prompt efficient DER participation by customers"*.

As stated earlier, the transition to that technology agnostic rate design will greatly depend on determining when the correct <u>enabling conditions</u> are present to trigger the next transition step, e.g. technology advancement, customer sophistication, achievement of policy goals, etc.

+ The spectrum of transition choices is organized around the general principles of being a **'gradual'** or 'incremental' change vs. a **'rapid'** or 'transformative' change.
+ There is no one best solution for mapping this spectrum to a particular transition path and end states (many options are possible that are equally valid and not mutually exclusive) and many compromises and choices will have to be made over time to implement REV along a pathway that balances the interests of various types of customers and stakeholders.
+ We believe that there is low risk in implementing the initial transition step of offering the FVT as an opt-in 'Smart Home' or 'Smart Business' rate. This is because if there is little or no interest then the status quo continues, and conversely if there is significant interest and participation the FVT design has built in 'circuit breakers' to manage load response and net injections.

Figure 9: There are two paths forward with REV. One is based on dynamic FVTs and rates with more efficient dynamic prices to retail customers that can enable a whole host of technologies. The second is a business-as-usual path that does not appropriately value resources or behavior that could potentially add the most value to the network.



1.3 Rate Design Fundamentals

1.3.1 COSTS OF ELECTRIC UTILITY SERVICE

There are two equally important types of costs that need to be reflected and collected through rates: **1) embedded costs** and, **2) marginal costs.** The embedded costs are fixed and were incurred to build and maintain the network. These costs have to be collected in a fair and reasonable manner from all customers, including active customers and prosumers, as all customers benefit and make use of the network.

The marginal costs are forward looking avoided costs. The latter should form the basis of any dynamic FVT or rate, but the former needs to be collected from all customers through their bills in a fair and equitable manner as all customers rely on the network unless totally disconnected.

Current compensation mechanisms like NEM may result in under collection of these costs from certain customers adopting DERs like solar PV (i.e. 'uneconomic bypass'), which could shift these costs onto customers that do not adopt DERs.

Figure 10: Fundamental Economic Rate[34]. The costs that need to be collected from and signaled to customers in electric retail rates and DER compensation mechanisms include both forward looking avoidable or marginal costs and embedded costs, both of which are equally important. This is reflected in the fundamental three-part economic rate formulation.

Marginal costs should signal the value of a change in consumption or production, while the total bill should collect the embedded costs.

	Cost Component	Description	Estimated Range
Part 1: ***Customer Charge*** *(Embedded Costs)*	Customer Charge	Costs of meter, billing, etc.	\$5-\$20/customer-mo
Part 2: ***Demand Charge*** *(Embedded Costs)*	Transmission / Sub-Transmission	Historical costs to be recovered	~\$1.0-\$5.0/kW
	Distribution	Historical costs to be recovered	~\$1.0-\$15.0/kW
	Other	Other historical, budget driven, or miscellaneous costs to be recovered	~0.5-4.0 ¢/kWh
Part 3: ***Marginal Costs*** *(Avoidable Costs)*	Energy	Forecast LBMP values and includes monetized carbon, SO2 and Nox costs plus generation marginal losses along with each utilities' merchant function charges	~5-7 ¢/kWh
	Losses	T&D losses incurred	~0.5-1.0 ¢/kWh
	Ancillaries	Forecast frequency regulation, reactive power, black start, and spinning/non-spinning reserves costs	~0.5-1.5 ¢/kWh
	Generation	Forecast ICAP values	~2-3 ¢/kWh
	Transmission	Congestion element in the LBMP and ICAP values	N/A
	Sub-Transmission	Deferral/avoided capacity cost value (Could be based on targeted 'hotspot' geographic value in locally constrained areas)	Locational, ~0.0-4.0 ¢/kWh
	Distribution	(Could be based on targeted 'hotspot' geographic value)	
	Customer Charge	Forecast customer cost changes, i.e. for billing costs	~0.0-0.5 ¢/kWh
	Public Purpose Charges	System Benefit Charges and Renewable Energy Portfolio Charges	~0.5 ¢/kWh
	Health, CO_2, Resiliency, etc.	Externalities to be potentially internalized	~0.0-5.0 ¢/kWh

[34] The estimated values and ranges of the cost components are based on E3 analysis, historical values, and high-level estimates in order to provide general information on these cost components that ranges across the New York utilities.

1.3.2 PRINCIPLES OF RATE DESIGN

There are many different competing interests (some of which are mutually exclusive) that have guided how electric retail rates have been designed over time. Determining an appropriate dynamic tariff that is based on 'value' is merely the latest consideration. We believe that our proposed FVT formulation reflects both traditional rate design principles as well as those articulated in the REV Track 2 White Paper.

1.3.2.1 Traditional Bonbright Rate Design Principles:[35]

Bonbright's principles have been the accepted standard in historical electric utility rate design and ratemaking for decades. These principles have generally been well-received by regulators and have represented a reasonable balance between the interests of the utility and its ratepayers, while taking into account the role that retail prices play in the market.

- **Effectiveness**
  - Recover the utility's allowed capital and operating costs and a fair return
- **Fairness**
  - Fairly apportion the cost of service among different customers (rates reflect cost causation)
  - Avoid undue discrimination
- **Efficiency**
  - Promote the efficient use of energy (and competing products and services)
  - Support economic efficiency – set prices to reflect marginal costs
- **Stability**
  - Ensure revenues (and cash flow) are stable from year to year
  - Minimize unexpected rate changes that may be adverse to existing customers
- **Simplicity, understandability, public acceptability, and feasibility of application**

[35] http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf

1.3.2.2 Updated REV Rate Design Principles from the Track 2 White Paper

The following represents the updated rate design principles that have been articulated in the Track 2 White Paper.

- **Cost causation:** Rates should reflect cost causation, including embedded costs as well as long-run marginal and future costs.
- **Encourage outcomes:** Rates should encourage desired market and policy outcomes, including energy efficiency and peak load reduction, improved grid resilience and flexibility, and reduced environmental impacts, in a technology neutral manner.
- **Policy transparency:** Incentives should be explicit and transparent, and should support state policy goals.
- **Decision-making:** Rates should encourage economically efficient and market-enabled decision-making, for both operations and new investments, in a technology neutral manner.
- **Fair value:** Customers should pay the utility fair value for services provided by grid connection, and the utility should pay customers fair value for services provided by the customer.
- **Customer-orientation:** The customer experience should be practical, understandable, and promote customer choice.
- **Stability:** Customer bills should be relatively stable even if underlying rates include sophisticated dynamic prices.
- **Access:** Customers with low and moderate incomes or who may be vulnerable to losing service for other reasons should have access to energy efficiency and other mechanisms that ensure they have electricity at an affordable cost.
- **Gradualism:** Changes to rate design formulas and rate design calibrations should not cause large abrupt increases in customer bills.

2 Unlocking the Distribution Value

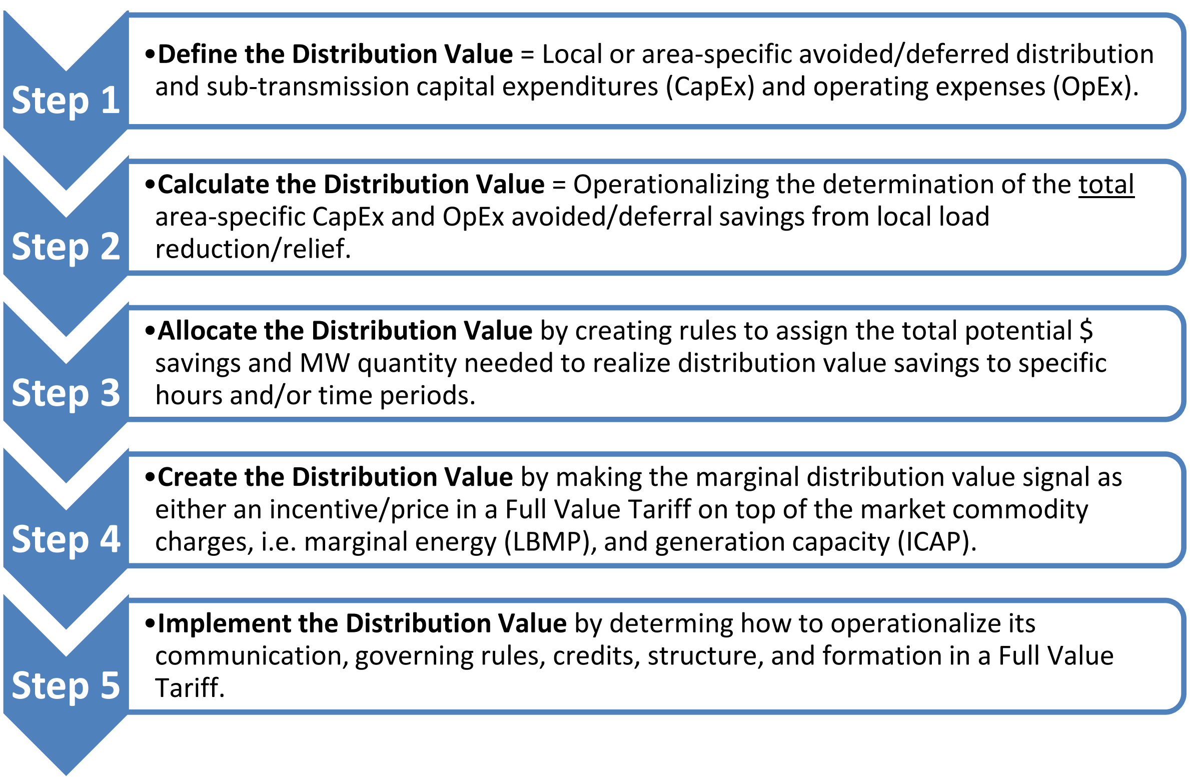
One of the main sources of 'value' in our proposed FVT is the locational 'distribution value' of DERs, which we define as the **avoidable** core cost components of sub-zonal transmission[36] and distribution capacity[37], both including the applicable energy losses[38]. While distribution loads and DERs can provide and should be compensated for additional services such as voltage and reactive power support (VaR), the overall value to the grid of these additional services is currently low given the additional cost and complexity to implement them. **We specifically propose to unlock the 'distribution value' of DERs in the near-term by linking the costs of future utility grid expansion to area and time-differentiated prices or incentives through our proposed FVT.**

As is done today by the New York utilities, each distribution utility would annually assess each distribution and sub-zonal transmission area for capacity shortfalls and identify least cost projects to increase capacity if an overload is forecasted. As illustrated in this section, the data from this study provide a forward looking marginal cost ($/kW-year) for each area linked to the utility's proposed capital budget for the next increment of capacity. **These capital budgets are the basis of what each utility may request and is authorized to recover from customers per approval by the New York Public Service Commission (PSC).**

[36] Sub-transmission capacity costs are the costs of the transmission and distribution system that directly supply distribution substations below the bulk transmission level which generally operates at voltages between 34.5 kV to 138 kV. Sub-transmission capacity costs and definitions can vary a great deal between utilities and even within different portions of a utility's service territory.
[37] Distribution capacity costs are the costs of the distribution system below the bulk transmission and sub-transmission level which generally operates at voltages below 34.5 kV. Distribution capacity costs and definitions can vary a great deal between utilities and even within different portions of a utility's service territory.
[38] These are the marginal transmission and distribution losses experienced at to delivery electricity from central station generators to end-use retail customers, which can be avoided in whole or part by localized DER or consumption changes.

To develop hourly prices for the basis of a dynamic FVT, the forward looking avoidable marginal cost ($/kW-year) is allocated to load levels above a threshold load in the area to set a price at each forecasted level of load. On a day-ahead basis, forecasted area loads are translated to prices using an allocation methodology and communicated to customers. By explicitly linking the costs of capacity by area, areas with relatively expensive upgrades will receive relatively high prices during peak load periods, increasing the economic opportunity for market-based alternatives. In the near-term, these prices can form the basis for area specific demand response programs, targeted credits for peak load reduction, or an opt-in FVT as a 'smart' rate. **Ultimately, the proposed approach exposes the utility capital expenditures to competition with DER technologies.**

Figure 11: Step by Step process to unlock the 'distribution value' of DERs to form the basis of a full value tariff.



2.1 Define the Distribution Value

The distribution planning or local capacity areas need to be defined clearly in order to determine the local marginal 'distribution value' of DERs based on the distribution utility's planned CapEx and forecasted OpEx needed to maintain and improve the distribution network. This type of information is expected to be part of the upcoming Distributed System Implementation Plans (DSIPs)[39]. Some of these CapEx and OpEx costs may be avoided or deferred with DERs while others will have to be spent regardless due to reliability or other factors.

Planning or Capital Expenditures (CapEx)

- Capital additions for reliability and resiliency, equipment replacement of aging infrastructure (poles, etc.), new customer connections.
- Large projects have multiple year lead times and are made for reliability.
- Utility engineers annually forecast and plan to serve the peak load with the largest one (N-1) or two (N-2)[40] capacity equipment out of service, although most portions of New York's distribution system is planned on a zero contingency basis (N-0).

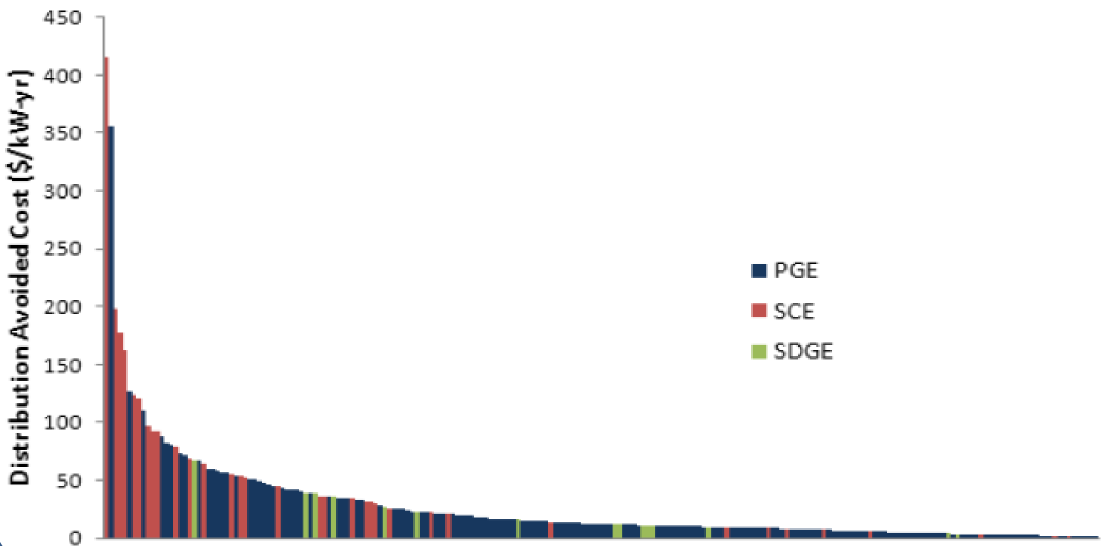
Operating Expenses (OpEx)

- Manual switching to balance loads, usually seasonal or one-time.
- Voltage regulation, < 1 min depending on loads, largely transformer tap changers, switched capacitors.
- Other operating costs such as maintenance, equipment repair, tree trimming, etc.
- Contingency and outage restoration, emergency basis, e.g. local isolated instances such as single transformer failure to system wide outages due to weather events.

[39] See the recent DPS guidance on the DSIPs: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF3793BB0-0F01-4144-BA94-01D5CFAC6B63%7d

[40] These refer to single element or double element contingency such as a loss of a single transformer or two transformers.

Figure 12: Distribution CapEx is a large budget item for utilities. A portion of CapEx costs can be avoided through reduction in load growth; the rest is aging infrastructure or new customer connects. The marginal avoided costs are variable (10 to 20x) by distribution planning area. See below an example from California that ranks the distribution avoided costs with the expectation a similar relationship would be observed in New York State based on E3's prior work[41].



2.2 Calculate the Distribution Value

Our proposal for the FVT is to focus on the CapEx portion of potential 'distribution value' in the near-term. This can be operationalized by the distribution utility categorizing each proposed CapEx item to determine which ones are driven by forecasted load growth and needed load relief. This distribution capital budget data can then be used to determine the marginal value of the load relief that would avoid or defer the capital cost. The capital budgets currently submitted by each utility already classify CapEx along these lines (to varying degrees of precision), which will presumably be expanded upon in the DSIPs.

[41] http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

Figure 13: Example of distribution level CapEx from ConEd that is load relief driven that can help determine the 'distribution value' of DERs.

Greenwood: Replaced Overloaded Equipment (2015)
Greenwood: Install Dueal Speed Fans On All 5 Banks
Inst.bkn 3n & Switch Feeder Connections At Greenwood Substation.
Replace Limiting TR7 At Corona #2
Uprate Limiting Bus Sections At East 75th Street
Install Additional Transformer Cooling TR2, TR4 At East 75th St
Uprate Syn Bus Sections At West 65th Street
Install Additional Transformer Cooling TR1, TR3 at E. 75th Street
Leonard St. - Uprate bus sections to achieve 300 hr rating of 4500 amps (2015)
Queensbridge: Replace Overdutied Disconnect Switches (2016)
East 179th Street - Install Water Spray on TR5 (2016)
East 179th Street - Install Fans for Limiting Bus, Breakers and Reactors assoc. w/ TR 4 (2016)
Fresh Kills - PR.2ES7300 - Repl 33kv Fdrs Assoc Tr#21w (2016)
Fresh Kills 33kV - Install additional cooling for Transformer 22E by replacing its radiators (2016)
Plymouth Street - Replace limiting equip. assoc. w/ TR5 (2017)
Replace Limiting Bus at Plymouth Street
Establish Newtown/Glendale TR4 /TR5 (2019)
Emergent Load
Parkchester Substation Install 4th Transformer
Parkchester 1 - Install Additional Cooling on Banks 3S & 4S
Hellgate S/S - Additional Cooling
East 179th Street: Switchgear And Bus Replacement (2020)

Example

Figure 14: Example of using DER or load reduction to defer approximately $10M in generic distribution CapEx with 5 MW of load reduction for 2-years.

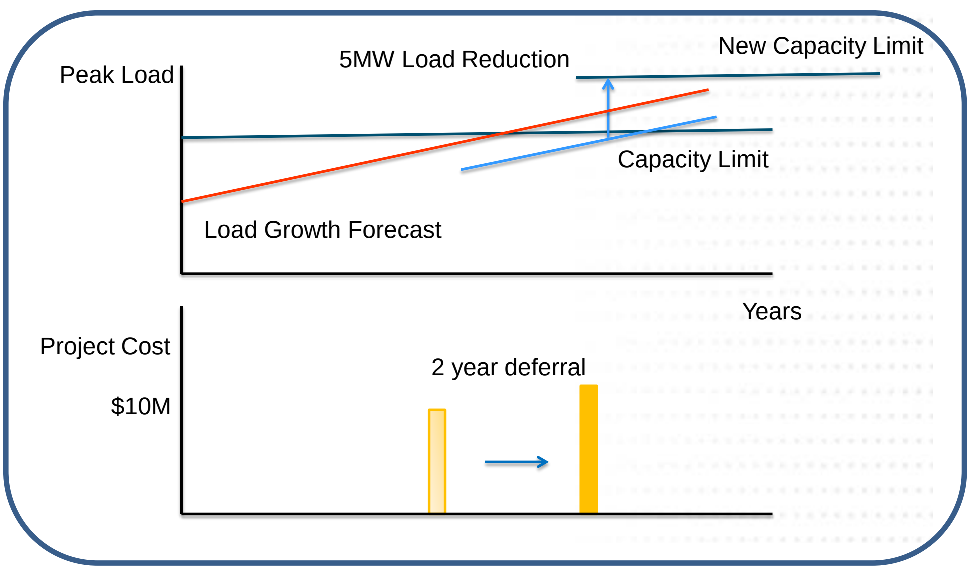


Figure 15: This deferral example results in $1M of CapEx savings or 'distribution value'.

+ Original PV of revenue requirement (PVRR)

- $10 million

+ Deferred PV of revenue requirement (PVRR)

- $9 million

+ Savings of approximately

- $1 million = $10 million * $\frac{(1+2\%)^2}{(1+7.5\%)^2}$
- $200/kW = $1 million / 5,000kW
- $10/kW-year for 20 years = $200/kW amortized over 20 years

Assumptions: Inflation = 2%, WACC = 7.5%

2.3 Allocate the Distribution Value

Once the total 'distribution value' has been calculated for a particular area then the next step is to create a rule or methodology to allocate this total 'distribution value' to specific time periods or hours in order to allow DERs and loads to provide the value through a change in electricity consumption and/or production. This can range along a spectrum from allocations based on demand coincident with the peak loads driving the need for the distribution CapEx, e.g. a number of hours (for example the top 100) approximating the probability of peak load[42], the number of hours over the 'N-1' or 'N-2' rated capacity limit of a substation or transformer, the single annual peak hour, or to pre-defined time periods. We present one allocation methodology for both distribution and sub-transmission avoidable capacity costs based on evaluating loads above a predefined threshold that are deemed to be triggering the need for distribution CapEx. The deferral or avoidance 'distribution value' of DERs is then allocated to those hours based on each of those hours' proportional impact.

[42] For example, peak capacity allocation factors or PCAFs can be calculated by taking the top 100 load hours in a year and calculating the total energy (MWh) in those hours. The PCAFs are then determined by dividing the load in each of those 100 hours by the total or sum of the loads of those hours, i.e. if total load of the top 100 hours equals 500 MWh and one hour in that top 100 has a load of 50 MWh; the PCAF for this hour would be 10% (50/500); a similar calculation would be performed for each of those 100 hours so the total hourly percentage will equal 100%. This methodology allows an annual capacity price to be allocated to certain peak hours based on the approximate probability that it will be the peak.

Figure 16: An allocation rule translates the total 'distribution value' of DERs to specific hourly/time-variant prices by calculating the change in the utility's present value of the revenue requirement.

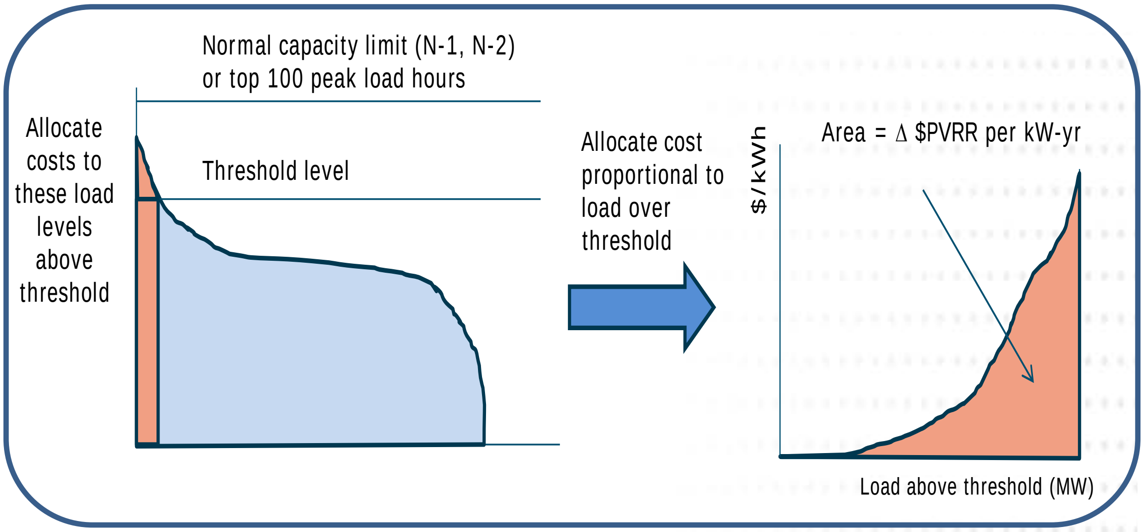


Figure 17: Example of specific distribution cost allocation for a Downstate utility based on 2012 specific substation load data and that substation's N-2 rating with an annual distribution capacity value assumed to be $100/kW-year.

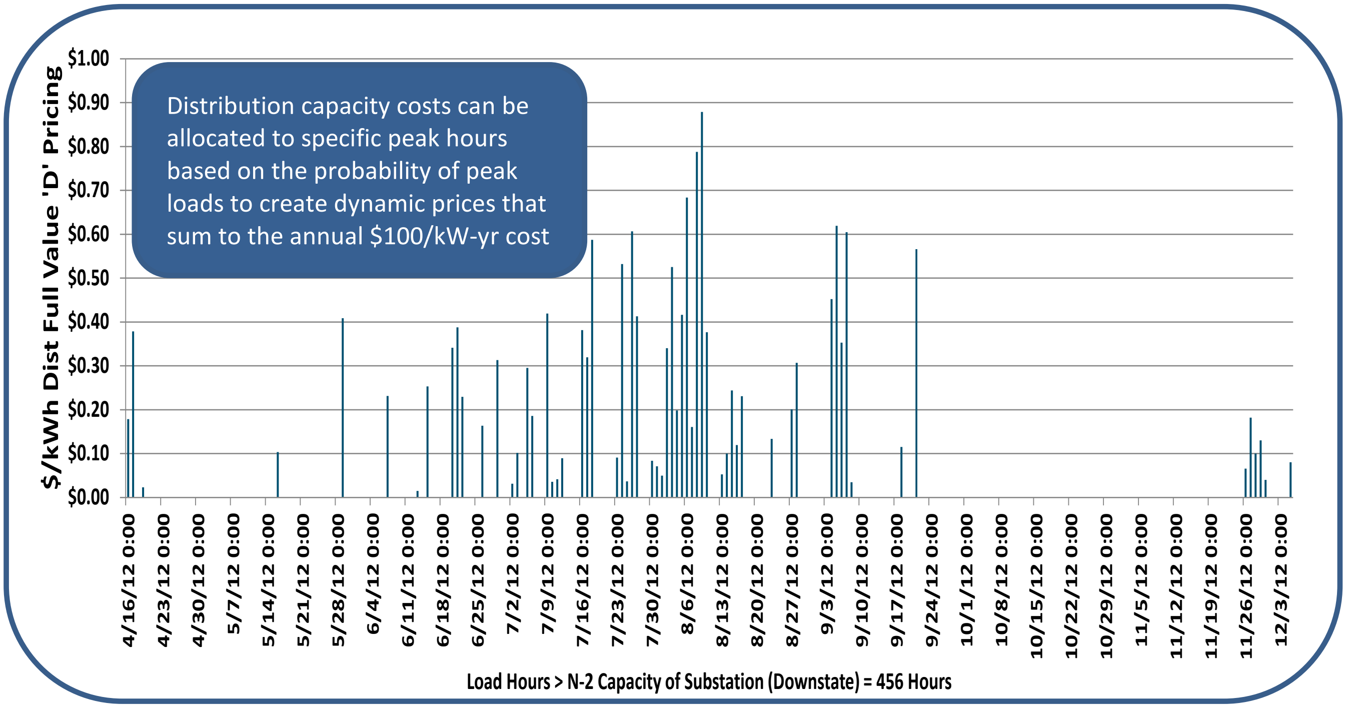
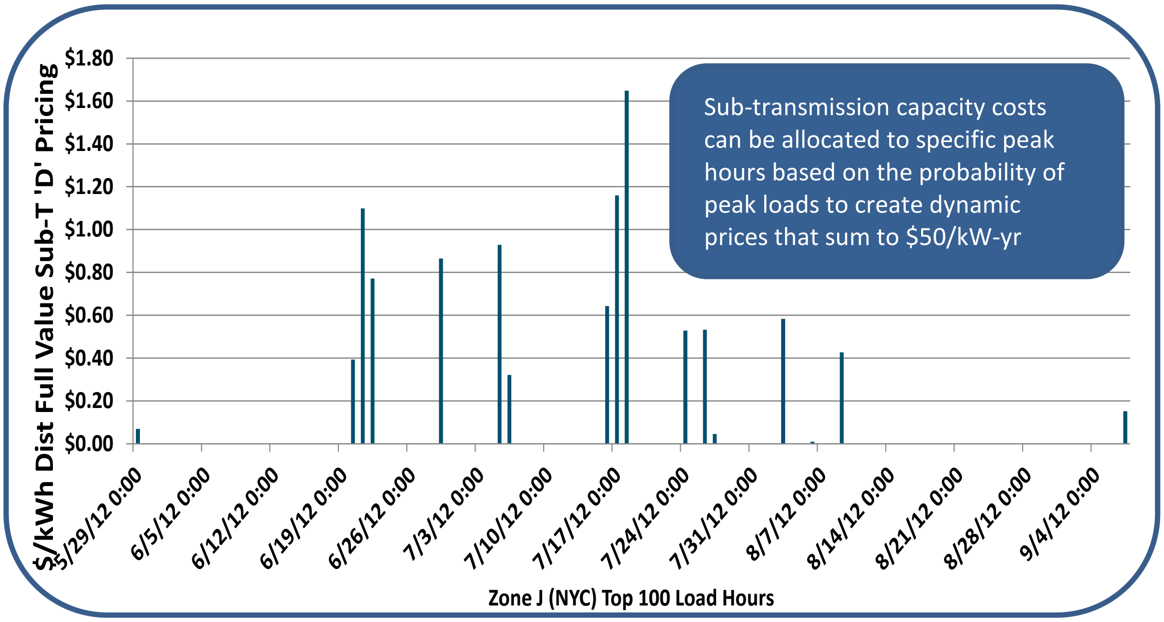


Figure 18: Example of specific sub-transmission cost allocation for a Downstate utility based on the top 100 peak zonal load data for New York Independent System Operator (NYISO) Zone J with an annual sub-transmission capacity value assumed to be $50/kW-year.



2.4 Create the Distribution Value Dynamic Prices

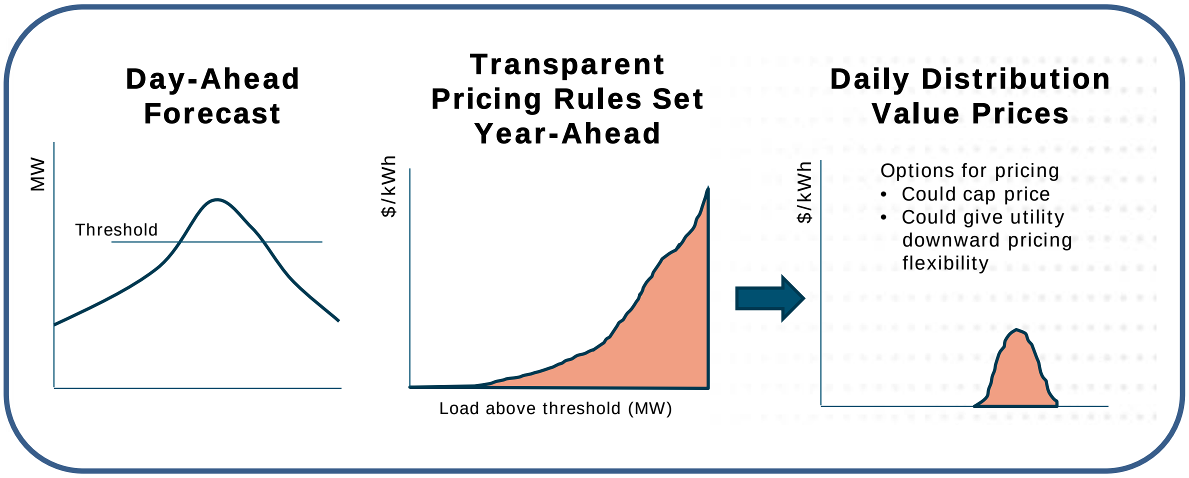
Once the ‘distribution value’ has been defined, calculated, and allocated, the next step is to construct a FVT that allows this value to be realized by DERs and responsive loads. Including the ‘distribution value’ dynamic price opens up the distribution function of a utility to competition as the marginal CapEx costs can now be potentially deferred and/or avoided via non-wires solutions. If no solutions materialize from the market the distribution utility would proceed with the capital project. The distribution dynamic price will be higher in locations that have upgrades or additions that are more expensive compared to areas with lower or zero cost of upgrades and additions. These upgrades and additions can also include the value of any upgrades and additions needed to enable higher penetration of DERs. These higher values or dynamic prices can be used to enable a host of alternative technologies or market-enabled measures.

The mechanism to set the distribution dynamic price would be to forecast load levels each day assuming no additional distribution price signal is included and then add a dynamic price for each hour over the established threshold as described in the previous section. This is a predetermined process with the threshold and the prices at different forecasted load levels established in advance in an annual cycle.

In return for receiving a distribution dynamic price, customers in the local area will receive a bill credit. The credit is designed such that the average customer would have an equivalent annual bill if they do not shift away from the higher dynamically priced hours. As customers shift away from these hours they consume less during the high priced dynamic priced hours and their overall bill decreases. The same applies for any net injections of energy to the grid, which would receive higher compensation in the higher dynamically priced hours.

A number of different operations or rules can be constructed in a FVT on top of this basic structure to make the tariff fairer and no higher than necessary to achieve load response. For example, the PSC can allow the utility downward pricing flexibility if the necessary load and/or DER response can be elicited from the market at lower costs. In addition, if loads are outside certain expected boundaries given a certain price, there could be 'circuit breakers' or price caps that further adjust the prices. In addition, an annual true-up mechanism on actual revenue collection is needed to maintain alignment. For example, more hot days than predicted will result in utility over-collection of the revenue requirement. Excess revenue should be credited back to customers and can be used as a way to incent program participation by providing an upfront credit.

Figure 3: Example of sending the 'distribution value' of DERs signal on a day-ahead basis.



2.5 Implementation of the Distribution Value in a Dynamic Price

2.5.1 ESTABLISHING THE CREDIT

Setting the appropriate bill credit along with the dynamic distribution prices will take experience, and this process should evolve and be refined over time. The credit should be designed so that the average customer in that local area is expected to be 'bill neutral' assuming they do not adjust their consumption or have any on-site production. Of course, we do expect customers and technology to respond to these higher prices, so *realized* dynamic distribution pricing revenue should be less than the bill credits.

We recommend that the bill credit be equal to the expected revenue that would be collected from the dynamic distribution pricing on the overall class profile for a typical weather year in excess of the revenues needed for the utility's embedded cost recovery. On one hand, some customers will naturally pay less if their load shapes are 'better' than class average by naturally not being coincident with the higher priced hours, but this 'discount' is based on the lower costs to serve these customers. On the other hand, some customers will pay more if their load shapes are 'worse' or more coincident with the higher price hours than the class average. All customers subject to dynamic distribution pricing will have an opportunity to reduce their bill by shifting away from the higher dynamically priced hours.

As described, net injections of electricity back to the grid, e.g. solar PV, would receive the same payment as consumption changes. The cost to the utility of purchasing customer-sited power at the distribution peak periods in a constrained area will be paid by those customers in the local area consuming at the same time. All of the credits and payments are isolated to the specific area.

2.5.2 VALUE TO ALL RATEPAYERS

The following example shows an illustrative example from the perspective of a program administrator in a particular year using dynamic distribution pricing to reduce distribution loads rather than spending utility capital on distribution capacity expansion. First, there is a credit sent to customers for their participation in dynamic distribution pricing. This is a cost to the utility of foregone revenue. Offsetting this cost is an additional revenue stream from sending the dynamic distribution prices during constrained times (e.g. 'surge' or FVT revenue). If customers shift load away from these times, the revenue will not equal the credits. In addition, there are payments for net injections of electricity onto the system during the constrained period that could also offset this revenue. Finally, there is the benefit for not having had to spend the capital budget on the capacity upgrade due to load response and customer-sited generation. The figure below illustrates the benefits to the customer-sited net injections onto the system and the benefits to dynamic pricing participants along with the additional benefits that can benefit all ratepayers.

Figure 19: Illustrative ratepayer and FVT participant costs and benefits associated with building distribution capacity vs. avoiding that capital expense using FVT-induced load response.

Option 1:
Build Distribution Capacity

Example Description:
Load growth in a distribution constrained zone has led to a need to build a $10M upgrade to an existing substation to increase capacity

Cost Breakdown

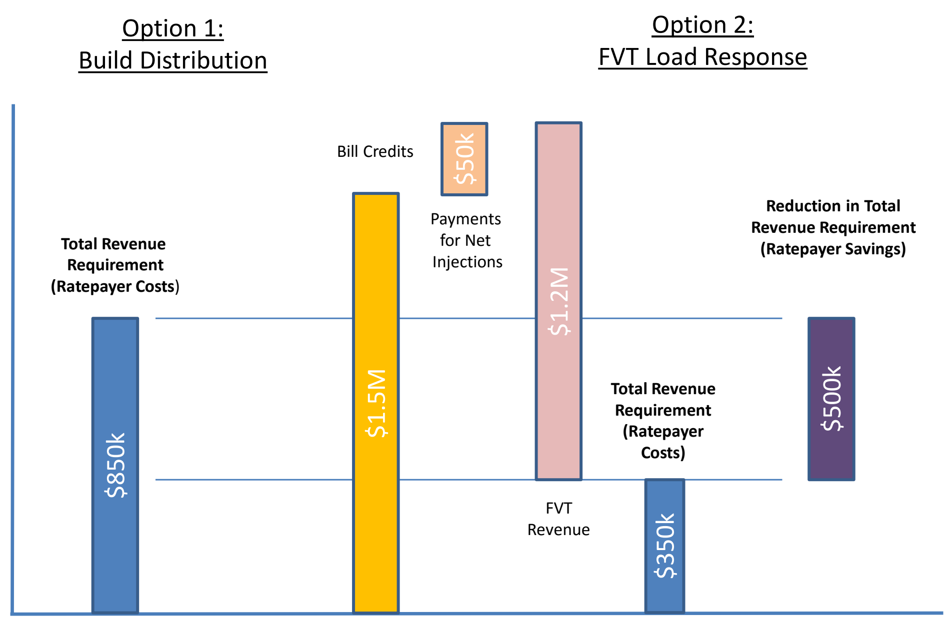
- $10M present value of revenue requirement = **$850k/year** ratepayer expense for 30-years to build additional capacity (assume an 8.5% carrying charge)
- This is collected from all ratepayers to fund the capacity expansion needed at the substation

Option 2:
Full Value Tariff Load Dispatch

Example Description:
Annual avoidable capacity benefit equals $850k/year realized by a permanent reduction in substation peak loads through load response via the Full Value Tariff

Cost Breakdown:

- 3,000 customers opt-in to FVT, 500 of which are prosumers, i.e. rooftop solar PV
- Each customer receives an annual $500 upfront bill credit against network subscription charges
- FVT customers change their loads in response to dynamic pricing and pay $400 (if FVT customers had made no changes in loads then they would have paid $800)
- Prosumers are paid at the FVT for net injections onto the grid ($100 each)
- This results in the FVT program costing ratepayers a total of $350k/year ($1.5M in bill credit costs and $50k payments to prosumers vs. $1.2M in FVT revenues) to realize $850k in avoidable capacity benefits, $300k in bill savings for FVT customers ($100 each), and **total net benefits to all ratepayers = $500k/year**



2.5.3 COMPARISON TO TRADITIONAL DEMAND RESPONSE

The biggest advantage of the proposed dynamic distribution prices is that there is no need to calculate a baseline and measure changes in consumption relative to 'what would otherwise have occurred.' For demand response (DR) programs that operate a few times a year, a baseline can be established with heuristic rules. But for technologies that operate potentially every day, establishing a reliable baseline is problematic.

Another added feature is that there is no need for formal capacity commitments with dynamic pricing since the full value tariff is a market based price mechanism for animating a technology agnostic response. This should make the FVT more acceptable and popular for customers and lead to a higher rate of customer participation than current demand response programs have achieved. More, smaller, load changes can add up to meaningful adjustments to load overall. With utility experience, the load response at different prices will become predictable. The ultimate goal is to have this load response become at least as predictable as current demand response programs are today. Experience with the FVT and distribution level dynamic pricing will be necessary to make the distribution utility comfortable with using the dynamic distribution price mechanism for reliability. This 'trial' or 'market test' would be repeated daily and will result in the utility or DSP learning a great deal about monitoring, managing, and dispatching local distribution loads.

Another observation is that the FVT with distribution level dynamic pricing can be combined with traditional demand response and aggregator bidding to provide load reduction in an area. A single customer cannot participate in more than one (or they would be paid twice for the same action), but several programs can operate in parallel.

The following is a table of the pros and cons of our FVT with distribution level dynamic pricing proposal as compared to existing demand response programs.

Table 1: Pros and Cons of FVT compared to traditional demand response for local load relief.

Pros	Cons
+ There is no need to estimate a baseline to determine how much load reduction was achieved since all load and net injections are priced identically. + There is no need for formal capacity commitments or any other agreements as the FVT is a market based price mechanism for animating technology agnostic response. + Sending dynamic prices leads to a greater share of customers participating along with utility and DSP learning about monitoring, managing, and dispatching local distribution loads. + The FVT can be offered in parallel with other more traditional demand response programs.	+ There could be a perception that the utility is raising prices in the precise times and places when electricity is most important. This needs to be managed with the credit and as an opportunity for participating customers. There also need to be clear, formulaic rules around price setting, including 'circuit breakers' when loads deviate far from predictions (high or low). + Without a 'circuit breaker,' situations could arise in which excess load response or net injections cause issues with the local distribution power flow. This can be alleviated by having rules about the amount of distribution load forecasted day-ahead vs. realized in real-time that is paid the full value.

3 Developing the Full Value Tariff

In order to develop the full value tariff we begin by defining the key design constraints and goals based on the REV Track 2 Whitepaper and assessment of the REV goals. These include the scope of the FVT, the granularity of the price signal, the policy drivers and focus of REV, and the enabling conditions needed for a successful transition to the FVT.

Using the ‘three part’ retail rate structure described in the Track 2 Whitepaper, we first establish the conceptual design of the full value tariff. The conceptual design draws from network subscription pricing in other network industries including cellphone and cable networks, established cost-of-service ratemaking principles in electric utility service, and an assessment of Bonbright rate design principles of fairness, ease of implementation and other factors.

With the conceptual design established, we develop illustrative residential FVT rates for a downstate (Consolidated Edison) and upstate (National Grid) utility using their most recently filed embedded and marginal cost of service studies along with historical market data for a retrospective ‘test year’ of 2012. A 2012 ‘test year’ was used to align the utility cost of service studies and to examine the impacts of alternative rate designs in isolation with complete hindsight. The illustrative FVT rates are modeled after a ‘fundamental’ economic cost causation rate that is adjusted to collect the same overall revenue from the residential class as was collected in 2012. The formulation of the ‘fundamental’ economic rate is presented in the appendix of this study[43].

Lastly we use a simplified residential building energy simulation model to evaluate the potential bill savings for a range of ‘smart home’ technologies, including solar roof, energy efficiency,

[43] In order to develop a practically implementable FVT, we begin by using utility filed embedded cost of service (ECOS) studies and historic market data to calculate the revenues that would be fairly collected for each utility function for a range of customers. This is the amount that would be collected in a fundamental cost causation rate, i.e. functional utility costs assigned to the customer causation classifications. We perform this analysis for an upstate utility (National Grid) and a downstate utility (Consolidated Edison) and for residential customers of different sizes or strata to develop a range of perspectives.

smart A/C, smart heat pump, and smart electric vehicle charging. We evaluate four cases for each utility: with and without explicit inclusion of non-financial costs of energy use such as harmful air emissions in the FVT, and inside and outside of transmission and distribution (T&D) constrained zones. While the annual bill of most customers would not change significantly under the FVT if customers do not respond to the dynamic price signal, there is a value-based business case for the smart management of customer load for customers on the rate.

3.1 Design Elements of the Full Value Tariff

There are a number of key decisions to make in developing the FVT that guide its overall design. These include the scope of which customers are eligible over what time period, what the desired policy outcomes are, and whether to specify a design that requires supporting infrastructure such as advanced metering infrastructure (AMI or 'smart' meters). The design choices in the FVT will directly affect key issues such as acceptance by customers and ease of the transition path.

We identify five key decisions that guide the design of the full value tariff:

1. **Scope:** Ultimately, the FVT should be available to all customers. We segment the market into two groups. The first group contains mass market customers including residential and small commercial, which currently do not have advanced metering infrastructure and are not demand-metered. The second group contains large customers, which are demand metered and in most cases have existing interval metering.

2. **Time-differentiation:** We propose a high level of granularity in the dynamic price (hourly) and area-differentiation (sub-transmission and distribution area zones). In order to effectively implement a dynamic rate with any granularity we need an electronic control system receiving the dynamic prices and operating controls. Once that leap is made, the additional granularity of moving from broader time-of-use (TOU) periods to hourly pricing does not introduce significantly more complication from an

enabling point of view. Moving from TOU to hourly pricing, however, is critical for some DER technologies such as smart thermostats and energy storage devices to maximize their value to the grid.

3. **Area-differentiation.** Area differentiation is critical to induce investments that can support load management or generation in the high value areas at the appropriate times in order to maximize the value of DERs to the grid. The potential issue is not so much one of complexity, but of equity. We do not want to introduce structural and significant bill increases for customers in locally constrained areas which would be a significant departure from traditional system-average retail prices. Therefore, in order to implement area-differentiation, we propose providing all FVT customers in the constrained areas a <u>**bill**</u> <u>**credit**</u> and in return introduce the dynamic sub-transmission and distribution hourly prices during peak constrained times.

   The credit would be set such that the typical customer annual bill is unchanged if their consumption is unchanged based on forecast area- and time-differentiated prices. On one hand, with this model some customers can benefit naturally (i.e. structural 'benefiters') if their natural consumption cycle is not aligned with the local peaks and high price hours or time periods. However, these customers are lower cost to serve so their bill savings are justified based on the underlying costs. On the other hand, some customers would see bill increases if their natural consumption cycle is more aligned with local peaks and higher price hours or time periods, but they would have the opportunity to shift consumption away from these high cost hours through behavioral changes, technology adoption, or market offerings.

4. **Policy Outcomes.** The retail rates send price signals to customers and should provide appropriate incentives for behaviors, investments in energy efficiency, and a range of smart control technologies that align with the policy goals articulated in the REV Proceeding. The rate itself should be technology neutral and available to all forms of load management. For self-generation, payments should be equal to value. However, we recognize that the full value may include potentially non-financial benefits of energy

conservation, efficiency, and self-generation such as reduced air pollution and greenhouse gas emissions. With the ideal formulation of the FVT, offering a net metering rate would become a non-issue because bill savings are by definition equal to the grid benefits, and there are no inappropriate net costs.

5. **Transition Path.** The FVT must have a transition path to the full scope proposed. Initially, the FVT would be an opt-in rate for those customers that wish to deploy smart load responsive technology (a 'smart home' or 'smart business' rate). As an opt-in rate, the FVT should be revenue neutral for the class average customer. This means that there should be no structural bill increase or decrease for all customers. Ultimately, the FVT would transition to a default rate in the long run when the appropriate enabling conditions are in place. Transition to a default rate depends on a number of factors, but such a transition will be difficult if there are significant bill impacts on any particular customer segment (e.g. small usage customers).

3.2 Conceptual Rate Design

To meet the goals of REV, we have structured the FVT so that there is an hourly marginal price equal to the hourly marginal cost. If this can be achieved, then the price will signal economically efficient behavior and any energy efficiency, smart technology, or customer-sited generation will receive its 'fair' compensation based on the actual value to the system. The FVT would then become one of the business models to enable the necessary technology investment for load management in homes and businesses.

We structure the FVT similarly to the 'three part' rate structure described in the Track 2 White Paper, which is also aligned with the structure of the fundamental economic or cost-causation rate detailed in the study appendix. This three part rate consists of a customer charge, a demand charge, and an energy charge. The FVT is similarly structured with a ***customer charge***, a size-based ***network subscription charge***, and a varying hourly ***dynamic price***.

Table 2: The 'Three Part Rate' vs. Full Value Tariff Formulation.

	'Three Part' Rate based on Fundamental Cost-Causation Rate	Equivalent Full Value Tariff Component
1	**Customer Charge** ($/customer) collects embedded costs and expenses associated with serving the customer such as the meter, meter servicing and customer billing.	**Customer Charge** ($/customer) similarly based on the costs associated with serving the customer.
2	**Demand Charge** ($/kW of coincident and non-coincident peak loads) collects embedded costs and invariant costs of the grid based on a customer's use of the existing grid. Costs include distribution, sub-transmission, transmission, any remaining utility-owned generation assets of the grid, and regulatory balancing accounts, adders, and true-ups.	**Network Subscription Charge** ($/max average kW-month for residential and small commercial, $/kW of subscribed demand for large commercial) collects the embedded costs and invariant costs of the grid based on the customer's use of the existing grid. Costs include distribution, sub-transmission, transmission, any remaining utility-owned generation assets of the grid, and regulatory balancing accounts, adders, and true-ups.
3	**Marginal Costs** ($/kWh) collect forward looking marginal or avoidable costs of serving customer load including avoidable zonal hourly energy costs and losses along with avoidable delivery capacity and generation capacity costs during peak periods, and any avoidable merchant function charges allocated to peak hours.	**Dynamic Price** ($/kWh) collects forward looking marginal or avoidable costs of serving customer load including avoidable zonal hourly energy costs and losses along with avoidable delivery capacity and generation capacity costs during peak periods, and any avoidable merchant function, renewable energy, and efficiency programs. Also can include externalities linked to air emissions of CO_2, and criteria emissions (PM, SOx, NOx).

3.2.1 CUSTOMER CHARGE COMPONENT

This customer charge constitutes the costs and expenses associated with serving the customer such as the meter, meter servicing and customer billing. We base this component of the FVT on the embedded cost calculations from the utility embedded cost of service studies. A detailed formulation and calculation of these costs can be found in the appendix.

3.2.2 NETWORK SUBSCRIPTION CHARGE COMPONENT

Many owners of networks with high fixed costs charge an ‘access’ fee of various sorts to allocate the costs of the system across all of the users that benefit from having access to the network. The ‘access’ fee can take different forms, for example, a ‘line access’ fee for cellular networks or bundled cable television packages.

The first key principle is that the network subscription charge for electricity customers should be size differentiated, e.g. linked to the subscribed level of data in a cellular phone plan. We propose a size-differentiated network subscription charge for the FVT for several reasons. **First**, a size-based network subscription charge fairly allocates the fixed costs of the network to each customer’s use of the grid (customers who are larger use more of the existing network than smaller customers). **Second**, implementing a size-based charge can avoid undue bill impacts on smaller customers. The figure below compares network subscription model for cell phone carriers and electricity service. **Third**, introducing a network subscription charge creates a more economically efficient pricing structure by moving fixed costs that are currently recovered volumetrically to charges that are more fixed in nature. Without having to collect sunk costs on a volumetric basis, the remaining volumetric charges are closer to the full marginal cost and can lead to more economically efficient outcomes.

Figure 20: Comparison of network subscription pricing by cell phone carriers vs. a potential analogue in electricity.

Cell Phone Carriers Charge for Increasing Network Usage

Data Plan	1 GB	2 GB	4 GB	6 GB	8 GB
Fixed Fee	$40/Line				
Data Charge + Cell Phone	$50/mo	$60/mo	$70/mo	$80/mo	$90/mo
Data Charge + Cell Phone + Tablet	$60/mo	$80/mo	$90/mo	$100/mo	$120/mo

How Can Network Owners/Operators Charge for Access?

Size differentiated customer access charge aligns with fair allocation of the costs of the system

Sized Based Residential Charge (Monthly Consumption in Peak Month)	300 kWh?	400 kWh?	500 kWh?	700 kWh?	1000 kWh?
Customer Charge	$Customer Charge/month + ¢/kWh rate				
Network Subscription Service	$20/mo + Dynamic Price	$30/mo + Dynamic Price	$40/mo + Dynamic Price	$50/mo + Dynamic Price	$120/mo +Dynamic Price

ILLUSTRATIVE

There are many choices for exactly how to define 'size' in the size-based network subscription charge. After reviewing a broad range of options, we recommend one approach for an implementable FVT rate for currently non-demand metered residential and small commercial customers and another approach for currently demand-metered larger commercial customers.

A fundamental economic rate designed for perfect fairness in collection of embedded costs without regard to ease of implementation would look much like the wholesale transmission capacity reservation system. Customers would commit to long-term purchases of capacity they need for each part of the network system necessary to serve their load. The network owner (utility) would then have contracts for its available capacity and if demand for capacity exceeded available capacity, the network owner could host an 'open season' to subscribe customers for new capacity contracts and add capacity to the system.

For currently demand metered customers, we propose a transition to a capacity reservation, i.e. 'contract demand' system to determine the size-based network subscription charge. For example, a demand metered customer might subscribe to 500 kW if they could meet their needs and not exceed 500 kW. This system is more efficient than a metered monthly demand charge because it reflects the fact that network costs are long term investments and if a customer has lower maximum demand in one month this does not reduce the costs of the system. A similar outcome could be achieved using a rolling current and 11-month maximum demand, though capacity reservation better reflects the forward looking needs of a customer and is closer to the fundamental economic rate.

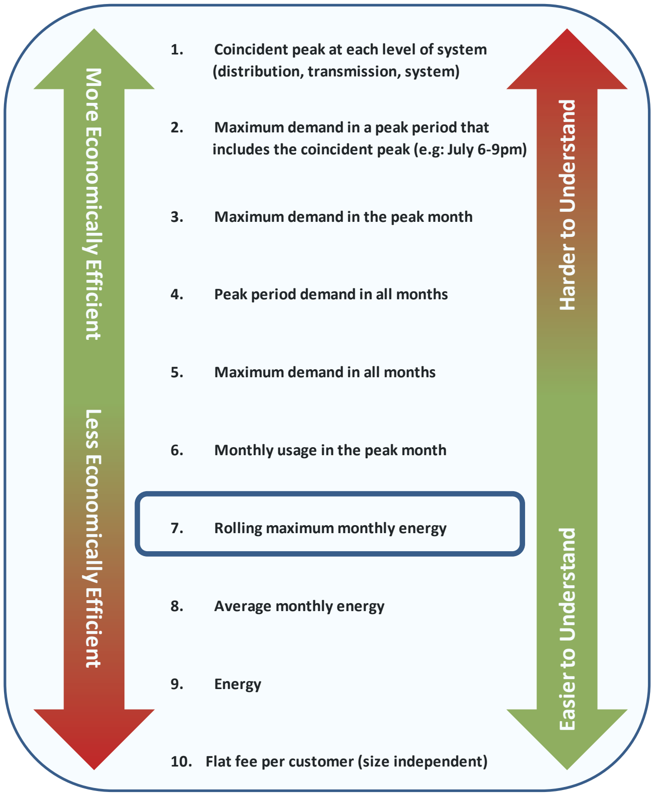
For currently non-demand metered residential and small-commercial customers, the gap between the current system of paying embedded costs in a volumetric charge ($/kWh) and a capacity reservation system is too wide for implementation. A second best approach of moving to demand charges that allocate costs based on non-coincident peak (NCP)[44] and coincident peak (CP)[45] demands would be the most precise cost-based way to price services, but this too we see as too complex for residential and small commercial customers. Instead, we recommend that the network subscription charge for residential and small commercial customers be based on a customer's <u>maximum monthly energy usage</u>[46] over the current and 11 prior months, i.e. 12-month maximum monthly energy usage. The monthly usage in the peak month, e.g. 600 kWh, 800 kWh, 1,000 kWh, etc. would be the billing determinant for the network subscription charge.

We chose the rolling maximum monthly energy usage for the residential and small commercial customers because the quantity is 1) easy for customers to understand and predict, 2) conveys the concept of peak usage of the grid, and 3) conveys some economic benefits to customers from usage reduction actions such as energy efficiency and solar PV investments.

In deciding upon the rolling maximum monthly energy usage billing determinant, we evaluated a full range of billing options. The options are listed below in generally declining order of cost-basis precision, and increasing order of simplicity and customer understandability.

[44] NCP= non-coincident peak, which equals the customer's peak load which can occur in non-system peak hours.
[45] CP= coincident peak, which equals the customer's peak load that occur at the same time or is coincident with the system peak.
[46] This usage level is based on <u>net</u> on-site consumption, which means that customers that self-generate do not pay grid access charges for energy generated and consumed behind the meter. Only kWh consumed on-site from the grid is used in determining the maximum monthly usage figure and exports to the grid do not reduce the total.

Figure 21: Range of options to determine the appropriate network subscription charge to demonstrate the choice between economic efficiency and customer understandability and simplicity in design.



Again, we did not propose any of the demand charge options because they are likely too complex for the currently non-demand metered mass market residential and small commercial customers. This is mostly due to these customers' unfamiliarity with the concept of variability in instantaneous usage. The average monthly energy and the simple energy charges were rejected as being too unrelated to grid peak usage and the flat fee was inappropriate for all but the customer-related and revenue cycle service related costs. The customer's use coincident with the system and the sub-transmission and distribution level peaks are separately addressed via the dynamic pricing mechanism.

In presenting the network subscription charge in the FVT and on the customer bills, we recommend that the charge be expressed as a $/kW-month charge, rather than a $/kWh charge. This presentation will prevent confusion with the energy consumption in the actual billing month, and would allow for an easier transition (if desired in the future) to actual demand charges for the residential and small commercial customers. The actual network subscription portion of a customer's bill would remain unaffected by the choice of $/kWh or $/kW-month network subscription rates.

The bill would show network subscription (kW) * network subscription rate ($/kW-month), with a note about which month their peak consumption occurred along with their energy usage during that month. The calculation of the network subscription (kW) amount would use a simple fixed factor to convert maximum monthly energy to kW.

The network subscription kW would be calculated as:

$$Network\ Access\ kW = \frac{Max\ Monthly\ Energy}{Days\ in\ the\ billing\ period\ of\ \max month} * X$$

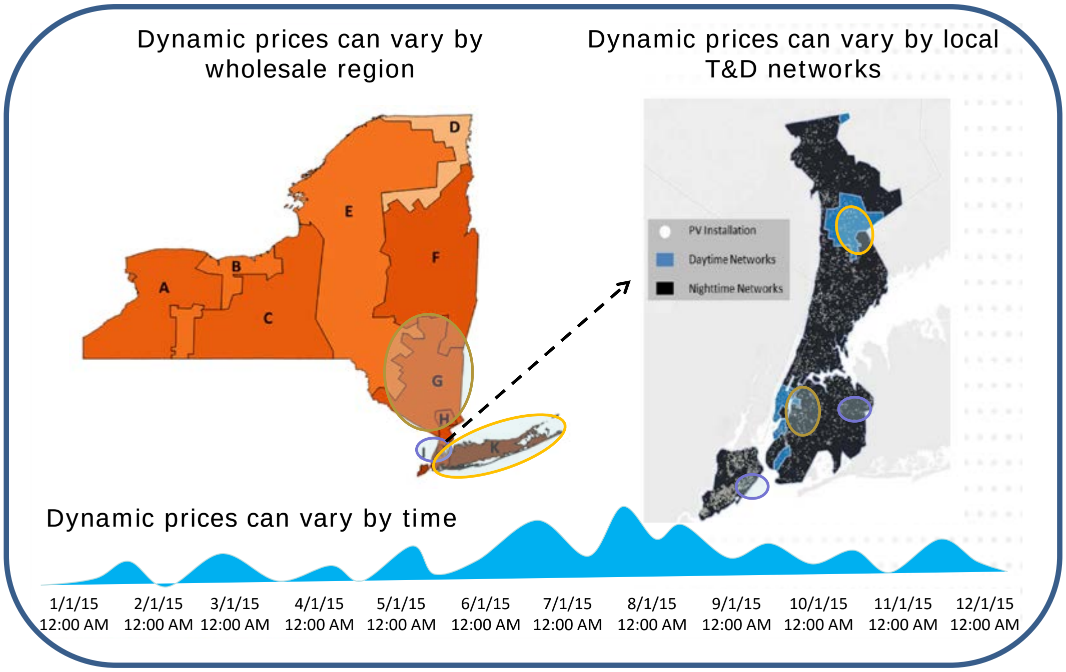
Where **X** is a conversion factor that is set for each customer class as part of the FVT rate design process. For our examples, the conversion factor is based on the average residential class twelve monthly non-coincident peaks (12NCP) and class coincident peak (CP). This results in a $/kW-month charge that is the same as what the utility would use if the utility were actually billing customers for their average NCP and CP demand for the average customer.

$$X = \frac{(Class\ 12NCP + 12 * Class\ CP)/2}{Sum\ of\ \left(\frac{Customer\ Maximum\ Monthly\ Energy}{Days\ in\ billing\ period\ or\ \max month}\right)}$$

3.2.3 DYNAMIC PRICING

'Dynamic pricing', i.e. pricing that varies by area and time depending on the current system conditions, is the third part of the three-part rate. The proposed concept is similar to real-time pricing of zonal or nodal energy plus system and locational capacity value including the appropriate energy losses. The proposed dynamic prices would vary by time and location depending on system conditions and the overall supply and demand balance.

Figure 22: Under the FVT prices are dynamic at both the wholesale and local area levels as well as being dynamic over time[47].



<u>Our proposed dynamic pricing formula for the FVT is as follows:</u>

Dynamic Price =
Zonal LBMP (h) + ICAP (h) * system losses (h) +
Merchant Function Charge ($/kWh) +
Sub-Zonal Transmission Capacity (h) * sub-zonal losses (h) +
Distribution Capacity (h) * distribution losses (h) +
RPS and EE program costs ($/kWh) +
net externalities ($/kWh) {if included}

+ *Zonal LBMP (h)* is the day-ahead zonal NYISO market price.
+ *ICAP (h)* is the annual ICAP price allocated to top 100 system (New York Control Area) load hours.
+ *System losses (h)* is the loss by hour between the customer at the distribution level and the bulk power system.
+ *Merchant Function Charges ($/kWh)* are the utility costs of transactions, hedging, etc.

[47] The graphic of ConEd's daytime vs. nighttime peaking networks and solar PV installations can be found here: http://www.capitalnewyork.com/sites/default/files/CONEDDEMO3.pdf

- *Sub-zonal transmission capacity (h)* is the allocated sub-zonal marginal costs as illustrated in the earlier value of distribution chapter.
- *Distribution capacity (h)* is the similarly allocated distribution marginal costs.
- *RPS and EE program costs ($/kWh)* are the costs collected from customers to meet the State's renewable and energy efficiency goals.
- *Net externalities ($/kWh)* are the deemed non-financial costs of air pollution including CO_2 and criteria emissions over and above the RPS and EE program costs used for programs to mitigate these externalities.

Day-ahead prices. While more complex forms are possible, we propose that the prices are formulated and sent to customers a day ahead of the actual operations. Having dynamic prices a day ahead would allow a customer's systems to set appropriate consumption schedules (e.g. pre-cooling the building or charging storage devices). If controls and technologies evolve, it would also be possible to have customers participate in real-time markets. Real-time participation would allow loads to directly alleviate contingency and other reliability events on the system to better increase resiliency.

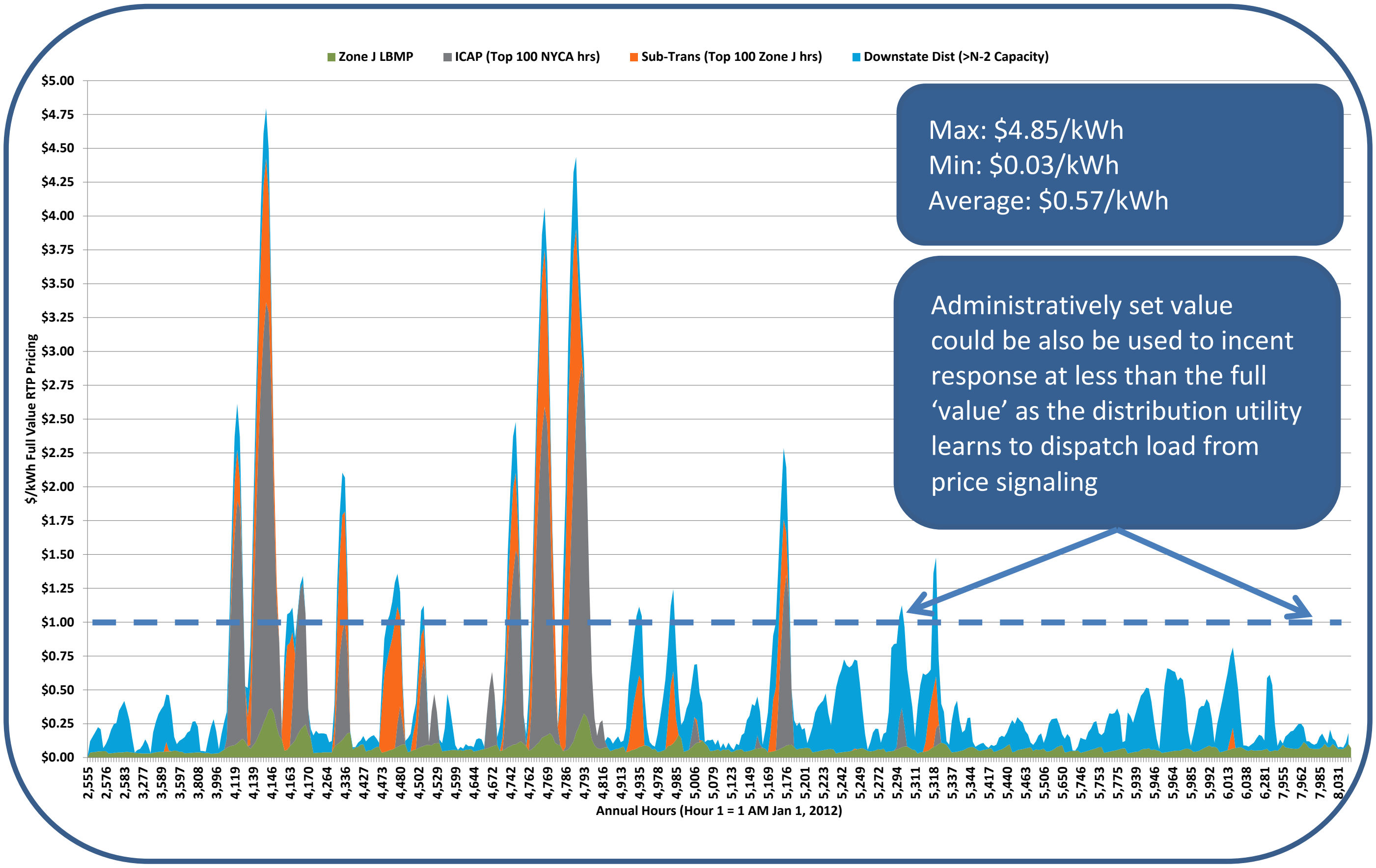
Credits on network subscription charge. Several of the components in the dynamic price do not directly offset current utility costs because they are based on *forward looking avoidable costs*. As described in **Chapter 2**, the sub-zonal transmission and distribution capacity costs are forward looking capacity costs and are not actually incurred until a utility makes an investment. Therefore, for customers in constrained areas with local dynamic prices in the sub-zonal and distribution system, the utility would be collecting money that is not directly offsetting costs. We propose that this 'over' collection or revenues be used for bill credits for FVT participating customers in the locally constrained areas. The bill credit should be used to reduce the network subscription charge.

In the FVT option that includes the externality cost, there is also an additional revenue stream that is not directly offsetting costs. We propose that this revenue also be returned to customers through a credit that would in part offset the network subscription charge of customers. Some of the externality revenue is used for mitigation programs such as renewable energy and energy efficiency and should be netted from the externality cost or societal adder. Therefore, including the externality increases the volumetric charges ($/kWh) and reduces the network subscription charges ($/kW).

'Circuit breakers' and 'price adjustments.' Given the potential volatility of loads and prices when operating under a dynamic price, it would be appropriate to have certain types of pricing flexibility and pricing limits. However, we recognize there are also problems with artificial caps and mechanisms in the price formation process. Also, the price for distribution capacity is not a competitive market, and if there is pricing flexibility it should only be *downward* flexibility. This can be achieved by either capping the maximum price offered or reducing prices if load reacts significantly to a high price and the local network is safely below the operating threshold. In any case, these adjustments should be based on published and transparent rules and not subject to utility discretion.

Dynamic pricing will be an iterative and automatic process due to technology adoption, and the maximum full value dynamic prices may not be necessary to achieve system efficiencies. Lower administratively set rates reflective of system values during certain times/locations can be sent and the response by load can be observed to see if efficiencies or value can be achieved at lower cost. **This concept of achieving the highest value for lowest cost should be an underlying principle throughout.**

Figure 23: Example of dynamic hourly marginal pricing for 2012 in a distribution capacity constrained area in a Downstate area which has both market (Zone J LBMP + NYCA ICAP) supply charges and the marginal 'distribution value' from avoidable/deferrable distribution and sub-transmission capacity costs.



3.3 Illustrative Full Value Tariff

Using the principles and approach defined above along with using the fundamental economic rate as a theoretical underpinning, we develop illustrative formulations of the FVT based on a downstate (Consolidated Edison) and an upstate utility's (National Grid) embedded and marginal cost of service studies, historical market supply charges, and underlying historical rate and cost structures. For each utility, we formulate a FVT with and without adding externalities to the dynamic price. All formulations use an example in a constrained local T&D zone assuming a forward looking distribution capacity marginal cost of ~$78/kW-year for ConEd and ~$68/kW-year for National Grid along with a sub-transmission marginal cost of ~$43/kW-year for ConEd and ~$23/kW-year for National Grid. The rates and bill credits are designed so that if they were adopted by all residential customers in each utility, they would collect the same revenue as the existing tariffs. This means that the utility would not collect revenues in excess of what it would have collected under existing rates, i.e. 'revenue neutrality' is maintained.

The following table shows the FVT charges for these illustrative rates. The detailed derivation of the rates is provided in the appendix along with references to sources. In Table 3 it is important to note that only the average annual dynamic price is provided and that the hourly dynamic price signal is both higher and lower depending on the hour (for example, see the figure above).

Table 3: Illustrative full value tariff rates in T&D constrained areas (Upstate and Downstate example utilities)

	Part 1: Customer Charge	Part 2: Network subscription Charge	Part 3: Dynamic Price
Units	**$/customer-month**	**$/proxy kW-month**	**Average $/kWh**
Downstate; No societal adders	$20.67/customer-mo	$14.05/proxy kW-mo	$.1153/kWh
Downstate; With societal adders	$20.67/customer-mo	$8.17/proxy kW-mo	$.1504/kWh
Upstate; No societal adders	$23.89/customer-mo	$4.46/proxy kW-mo	$.0647/kWh
Upstate; With societal adders	$19.99/customer-mo	*$0.00*[48] proxy kW-mo	$.0938/kWh

As can be seen in Table 3, the rates with externalities (i.e. societal adders) have lower network subscription charges than their externality-free counterparts. This is due to the additional revenue collected by the dynamic prices (which are higher due to adding the externalities as a flat $/kWh societal adder) and credited against the network subscription charge. Further, it is worth noting that the customer charges presented do not match the current filed tariff customer charges. Those that are provided match the utility filed embedded cost of service numbers. If ~$20/customer-month charges are deemed to be too high compared to current

[48] The network subscription charge is zero because the refund from the over collection of dynamically priced revenues including forward looking avoidable distribution and sub-transmission capacity prices is greater than the network subscription charge, which is then used to reduce the customer charge.

levels, some of these per customer charges could be allocated to the network subscription charge. However, this has the trade-off of reducing some of the economic efficiency in the FVT.

3.4 Full Value Tariff Considerations

We believe that the FVT allows for a fully technology agnostic rate that can evolve and be tested as REV is implemented and the DSP model matures to enable a robust CleanTech ecosystem in New York with multiple distributed energy resource offerings. As with any rate design, there are a number of considerations that should be made before offering a rate.

A preliminary review of the key issues that are commonly evaluated is provided below:

Customer equity issues: There are a number of potential customer equity issues when introducing any new rate, which we believe are manageable even if proposing a dramatic change to the existing rate design. One possible issue is **bill impacts** for existing customers if they are switched to a default FVT. A preliminary assessment of bill impacts is included in the chapter on transition paths, which demonstrates that there are limited bill impacts across customers of different sizes. This is primarily due to the size-differentiated network subscription charge, which collects approximately the same amount of revenue based on the customer size. Another possible equity issue is exposing customers to uncertain or **volatile energy prices**. The ESCO market has already developed numerous products available to customers for addressing volatility, and we believe that if the ESCO market embraces this rate they will similarly offer price volatility mitigation services. Under an opt-in formulation of the FVT, these equity issues would be lessened or eliminated as the customer freely chooses to opt-in to the FVT.

Economic efficiency: By design, the FVT is an extremely economically efficient rate and provides area- and time-differentiated marginal prices equal to marginal cost. In addition, a size-based network subscription charge collects utility embedded costs based on a fair allocation methodology linked to a customer's use of the grid.

Enabling conditions/implementation costs: In order to implement the FVT, customers will need appropriate metering technology as well as technology that enables their load to respond automatically on an hourly basis without active customer participation. The FVT with hourly dynamic pricing is unlikely to be implementable if an individual has to manually respond to price signals. Instead individuals can program their preferences into a control system, which then manages and optimizes load in response to those preferences and the underlying dynamic prices. Further, it would be possible to develop a rate that simplifies the dynamic price to TOU, or time-of-use plus critical peak pricing (CPP), that could be implemented without responsive control technology. However, this reduces the efficiency of the rate and limits the participation of some technologies that would otherwise be economic.

Stakeholder acceptance and understanding. There are two aspects of the FVT rate that would be new to customers: the network subscription charge and the dynamic price. Both would require customer outreach and education to provide understanding. The FVT is based on cost principles, is fair, and should be acceptable to most customers given that the overall bill impacts would be managed with new enhanced opportunities to save.

Utility revenue/financing risk. By introducing a network subscription charge, utility revenue for embedded cost collection will become more stable. While outside the scope of this study, limiting the risk of embedded cost collection could lower utility costs overall through better utility financing. In addition, dynamic pricing will encourage better asset utilization, which will also reduce ratepayer costs.

Encouragement of technology adoption. The FVT is designed to encourage customer adoption of load management technologies by providing a viable business model based on the underlying value of customer's load changes and net injections to the grid. This is the focus of the next section of this chapter.

3.5 The Case for Technology and Market Offerings

The proposed FVT can enable a number of DER technologies and market offerings within a broader CleanTech ecosystem. This market transformation and technology acceleration can occur because the FVT can provide compensation for the value provided to both customers and the grid. In this section we examine the business cases for several DER technologies using a 'smart home' and FVT rate model. Using the model, we quantitatively examine the value proposition of several DER technologies for mass market customers under the FVT. These models are further described in the study appendix. Specifically, we compare customer bill savings for various technology investments to the value the technologies provide to the grid. Higher bill savings for certain technologies are an indication of higher expected technology adoption or behavioral changes based on potential savings.

We find that under the FVT there continues to be a compelling business case for solar PV in high value locations. The FVT also creates new business models for emerging technologies such as 'smart' charging of electric vehicles, storage technologies, and automated home controls like 'smart' thermostats. This shows that the FVT enables the full ecosystem of innovative technologies and provides a system of rewards for behavior that can maximize the value to the underlying grid and help achieve the REV goals.

3.5.1 DYNAMIC VS. STABLE PRICING

The FVT is dynamic. Its spatial and temporal granularity sends the appropriate signals to reduce load and/or increase generation during key times and at key high-value locations. While this granularity provides the dynamic price signal that is reflective of the underlying marginal costs of the grid, price signals also need to be stable in order to create longer-term investment signals for DER technologies. The dynamic nature of the FVT will enable DER technologies and customer behavioral changes in the highest value locations and times, thus maximizing benefits to the customer and the grid. Further, we believe that the FVT is stable enough to incent the adoption of certain technologies for the following two reasons:

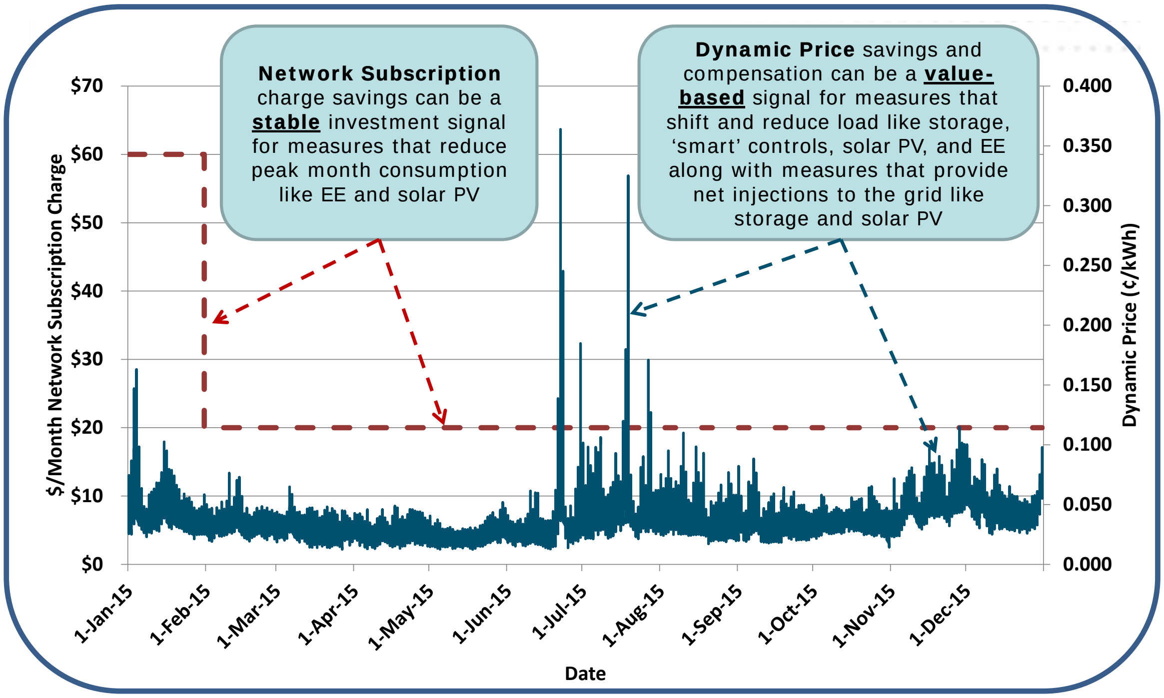
1. The FVT will result in dynamic prices that will be predictable in overall magnitude from year to year. Stability does not require that the rates be uniform over the entire year. Energy prices that vary hourly can still promote investments to the extent that future returns or bill savings can be forecast with some confidence.

2. The FVT's network subscription charge can result in stable, predictable, and transparent savings over time. For example, if mass market customers on the FVT install solar PV or certain energy efficiency measures that reduce monthly consumption during peak months, e.g. July or August, they could experience savings from both the dynamic price signal and the reduction in the network subscription charge[49]. The customers' subscription charges would be consistently and predictably lower due to reduction in monthly consumption. This would result in a very stable and longer-term investment signal on top of the underlying dynamic pricing.

The overall effect is that a new portfolio of high value solar PV, energy efficiency measures, advanced demand response, and new DER technologies like storage and 'smart' controls can contribute to both saving customers money and providing full value to the grid, all through the animation of market forces. Further, this can all be achieved under the backdrop of collecting the grid's embedded costs to maintain and operate the network in a fair and equitable manner under the proposed FVT structure.

[49] Under the FVT there can be a lag between when the usage reduction starts, and when the network subscription portion of the bill is reduced. If the customer's highest monthly usage occurs, for example, in July, then usage reductions that start in May will not affect the network subscription charge for two monthly billing cycles. Conversely, any usage reductions the customer can attain in July can result in 12 months of network subscription charge reductions even if the usage reduction does not persist for a full 12 months. This results in customers being able to achieve savings in excess of what was available under historical rates.

Figure 24: Under the FVT, dynamic prices are used as value-based compensation for a number of activities and customer measures such as energy efficiency, solar PV, storage, and other load shifting or reduction technologies. The savings from network subscription can be a stable, longer-term investment signal for measures that reduce peak month consumption like solar PV and EE. This is shown in an illustration below.



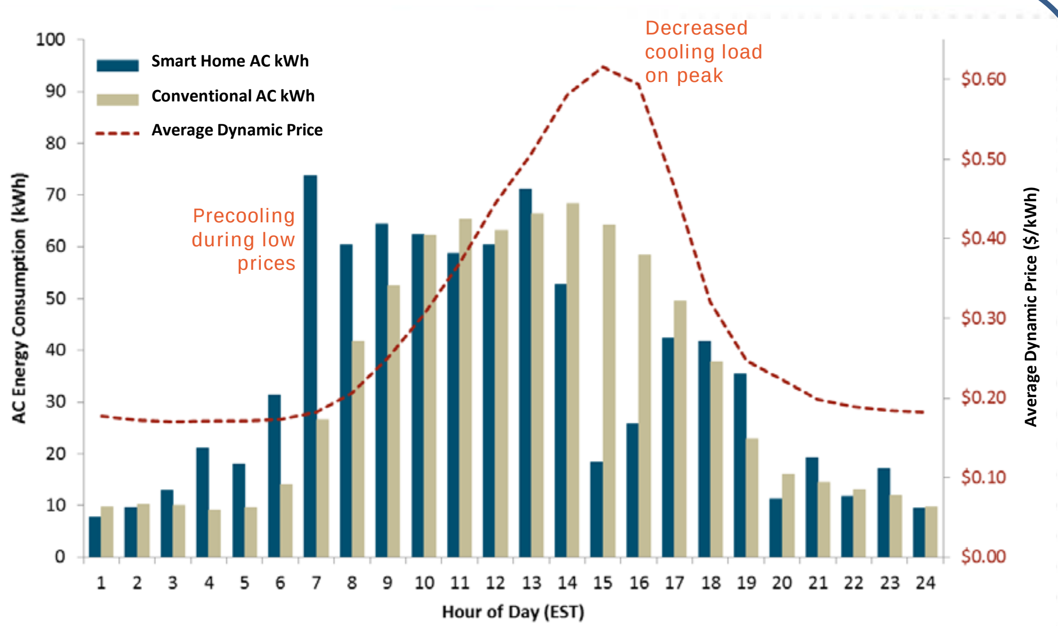
3.5.2 QUANTITATIVE RESULTS

The results below show that based on our 'Smart Home' model and FVT rate analysis, there is a compelling business case for participation in the FVT for a whole host of technologies. For example, Figure 25 demonstrates how 'smart' thermostats that can precool homes during low price hours can save customers money in the higher cost hours. As shown in Figure 26, solar PV under NEM compensation aligns reasonably well with its actual system value in high value locations, i.e. with high sub-transmission and distribution level pricing.[50] Also, given the design of the network subscription charge, different technologies can realize customer bill savings in <u>excess</u> of their actual system value. This is an <u>explicit</u> design choice to encourage energy efficient outcomes, customer technology adoption, and market transformation as per the REV

[50] However, in a location that is not high value NEM overpays based on the actual value provided.

Track 2 White Paper rate design principles. This means that a strong and stable energy efficiency signal is part of the FVT design along with providing for more value-based dynamic pricing and a fairer, more equitable way to recover the network's embedded or fixed costs.

Figure 25: With more time variant and efficient rates along with the advent of cheap distributed controls new and innovative ways are available to manage load 'smarter' by responding to dynamic prices leading to increased benefits and new system value. Under Dynamic Pricing customer comfort can be maintained with significant changes in electricity use observed such as pre-cooling with a 'smart' HVAC/thermostat in the morning when Dynamic Prices are lower which requires less cooling in the afternoon, when Dynamic Prices are higher resulting in a flatter load shape and bill savings. The results for a 'smart home' in ConEd for average July/August HVAC use are presented below.



Smart AC assumptions: 2 degrees of precooling; Otherwise, $1/°f customer comfort penalty in each hour with a set point deviation; accurate day ahead prices and weather forecasts.

Figure 26: 'Smart home' technologies can realize significant customer savings vs. a 'regular' house as prices become more value-based, i.e. time-variant and area-specific, under the proposed FVT. Customer bill savings from both dynamic pricing and network subscription charge reductions from dispatchable and non-dispatchable[51] technologies are shown below for both a high value location, i.e. in an illustrative T&D constrained zone, and zero local value location, i.e. non-T&D constrained zone, for both Consolidated Edison and National Grid.

E3's Smart Home Model

E3's Smart Home model simulates the customer and utility system benefits of controllable flexible loads under any user defined retail rate price scheme like the FVT including TOU, tiers, subscription charges, and real-time pricing

A 2,500 square foot, 3-bedroom New York specific home is modeled with a generic home energy control device that:

- Sends and receives data signals to/from the electricity grid
- Learns customer preferences and behavior
- Controls electricity use and generation of home appliances

Bill savings (high local T&D value) $/year
Bill savings (zero local T&D value) $/year

	Rate Option	Solar Roof (75% Usage Offset)	A/C EE 25% Savings	Price Induced Load Shifting	Smart HVAC	Battery Storage	Smart Electric Vehicle
ConEd	Existing Rates	$1,253 / $1,253	$112 / $112	No Savings	No Savings	No Savings	No Savings
ConEd	Current Optional TOU	$1,467 / $1,467	$136 / $136	$50 / $50	$98 / $98	$357 / $357	$202 / $202
ConEd	Full Value/Smart Rate	$1,179 / $742	$146 / $93	$274 / $(74)*	$236 / $151	$430 / $305	$141 / $133
ConEd	Full Value/Smart Rate + Societal Signal	$1,300 / $863	$142 / $89	$260 / $(74)*	$229 / $144	$404 / $280	$123 / $122
National Grid	Existing Rates	$664 / $664	$51 / $51	No Savings	No Savings	No Savings	No Savings
National Grid	Current Optional TOU	$582 / $582	$44 / $44	$10 / $10	$8 / $8	$31 / $31	$7 / $7
National Grid	Full Value/Smart Rate	$587 / $425	$51 / $33	$48 / $12	$156 / $50	$350 / $144	$192 / $48
National Grid	Full Value/Smart Rate + Societal Signal	$723 / $562	$61 / $43	$37 / $24	$149 / $43	$328/ $122	$184 / $39

*Price elasticity results in bill increases because of increased consumption due to lower prices.

There are several key takeaways from the results above:

+ The value proposition for solar PV and EE measures remains strong under the FVT in a high value location.

[51] In the formulation of the FVT with a societal adder, a flat ¢/kWh societal price signal is added on top of the dynamic prices. For load shifting or dispatchable technologies like 'smart' thermostats, battery storage, and 'smart' electric vehicle charging, the FVT with a societal adder may result in bill savings less than what is achieved under a FVT with no societal adder. This is because load shifting is driven by the relative difference between prices in high vs. low cost hours, i.e. peak vs. off-peak ratios, rather than the absolute price levels.

+ With the addition of a dynamic price signal, the full value from certain 'smart home' technologies can be achieved.
+ Savings from both the dynamic price signals and the reduction in the network subscription charges can be significant.
+ Load shifting technologies under the FVT realize customer savings on par with the actual value being provided to the grid due to the formulation of the dynamic price signal.
+ There are counter-balancing effects with adding a societal signal or adder to the dynamic price in the FVT. A societal signal or adder increases the volumetric energy charge a FVT customer would pay, which is offset by a lower network subscription charge (this is done to collect the same amount of money in the rate design, i.e. maintain revenue neutrality).
    - This results in more 'smart home' technology savings from the dynamic pricing, but <u>less</u> in savings from the reduction in the network subscription charge. This can then result in lower overall bill savings with the FVT that includes a societal adder vs. the one without for certain technologies or measures based on their impacts on monthly consumption in the peak month vs. their impacts on dynamic pricing.

The bill savings demonstrate the value proposition from the perspective of the customer and associated technologies or businesses. The annual bill savings for non-dispatchable technologies[52] are shown in Figure 27 as a percentage of the actual value being provided to the grid ($ bill savings are divided by the marginal cost dynamic prices). The results are shown for both a high value T&D constrained area and a lower value area with no T&D constraints. As can be seen, the non-dispatchable technologies like solar and EE measures are compensated at over 100% of their value because the FVT allows embedded cost savings from reducing consumption in the peak month by way of a lower network subscription charge. This was an explicit design choice to promote energy efficient outcomes as per the REV rate design principles.

[52] Load shifting technologies are not shown below due to the fact that the dynamic price signal in the FVT is designed to reflect actual marginal cost or value to the grid. Load shifting technologies therefore respond to the dynamic prices in the FVT to optimally move load from higher cost hours to lower cost hours which provides value on par with the bill savings achieved.

Figure 27: In high value locations solar PV and the energy efficient A/C unit examined are being compensated at roughly equal levels under existing rates and the FVT. However, in locations with zero local or T&D value existing rates significantly overcompensate for the value provided to the grid. Under the FVT design, these technologies and measures are still being promoted and encouraged in every case.

E3's Smart Home Model

E3's Smart Home model simulates the customer and utility system benefits of controllable flexible loads under any user defined retail rate price scheme like the FVT including TOU, tiers, subscription charges, and real-time pricing

A 2,500 square foot, 3-bedroom New York specific home is modeled with a generic home energy control device that:

- Sends and receives data signals to/from the electricity grid
- Learns customer preferences and behavior
- Controls electricity use and generation of home appliances

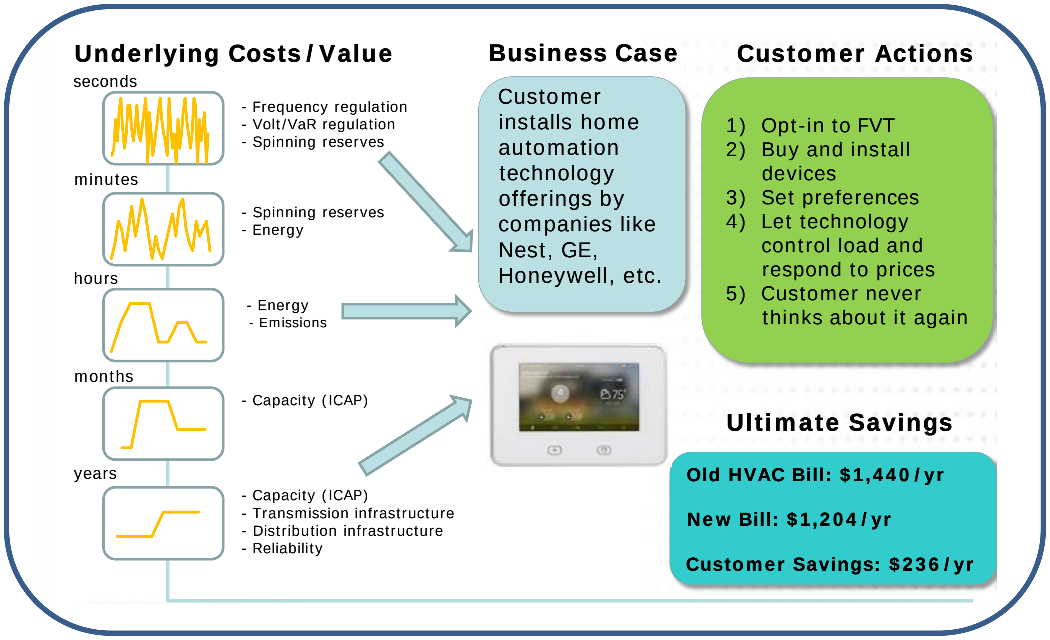
Bill savings as % of Grid Value (high local T&D value) $/year
Bill savings as % of Grid Value (zero local T&D value) $/year

	Rate Option	Solar Roof (75% Usage Offset)	A/C EE 25% Savings
ConEd	Existing Rates	131% / 243%	118% / 270%
ConEd	Current Optional TOU	154% / 285%	143% / 327%
ConEd	Full Value/Smart Rate	124% / 144%	154% / 224%
ConEd	Full Value/Smart Rate + Societal Signal	137% / 168%	150% / 215%
National Grid	Existing Rates	122% / 175%	108% / 171%
National Grid	Current Optional TOU	107% / 153%	93% / 148%
National Grid	Full Value/Smart Rate	108% / 112%	107% / 111%
National Grid	Full Value/Smart Rate + Societal Signal	133% / 148%	129% / 146%

3.5.3 CASE STUDIES

In this section we present five case studies highlighting the different value propositions of the FVT from the perspective of five different types of technology and market-based offerings. We believe this demonstrates that there is a compelling business case from both the market and the customer points of view that can help create and sustain a robust and vibrant CleanTech ecosystem, while maintaining and enhancing the grid.

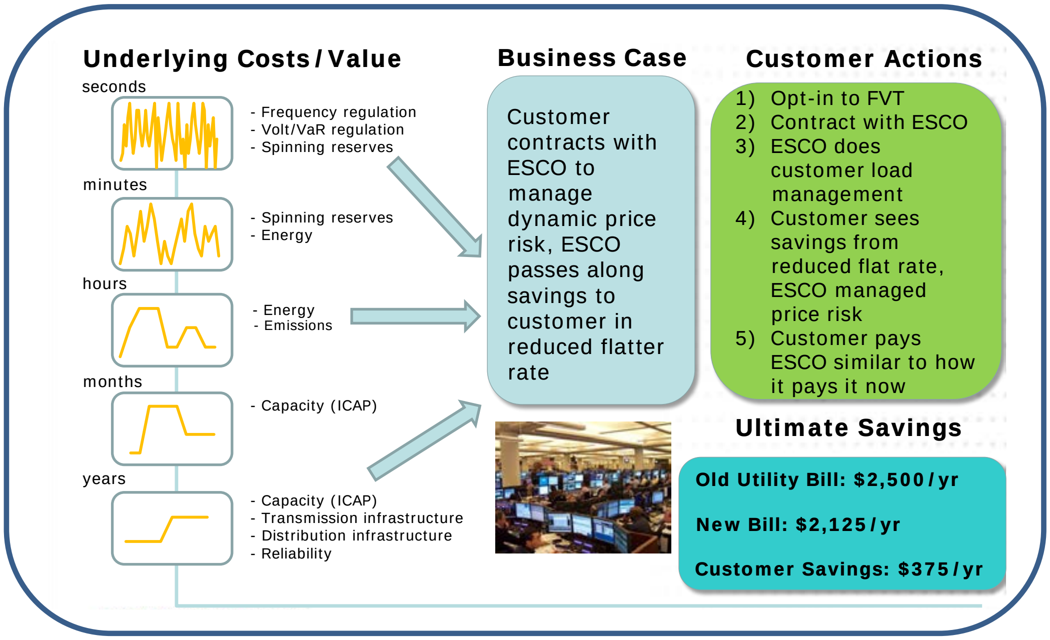
Figure 28: Case 1: Under the FVT automated technologies can take advantage of the dynamic price signal to save customer money under preset customer preferences.



Smart home automation and thermostat controls will be able to optimize electricity usage to balance a residential customer's 'comfort' preferences with their desire to reduce bills. This automation of the load response is expected to result in much higher participation from residential and small commercial clients, which historically have been difficult sub groups to target for EE or other DER programs. The devices could even suggest behavioral changes which would result in savings or new appliances or technologies which could save the customers money. This could also result in new markets and advertising potential for emerging technology companies.

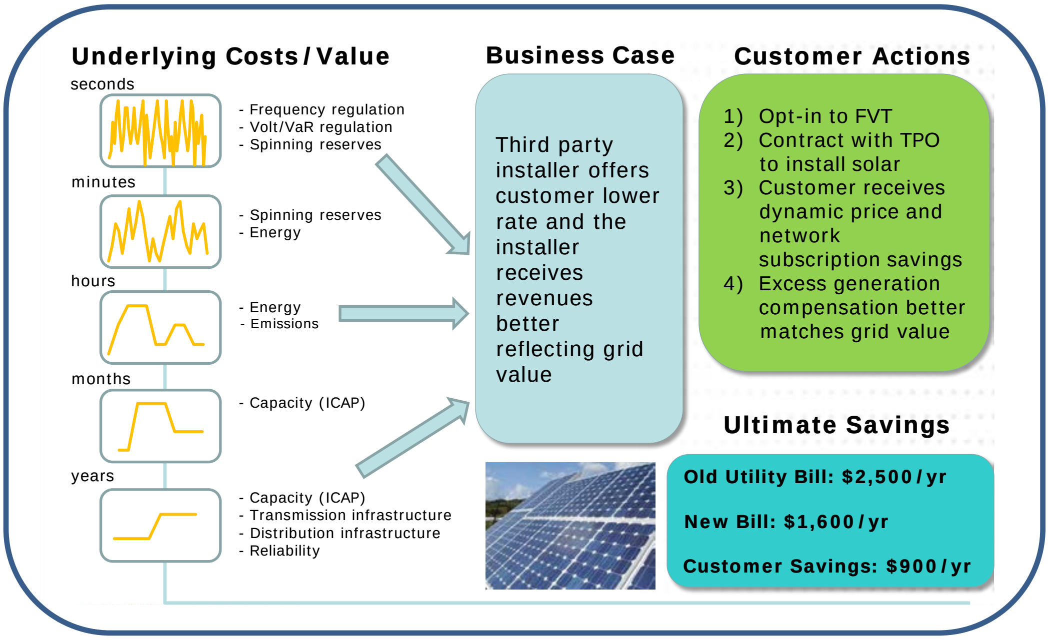
These technologies will be broadly applicable but particularly beneficial in areas with high dynamic prices or customers with more flexible use patterns.

Figure 29: Case 2: Under the FVT energy service companies (ESCOs) or DER aggregators can contract directly with the customer and manage the dynamic price risk and other load management services.



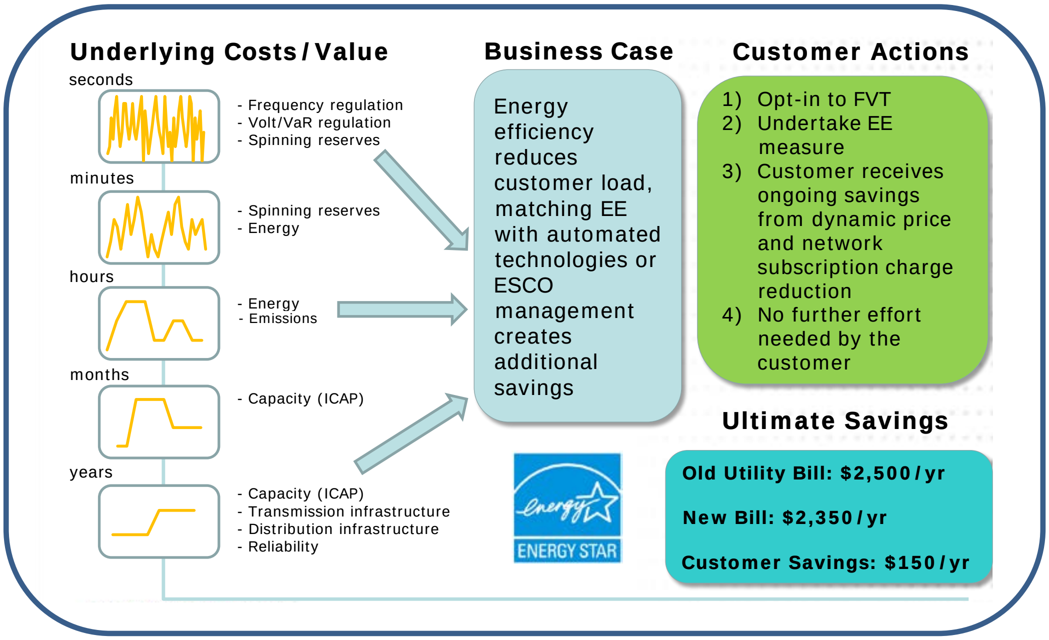
The FVT will also provide more opportunity for traditional ESCOs or DER aggregators to contract with customers and facilitate and promote participation in the market whether or not sophisticated automated technology is used or not. These aggregators will be able to promote and explain the value proposition to commercial and industrial customers and create more stable revenues or different models to attract different types of end-users in high value FVT areas.

Figure 30: Case 3: Under the FVT solar PV third party owners (TPO) can continue offerings with immediate upfront customer savings.



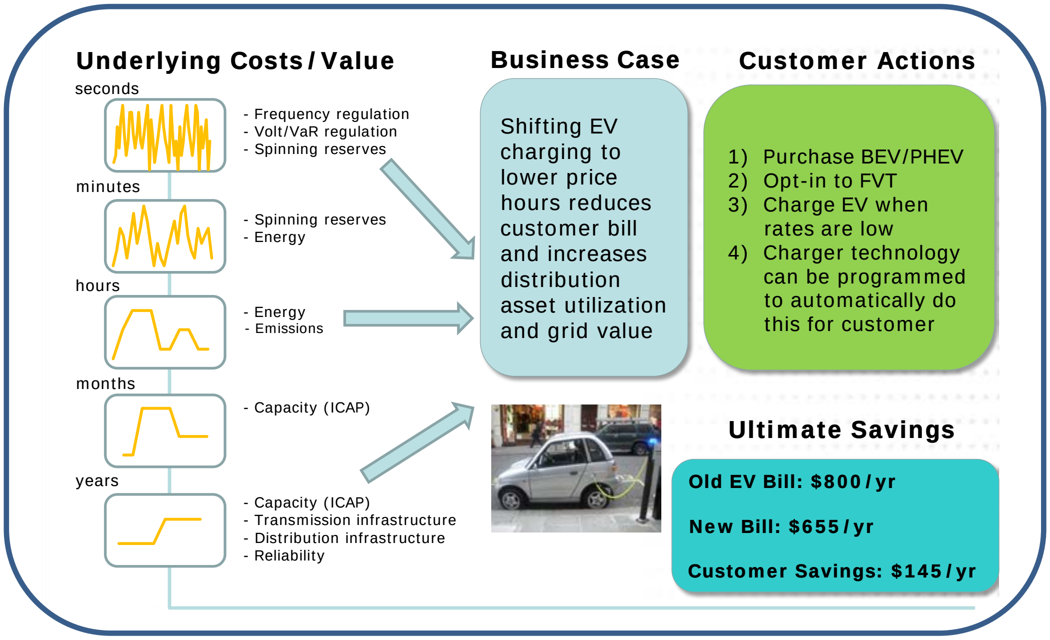
Under the FVT, solar project developers with third party financing options will be able to offer solar customers bill savings while taking the revenue streams associated with the grid value. This model could provide more value than NEM in some areas, and is a more sustainable long term market because the compensation is connected with the grid value that the solar provides. By linking compensation more closely to the actual underlying grid value, regulatory caps or limits on installed solar PV capacity may no longer needed and the regulatory risk of solar projects is reduced.

Figure 31: Case 4: Under the FVT a new, higher value portfolio of energy efficiency measures may be viable.



ESCOs which specialize in providing energy efficiency services may be able to sell higher-value portfolios of building improvements or appliance upgrades with the combination of the subscription charge and the dynamic price. Active ESCO EE program management could target or co-sell automated technologies as well as identify new market areas where products could be highly cost-effective. Having a differentiated price signal would allow for innovative combinations of EE and other DER resources, which could also allow the EE providers to sell and promote more high cost measures that have historically not been attractive under the previous rate structure. For example, building shell and HVAC energy efficiency measures will have greater value under the FVT as compared to current rate structures.

Figure 32: Case 5: Under the FVT smart charging of electric vehicles becomes more economic along with other types of storage technologies.



The signal for time sensitive and dynamic charging of electric vehicles would become much more substantial under FVT. This would encourage the adoption of new automated charging which would be responsive not just to the time of the day but the location of the car in the grid system. Shifting EV charging to lower price hours and avoiding short duration capacity driven peak pricing could provide significant benefits if and when electric vehicle adoption scales.

4 Initial Steps to a Full Value Tariff

There a whole host of considerations that will have to be identified, explored, and addressed with moving toward a FVT. Our main focus and proposal in this study is to implement the FVT as an initial opt-in 'smart' rate along a longer term transition path ending in the FVT becoming the default tariff. It is, however, also worth examining several different types of initial steps that could be taken on the path toward full FVT implementation. In this chapter we present several near-term options or transitional steps that can be undertaken at low risk including potential reforms to the current NEM tariff as well as continuation of existing utility programs and practices.

These potential low risk transitional steps have the benefit of minimally disrupting traditional customers and existing retail rate design structures. This is because the focus is more on distribution utilities procuring high value DERs to avoid or defer specific projects with targeted peak load relief rather than mass customer participation in managing the grid. These transitional steps can consist of opt-in retail rates or programs such as credits for localized DR-type program participation and initial opt-in 'Smart Home' or 'Smart Business' rates that can be made to be default for customer-generators. We present below several different initial steps that can begin the transition.

4.1 Offer the Full Value Tariff as an Opt-In Rate for Mass Market Customers and Make it Default for New NEM Customers

We believe that offering the FVT as an initial opt-in rate, i.e. a 'Smart Home' or 'Smart Business' rate is the preferred first step on the transition toward full implementation. We believe this represents a low risk option that allows the FVT to be tested and assessed under real world conditions. There is low risk because if there is little or no interest in opting into the FVT then the status quo continues, and conversely if there is significant interest and participation the FVT design has built in 'circuit breakers' and rules to manage load response and prosumer net injections onto the grid.

We first begin by providing a simple example of a mass-market customer opting into the FVT highlighting the differences between a customer that responds to the FVT and one that does not to demonstrate the opportunity for savings and the low risk for negative outcomes.

Table 4: Opt-in FVT customer walk-through comparing a customer that responds to the FVT and one that does not.

Opt-In FVT Participant that Responds	Opt-In FVT Participant: No Response
(1) Opt-in to FVT.	(1) Opt-in to FVT.
(2) Buy control technology or have ESCO/aggregator provide an offering with an agreement.	(2) No technology.
(3) Receive bill credit at beginning of summer in exchange for being subject to higher dynamic prices.	(3) Receive bill credit at beginning of summer in exchange for being subject to higher dynamic prices.
(4) Customer saves on bill as technology responds to Dynamic Pricing based on preferences and willingness to change behavior or end uses, which may be pennies every day with occasional spikes.	(4) Customer does not change behavior.
(5) Annual true up with amount paid or collected is in variance with bill credit and utility revenue requirement.	(5) Annual true up with amount paid or collected is in variance with bill credit and utility revenue requirement.
(6) Customer continues to remain on FVT.	(6) Customer bill with the bill credit and dynamic price payments about the same by design as before opting-into the FVT.
	(7) Customer opts-out or does not with no major issues.

The above example illustrates the opt-in nature of the FVT for retail customers under this transitional structure. This could be taken one step further by making the FVT a *default* tariff for <u>new</u> NEM customers. In other words a customer newly installed on-site generation would be defaulted onto the FVT, which as we demonstrated in the previous chapter would have ramifications vs. the current existing rate and NEM structure. The benefits would be that NEM generation would be compensated more on par with its value to the grid and the issue of under recovery of utility costs to serve and potentially inappropriate shifting of costs to other customers could be mitigated. An additional alternative is to initially offer a rate with a network subscription charge only, without the dynamic price. The advantages of this alternative is that it can be implemented without advanced metering infrastructure for mass market customers and it does not require a significant amount of utility or customer sophistication.

Table 5: Pros and cons of the FVT being opt-in for retail customers and default for new NEM customers that install onsite generation.

Pros	Cons
+ Relatively easy to implement, non-NEM customers (i.e. 99% of customers) do not need to do anything and are essentially not impacted. + Should move toward a system where customer generation is paid at its value. + Allows for innovative technologies and market offerings without the risk of massive disruption of the existing relationship between traditional customers and the network if the FVT is opt-in.	+ Small numbers of customers participating and engaging in new marketplace. + Enabling metering technology will be needed for those that opt-in. + Certain near-term adoption goals for solar PV may not be met if the compensation system switches from net metering to a new construct.

4.2 Fixed Cost Recovery Mechanism for NEM Customers

This represents a near-term solution that can be applied to address the potential cost shift issue of NEM. This would be a mechanism that would recover any utility under recovery of fixed costs from customers that participate in NEM by installing customer-sited generation. This mechanism should be assessed on total customer gross consumption or total DER generation depending on its design. Depending on the level of these types of mechanisms, there could be significant opposition and a chilling effect on customer DER adoption. It is likely that any such mechanism would likely have to be waived until the DER market has more fully matured and the market transformed.

Table 6: Pros and cons of a fixed cost recovery mechanism for NEM customers.

Pros	Cons
+ It is administratively simple to set and can be calculated from customer cost of service analyses and reduction of fixed cost recovery due to onsite customer generation. + Can be waived for a number of years until adoption targets or policy goals are met.	+ Politically difficult and could have a chilling effect on customer sited generation. + Could be too small to prevent cost shifts and cross-subsidization.

Table 7: Illustrative levels of what a $ per kW-month of installed solar PV fixed charge[53] would look like for an average residential customer that install solar PV that offsets 50-75% of their onsite consumption which recovers the embedded or fixed costs that solar PV adopting customer no longer pays after installing solar.

Illustrative $/kW-month for Average Residential Customer	ConEd (50% Solar)	ConEd (75% Solar)	National Grid (50% Solar)	National Grid (75% Solar)
Existing Rates	$10.78	$10.61	$7.09	$7.09
Existing Rates (TOU)	$6.28	$4.66	$2.32	$1.82

4.3 Value-Based Compensation for NEM Customers

Value-based compensation mechanisms like the proposed FVT can decouple compensation for customer generation from customer electricity usage, which allows for one less conflicting rate design objective and allows for more flexibility in DER compensation over time since it is not tied to the prevailing retail rate. In other words the customer would receive a payment based on the value of its onsite generation while paying for its gross electricity consumption at the prevailing retail rate. These types of mechanisms can facilitate transparency of cross-subsidies and certainty of compensation for customers.

Certain value components can be short or long term, i.e. short-term dynamic price signal that varies by location and time plus a potentially longer-term stable renewable energy credit (REC)

[53] These illustrative charges were developed based on the amount of residual embedded or fixed costs that would still have to be collected after an average residential customer installs solar PV. This was based on existing rates and assumptions regarding how much embedded or fixed costs are collected before and after installing solar PV for that average residential customer.

signal for investment or policy purposes if there is ‘missing money’. This ‘missing money’ represents the revenue needed to finance and invest in certain longer lived DERs like solar PV when the market is first being established and transformed. This REC signal can be set administratively or through a competitive reverse auction mechanism (RAM) or request-for-proposal (RFP) mechanism[54] to reach New York policy goals and allow for market adjustment and evolution based either on quantity targets (e.g. X MWs per year/month) or price/budget targets (X $ of incentive money/budget or reserve price).

A competitive mechanism would most likely still be paid for by ratepayers, i.e. the Public Purpose Charge/System Benefits Charge, but it could allow for greater value at lower cost in a more transparent manner vs. using a NEM ‘one-size fits all’ compensation mechanism.

Given expected solar PV and DER cost declines and forecasted increases in the value of these resources (i.e. monetized system avoidable or marginal costs) any REC competitive mechanism is assumed to be a <u>short-term</u> tool to enable market transformation that should decline in use or costs over time. The figures below detail how a value-based mechanism for NEM customers could be structured along with detailing how the potential value components could be calculated and built-up on an illustrative basis.

[54] Competitively-bid REC payments for “clean” DER resources serves the purpose of obtaining a given amount of additional clean DG, if tariff rates do not stimulate the socially desired amount. In addition to this, consideration could be given to externality costs in setting “full value” retail rates. That is, when designing fixed and volumetric rate elements to collect total revenue requirements, marginal costs per kWh could be set to marginal social costs (i.e. marginal pecuniary costs plus marginal external costs). In many cases, this would reduce the amount of revenue requirement that is shifted to fixed charges. As noted in the NY DPS Staff’s BCA Framework White Paper, external costs could be estimated as existing marginal compliance costs (already included in pecuniary costs); net marginal damage costs; or set to a level that is equal to the premium paid in REC procurement auctions (such as that suggested above).

Figure 33: Value-based mechanisms can be structured in many different ways.

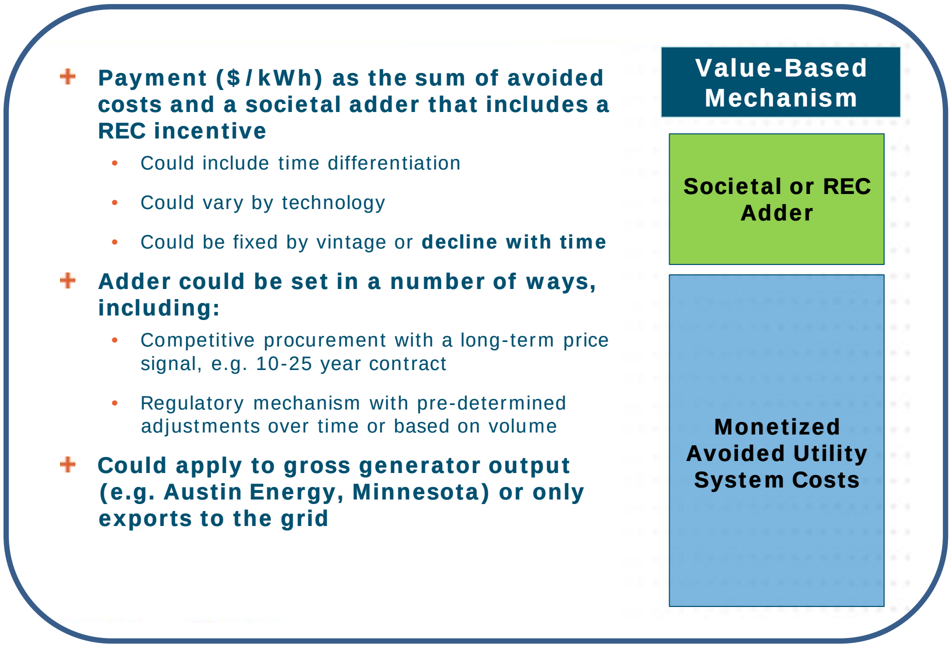


Figure 34: Potential 'values' of solar in random location in ConEd's service territory in 2015 including both monetized avoided costs and societal values.

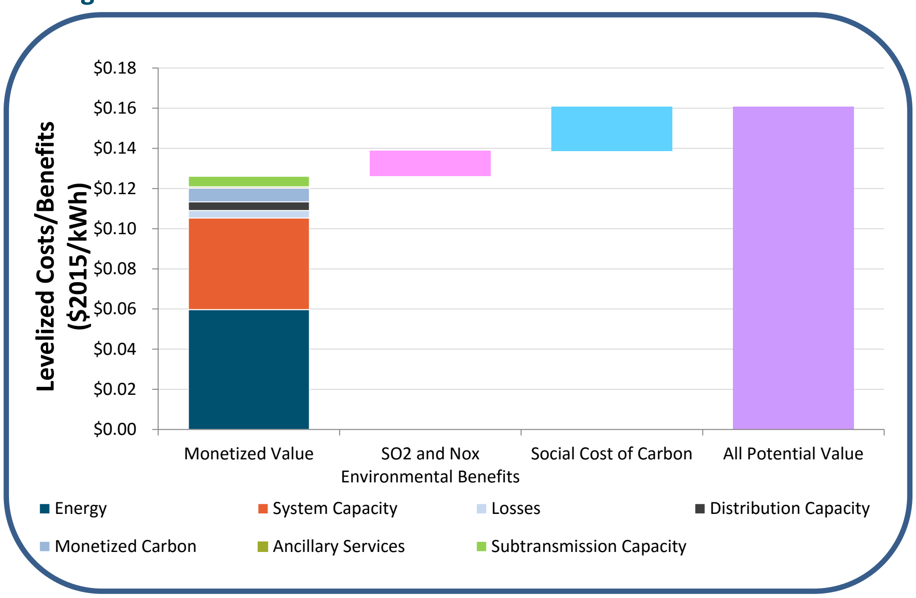


Figure 35: Potential 'values' of solar in high value, targeted local 'hot spot' location in ConEd's service territory in 2015 including both monetized avoided costs and societal values.

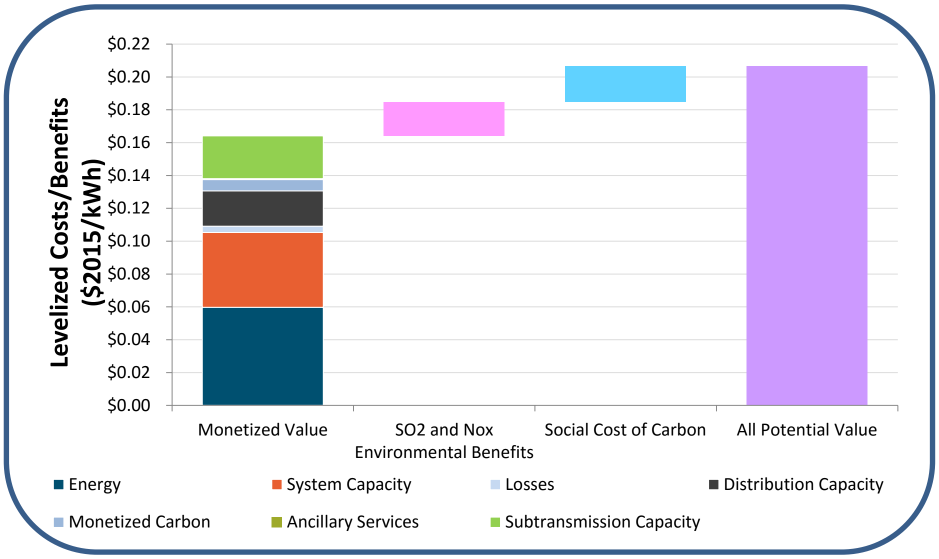
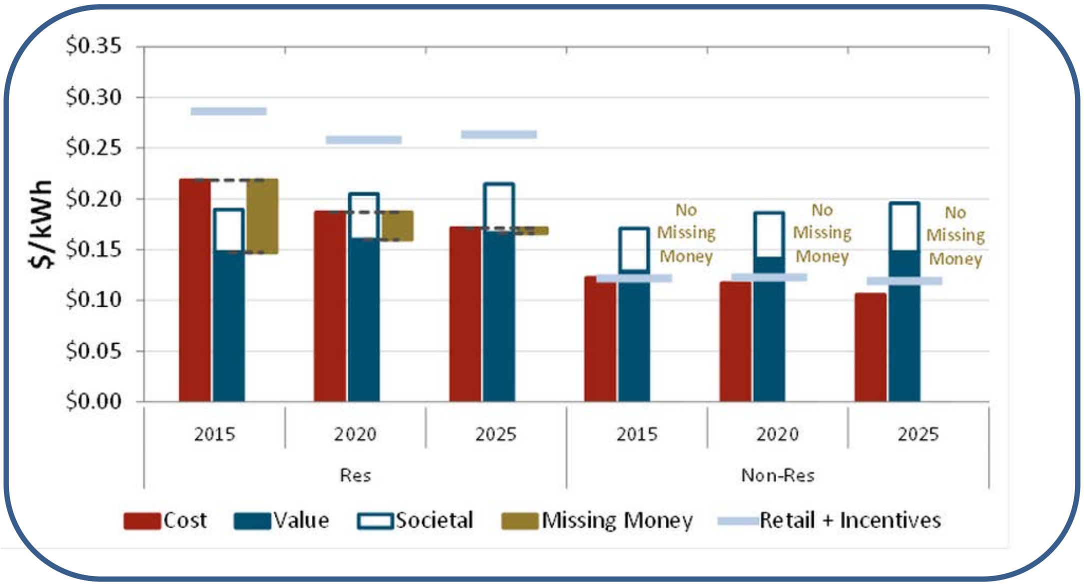


Figure 36: The REC or 'Missing Money' for solar PV currently being paid for by NEM compensation and other incentives is expected to decline over time as solar PV costs decline and its underlying value increases.



4.3.1 HYBRID OR ASYMMETRIC RATE FOR NET INJECTIONS/EXPORTS TO GRID

A hybrid or asymmetric rate can be used as a potential transition step toward full value-based compensation. In a hybrid rate any behind-the-meter generation is implicitly compensated at the prevailing customer retail rate and any exported generation or net injection to the grid is paid at a more value-based rate, e.g. a dynamic price, actual hourly avoided costs, or a proxy avoided cost rate by TOU periods. This represents a compromise solution to the issue of value-based compensation for the full output of customer-sited generation and payment for a customer's gross on site electricity consumption and may not entirely fix the issues with the existing NEM construct. However this could represent a good first step, especially in the early years of market transformation, to transition to a more value-based compensation mechanism.

Table 8: Pros and cons of a hybrid or asymmetric value-based compensation mechanism for NEM customers.

Pros	Cons
+ Separates out generation that is consumed behind the meter vs. net injections. + Does not discriminate between distributed generation and energy efficiency. + Represents the first step in transitioning the current NEM compensation mechanism to a more value-based construct.	+ Enabling metering technology will be needed to do hourly netting. + If meters are not utilized then 'proxy' export factors will have to be created from simulations and other assumptions which could create issues vs. actual performance. + Does not address the full generation of the customer sited generation and the potential for cost shifts and under recovery of fixed/embedded costs remain unless a standby charge or fixed cost recovery mechanisms is introduced. + May not result in highest value DERs being adopted/installed.

4.3.2 VALUE OF RENEWABLES TARIFF / VALUE-BASED CREDITS

Absent moving directly to the FVT as a default rate for new NEM customers, a value of renewables tariff (VORT) or value-based credits (VBC) would represents a large step forward in providing direct value-based compensation to DERs that should help to optimize DER types and locations. This could take the following form:

+ Buy-all/sell-all type of arrangement with 100% of the customer generation compensated based on grid value either on a short or longer-term basis with all gross customer consumption charged at the prevailing retail rate.
    - This can apply to both customer-sited DER generation used to offset host consumption or larger 'community' or 'virtual' DER generation that is not located at the customer premises, but can be used to offset that customer's utility payments.

Table 9: Pros and cons of a value-based credit for NEM customers.

Pros	Cons
+ Explicitly separates out generation produced onsite which is either used onsite or exported to the grid from total consumption consumed onsite. + Represents a major step in transitioning the current NEM compensation mechanism to a more technology agnostic value-based system. + Should allow for 'smarter' types of DERs in higher value locations that can provide the most value to the system. + Minimal impact on non-DER customers as the amount of cross subsidization can be controlled by the compensation mechanism.	+ Enabling metering technology will be needed to compensate for gross customer sited production and customer consumption. + If meters are not utilized then factors will have to be created from simulations. + There will have to be a balance between basing the value on dynamic values to reflect evolving system costs vs. stable values to encourage adoptions.

4.4 Targeted Distribution Utility Procurements

A utility procurement approach to target high-value areas is a transition step that is already being implemented and can be done in parallel with implementing and testing the FVT. This step builds upon existing utility programs and can result in deferral and/or avoidance of real capital projects although alignment of utility incentives and ratepayer/regulator goals need to be explicitly considered. This approach can take the following form:

+ RFPs or auctions of specific DERs to avoid/defer specific distribution capital expenditures and/or operations expenses.
    - 1-3 year PPAs (or longer) or other payments for short-term deferrals and longer 5-10 year agreements for longer-term deferrals or outright CapEx avoidance.

Table 10: Pros and cons of utility procurements of DERs to avoid local distribution capacity costs.

Pros	Cons
+ Builds upon existing programs such as ConEd's BQDM[55] and other types of utility procurements. + Can be used to defer or avoid significant utility capital expenditures.	+ Less market based solution and more command and control. + Requires utility realignment of incentives to encourage DERs vs. traditional utility CapEx to grow/maintain earnings or OpEx which is a pass through cost. + Relatively cumbersome procurement process with a long timeline limits best use to major capital projects with a long lead time.

4.5 Reform of Existing Opt-In TOU Rates

A review of the current mass market opt-in TOU rates in New York indicates that certain rates may be structurally unattractive (total bills may go up given the rate's peak/off-peak definitions or the rate may be too flat with no potential savings value). If these rates form the basis of the first transition step then they should be reformed into a more general 'Smart Home' or 'Smart Business' rate that better reflect the underlying marginal costs of the system and are designed such that they are revenue neutral.

[55] See http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=45800

Table 11: Pros and cons of reforming existing TOU rates.

Pros	Cons
+ Builds upon existing programs and represents a very near-term and gradual step toward the longer-term end states.	+ Does not represent a significant change to how dynamic prices are communicated to customers or compensation paid to DERs. + Enabling metering technology will still be needed.

4.6 Targeted or Local DR/Peak Time Capacity Rebate Programs

Targeted peak time capacity rebate programs build upon existing utility demand response and rebate programs and offer a relatively easy first step on the transition path. However, these programs have several shortcomings that may only get bigger as these programs scale including incentive payments. The greatest shortcoming, however, is the issue of how to determine the baseline of technologies that operate every day such as energy storage or home automation. Further, there are known issues associated with free ridership such as paying customers for behavior or actions they would have undertaken anyway. In general these types of programs can take the following forms:

+ Utility programs that provide peak time rebates (PTR) or peak time credits (PTC) to residential and non-residential customers. Specifically, area-specific DR programs that would give a value-based credit/rebate ($/kW) for local distribution and sub-transmission capacity value in high value local 'hot spot' areas.

Table 12: Pros and cons of utility local DR and rebate programs.

Pros	Cons
+ Incentive or credit based DR mechanisms are popular among customers and less punitive than price based mechanisms. + They build upon existing offerings and other similar types of programs and mechanisms.	+ There are issues associated with determining a customer's 'baseline' usage to compare reductions against in order to determine the credit/incentive amounts, especially for technologies that operate every day like storage and home automation. + Free ridership problem, i.e. paying for incentives without any change in behavior or value added. + Enabling technology will likely be needed such as meters or control technologies. + The customer response to these types of programs have not been as strong or long lasting as responses to more price based programs.

5 Transition Paths to Full Value Tariff Implementation

In this chapter, we outline two illustrative potential longer-term transition paths to implement the full value tariff, along both **gradual** and more **rapid** paths depending on the underlying enabling conditions. Key decisions regarding how REV will be fully implemented need to be explicitly defined (i.e. the scope of REV, the granularity of dynamic prices, the level at which REV should be policy focused, and the enabling conditions needed for implementation) in order to construct an optimized step by step transition pathway.

There are a number of potential building blocks that can be assembled to create the transition steps and strategic implementation pathways needed to reach longer-term REV end states where the FVT is the default rate. However, as described in the previous chapter, it is important to note that many of these building blocks and initial transition steps are equally valid and are not mutually exclusive. They each have various pros and cons in terms of efficiency, ease of implementation, customer acceptance, and advancement of policy goals. The following is a short list of high-level transition step considerations when choosing among different possible implementation pathways.

Transition step considerations:

There are significant differences across the spectrum of rate and FVT design options in terms of their form and impacts. Four key considerations when deciding on a transition strategy include:

- *System cost impact* — are there adequate incentives to change investments and energy consumption that reduce overall system costs?
- Customer *bill impact* — which customers pay more, which less? How much more or less?
- *Incremental cost* — what kind of metering and other communications infrastructure is necessary?
- *Customer acceptance* — how difficult is it to explain and accept the rate design?

5.1 Enabling Conditions

As key decisions are made with REV implementation, each transition step should be examined to see if the enabling conditions have occurred to <u>either</u> accelerate the implementation of REV or maintain a more <u>gradual</u> transition pace. Key enabling conditions include:

- *Customer interest* — how many customers would opt-in to the FVT design?
- *Technology development* — are new technologies or cost reductions in existing technologies changing the transition considerations?
- *Distribution utility evolution* — how are the distribution utilities progressing in terms of incorporating DER into planning and operations?
- *Initial experience* — are the initial REV reforms and programs popular and successful?
- *Policy goals* — is there a more ambitious push on policy goals (e.g., NY Sun and other EE, renewable, GHG, and EV goals)?

Initial transition steps can be implemented immediately, such as offering the FVT as an opt-in 'smart' rate for utility customers. This represents a more gradual change — a **gradual path** — that can be maintained until the underlying enabling conditions warrant broader implementation. Alternatively, if certain enabling conditions are met, **rapid** implementation may be immediately warranted, focusing on specific customer types, market segments, or locations. **In other words the pace of transition can be initially gradual, and if the enabling conditions are met the pace can accelerate and become more rapid.**

The following highlights the differences between the two paths.

- **'Gradual'** implementation pathway with opt-in 'Smart Home' or 'Smart Business' full value tariff based rate designs that do not require all customers to have smart meters, with the vast majority of retail customers being unaffected.
    - Conditions that would indicate maintaining a gradual pathway include:
        - Lower opt-in participation of initial 'Smart Home' or 'Smart Business' rates;
        - Slower technology development;
        - Slower evolution of market platforms and offerings by distribution utilities and ESCOs;
        - Less aggressive policy goals for distributed energy resources.
- '**Rapid**' implementation pathway with the FVT forming the basis of 'smart' rates that is default for prosumers and opt-in for all other customers, which eventually becomes the default rate for all utility customers.
    - Enabling conditions for a rapid pathway are as follows:
        - Higher opt-in participation of initial 'Smart Home' or 'Smart Business' rates;
        - Faster technology development (e.g., rapid adoption of solar PV that may lead to increasing levels of inappropriate cost shifting among ratepayers);
        - Faster evolution of utility market platforms and ESCO offerings;
        - More aggressive policy goals for distributed energy resources.

5.2 General Transition Considerations and Guidelines

It is important to recognize that retail rate design in New York has balanced many issues over the years, ranging from policy to economic and social goals. The current approach is relatively simple, particularly for mass market customers with the trade-offs of averaging time and area specific costs and recovering the majority of costs (both fixed and variable) through volumetric energy charges. There are several issues that are worth considering in any transition toward the FVT, some of which include:

- *Inefficient rates and cost shifting* — retail rates generally do not reflect the underlying marginal or fixed costs of providing electricity services on a cost-causation basis, which potentially leads to inappropriate cost shifting among groups of retail electricity customers.
- *Incomplete coverage of social costs* — retail rates reflect only a fraction of the environmental value of load reduction or clean technology substitution for system energy, largely just the compliance costs — Regional Greenhouse Gas Initiative (RGGI) costs and renewable portfolio standards (RPS) and system benefit charges (SBC) surcharges.
- *Need for a gradualism* — if retail rates were already designed such that kWh, kW, and per customer charges reflected the 'full' marginal cost caused by consuming electricity, including social costs and reflecting spatial and temporal differences in cost causation, there would be no need for a transition to the FVT. However, other public interest concerns, such as gradualism and rate understandability and acceptance, preclude any desire to immediately move to such rates.

Realistic transition paths need to be developed to improve upon, and account for, these conditions, adapting as necessary as technology evolves and customer acceptance for dynamic prices increases. Correcting these issues in rates eliminates the need for programmatic fixes for specific technologies or stakeholders. For instance, as the retail rate design options evolve toward a FVT and become more efficient, a separate NEM tariff, fixed cost recovery charges, or even NEM limits/caps would <u>not</u> be needed, as any customer reduction in consumption and/or net injections onto the distribution grid would be priced at their 'value' <u>by design</u>.

A number of additional steps can be taken to limit the impacts of transition on customers who might be disproportionately affected by the FVT, including bill impact protections or grandfathering existing NEM customers.

5.3 Transitional Bill Impact Analysis under the Full Value Tariff

As stated earlier in this study, the FVT modifies the existing tariff structure by introducing a network subscription charge and converting the flat or tiered energy charges to hourly-varying dynamic prices. This section provides a comparison of customer bills between the existing retail rates and our illustrative FVTs, which include dynamic pricing for Consolidated Edison and National Grid residential customers in a local high value T&D constrained zone. The illustrative bill impacts are calculated assuming no customer response to the FVT. These bills are therefore similar to the bills of customers in non-constrained zones. To help isolate the effect of the rate structure change, the FVT has been set to collect the same total class revenues as the 2012 utility rates, assuming no changes in customer usage. This type of analysis and comparison is crucial in developing transition pathways in order to provide bill protections in the interim to smooth the transition along the principle of 'gradualism' as expressed in the Track 2 White Paper.

Under the existing retail rates about 85% of class revenues are collected via energy charges. Under the FVT, roughly 45% is collected via energy charges. The vast majority of the difference is shifted to the network subscription charge, which again reflects a customer's maximum usage of the utility grid. By introducing a network subscription charge, the FVT avoids the problem of large bill impacts to smaller customers that would otherwise have occurred if those costs were collected via a fixed per month customer charge increases. The first table below shows a comparison of average monthly bills for residential customers of increasing size[56] under the historical 2012 retail rate and projected under the FVT for Consolidated Edison. Because the

[56] We examine different strata of residential customers based on the load research data that was available. For ConEd strata 1 = 146 kWh/month, strata 2 = 297 kWh/month, strata 3 = 432 kWh/month, strata 4 = 680 kWh/month, and strata 5 = 3,040 kWh/month. For National Grid strata 1 = 319 kWh/month, strata 2 = 541 kWh/month, strata 3 = 704 kWh/month, strata 4 = 1,211 kWh/month, and strata 5 = 1,715 kWh/month.

FVT is revenue neutral at the class level, the customer and network subscription charges have been reduced to avoid over collecting from customers on a forecast basis.

Table 13: Bill comparison between the proposed FVT (no societal adders or externality adjustment) between different size or 'strata' customers for Consolidated Edison residential customers.

Average Monthly Bills	Full Value Tariff				Actual Rates			Change in Bills	
	Customer Charges	Network Subscription	Dynamic Pricing	Total	Customer Charges	Energy Charges	Total	$	%
Strata 1: 146 kWh/month	$20.67	$14.07	$16.20	**$50.94**	$15.76	$30.20	**$45.96**	**$4.98**	**11%**
Strata 2: 297 kWh/month		$23.29	$32.51	**$76.47**		$62.32	**$78.08**	**($1.61)**	**-2%**
Strata 3: 432 kWh/month		$34.92	$49.52	**$105.11**		$91.73	**$107.49**	**($2.38)**	**-2%**
Strata 4: 680 kWh/month		$62.24	$93.32	**$176.23**		$147.51	**$163.27**	**$12.96**	**8%**
Strata 5: 3,040 kWh/month		$270.59	$271.16	**$562.42**		$645.00	**$660.76**	**($98.34)**	**-15%**

The table above shows a small increase for the smaller customers, and decrease for the larger customers. This increase for small customers is driven by the difference in the customer charge. The difference for large customers is driven by the FVT energy charges that are only collecting the market cost of energy and capacity and the marginal cost of sub-transmission and distribution capacity vs. collecting market, embedded, and some customer-related costs in the energy charges of existing rates.

The table below shows the same comparison, but with a FVT that includes a societal adder or externality adjustment of approximately ~3 cents per kWh. This increases the energy collection to 60% of class revenues, and we proportionally reduce the customer and network subscription charges to maintain class revenue neutrality.

Table 14: Bill comparison between the proposed FVT (with a societal adder) between different size or 'strata' customers for Consolidated Edison residential customers.

Average Monthly Bills	Full Value Tariff + Societal Adder				Actual Rates			Change in Bills	
	Customer Charges	Network Subscription	Dynamic Pricing	Total	Customer Charges	Energy Charges	Total	$	%
Strata 1: 146 kWh/month	$20.67	$8.19	$21.34	**$50.20**	$15.76	$30.20	**$45.96**	**$4.24**	**9%**
Strata 2: 297 kWh/month		$13.56	$42.95	**$77.18**		$62.32	**$78.08**	**($0.90)**	**-1%**
Strata 3: 432 kWh/month		$20.34	$64.80	**$105.81**		$91.73	**$107.49**	**($1.68)**	**-2%**
Strata 4: 680 kWh/month		$36.24	$117.29	**$174.20**		$147.51	**$163.27**	**$10.93**	**7%**
Strata 5: 3,040 kWh/month		$157.55	$378.89	**$557.11**		$645.00	**$660.76**	**($103.65)**	**-16%**

The increase in the energy charge collection dampens the realignment of bills between smaller and larger customers although based on our load research there is a minimal difference for the largest users and there can be non-intuitive results for customers of different sizes depending on their consumption patterns and the number of customers of difference sizes. For example, the consumption pattern may align more naturally with the higher priced dynamically priced hours and there might be more of these customers which could lead to bill increases and vice versa.

The tables below show similar bill comparisons for National Grid residential customers. As with Consolidated Edison, the FVT would result in only a relatively small realignment of costs between small and large customers compared to current rates while achieving the efficiency and technology gains highlighted in previous chapters of this study.

Table 15: Bill comparison between the proposed FVT (no societal adders or externality adjustment) between different size or 'strata' customers for National Grid residential customers.

Average Monthly Bills	Full Value Tariff				Actual Rates			Change in Bills	
	Customer Charges	Network Subscription	Dynamic Pricing	Total	Customer Charges	Energy Charges	Total	$	%
Strata 1: 319 kWh/month	$23.89	$9.61	$22.44	**$55.94**	$17.00	$31.29	**$48.29**	**$7.65**	**16%**
Strata 2: 541 kWh/month		$12.00	$34.71	**$70.60**		$53.52	**$70.52**	**$0.08**	**0%**
Strata 3: 704 kWh/month		$19.85	$46.07	**$89.81**		$70.00	**$87.00**	**$2.81**	**3%**
Strata 4: 1,211 kWh/month		$24.32	$73.44	**$121.65**		$119.75	**$136.75**	**($15.10)**	**-11%**
Strata 5: 1,715 kWh/month		$36.95	$112.65	**$173.49**		$171.74	**$188.74**	**($15.25)**	**-8%**

Table 16: Bill comparison between the proposed FVT (with a societal adder) between different size or 'strata' customers for National Grid residential customers. Note, the refund from the over collection on the dynamic pricing is greater than the network subscription charge, which is then used to zero out the network subscription charge and then offset some of the customer charges.

Average Monthly Bills	Full Value Tariff + Societal Adder				Actual Rates			Change in Bills	
	Customer Charges	Network Subscription	Dynamic Pricing	Total	Customer Charges	Energy Charges	Total	$	%
Strata 1: 319 kWh/month	$22.07	*$0.00*	$31.20	**$53.27**	$17.00	$31.29	**$48.29**	**$4.98**	**10%**
Strata 2: 541 kWh/month	$21.62	*$0.00*	$50.20	**$71.82**		$53.52	**$70.52**	**$1.30**	**2%**
Strata 3: 704 kWh/month	$20.12	*$0.00*	$64.01	**$84.13**		$70.00	**$87.00**	**($2.87)**	**-3%**
Strata 4: 1,211 kWh/month	$19.26	*$0.00*	$106.73	**$125.99**		$119.75	**$136.75**	**($10.76)**	**-8%**
Strata 5: 1,715 kWh/month	$16.86	*$0.00*	$175.86	**$192.72**		$171.74	**$188.74**	**$3.98**	**2%**

The tables above summarize the customer impacts with average monthly bills. The FVT, however, will also affect the monthly variation in customer bills. Generally, the increase in the customer charge and the introduction of the network subscription charge will result in bills that are more **consistent** for customers from month to month. The customer charge does not change by month, and the network subscription charge is applied to a customer's highest monthly energy usage in the current and prior 11 months, which both lead to more stable and predictable customer bills combined with the initial dynamic pricing bill credits.

5.4 Illustrative Implementation Pathways

This section of the chapter presents an illustrative step by step transition along both a gradual and rapid FVT implementation pathway, both of which begin by offering retail customers an opt-in ‘smart’ rate modeled after the FVT.

5.4.1 INITIAL TRANSITION STEPS ON BOTH PATHWAYS

We propose that the following transition steps be implemented regardless of whether REV is transitioning on a gradual or rapid pathway. These steps can be implemented in parallel or sequentially depending on the underlying enabling conditions and policy direction. Regardless, we believe that these initial transition steps are low risk choices because of their opt-in nature and limited scope. Further, these steps will greatly inform the pace and form of the next transition steps with the ultimate goal of full FVT implementation.

Table 17: Initial transition steps that can be immediately implemented along either a gradual or rapid pathway.

Initial Transition Steps	Description
Create a sophisticated 'Smart Home' and 'Smart Business' opt-in rate	This opt-in rate should be more economically efficient with regards to collecting the distribution utility network costs through a sized-based connection charge (i.e., a network subscription charge), along with allowing for more technology and market offerings to manage customer loads to achieve customer savings and maximize value to the grid. The Smart Home and Smart Business rates should be based on the FVT and include dynamic pricing consisting of RTP energy pricing (can be nodal or zonal) and dynamic pricing for system capacity and sub-transmission/distribution pricing. Dynamic pricing consists of RTP+ICAP for all customers, with sub-transmission/distribution capacity dynamic pricing layered on top in high value locations. The distribution utility can iterate in terms of what dynamic prices are necessary to achieve system efficiencies without unduly penalizing customers. Bill protection mechanisms can be employed. New AMI meters installed for opt-in customers and can be paid for by opt-in customers or socialized across all customers as a program participation incentive.
Constrained area opt-in peak time capacity rebate	Create a program to provide capacity rebates, similar to a CPP concept, in localized constrained or 'high value' areas notwithstanding free ridership and baseline determination issues. Programs can differ for residential vs. C&I customers vs. large aggregators. Residential bill protection mechanisms can be incorporated at first. New AMI meters installed for opt-in customers again either at the customer's cost or socialized in all rates as an incentive.
Distribution utility RFPs or solicitations for DERs to avoid/defer distribution CapEx or OpEx	Engage in more localized solicitations like ConEd's BQDM to enter into medium to longer term DER contracts depending on the CapEx avoided (1-3-year PPA for short-term deferral or 10-15 year PPA for long-term avoidance). Open only to aggregators and larger C&I customers to meet distribution utility performance criteria for deferral/avoidance value.

5.4.2 'GRADUAL' PATHWAY

The following details a gradual pathway toward FVT implementation along the following lines:

+ An investment in AMI-enabled meters is <u>not</u> required for the vast majority of ratepayers. The opt-in rate can be implemented quickly by building on existing opt-in programs and prior experience with utility procurement with minimal impacts to traditional customers and the underlying rate designs.
+ NEM can transition on a separate REV reform path/timeframe to a more value-based pricing mechanism and/or with the introduction of a network subscription charge as certain policy adoption goals/technology cost declines are achieved, as the underlying market is transformed, and/or as customer sophistication increases.
+ The vast majority of customers are unaffected and the gradual pathway serves as a low-risk implementation path that can accelerate to a more rapid pace if the underlying enabling conditions are met.

Table 18: Potential gradual pathway choices from the initial transition steps.

Gradual Pathway Steps	Description
Monitoring and potential refinement of the opt-in 'Smart Home' and 'Smart Business' rates	As the distribution utility and technology evolve, monitor the initial Smart Home and Smart Business opt-in rates to evaluate program participation and the market response to see if the rate should be revised or reformulated to encourage more positive outcomes.
NEM evolution by creating a network subscription charge	Depending on whether NY Sun goals are achieved a transition from NEM at 1:1 retail rate to a more dynamic and value-based mechanism can begin. First step is for DER prosumers to pay a network subscription charge or grid access fee to recoup any under collection of fixed costs to maintain the distribution utility network. This can be waived for either all customers or certain specific classes like residential during the transition depending on the state of the market and/or certain policy goals are met.

NEM evolution by creating export credit based compensation for net injections	Transition away from 1:1 retail credit DER compensation to an asymmetric rate where exports or net injections to grid are paid at value (i.e. monetized utility avoided costs), and customer generation that offset on-site consumption avoids the prevailing retail rate. Full NEM can potentially be kept as a transition for high value or locally constrained areas for certain classes like residential customers. AMI and generation meters can be installed for customer generators to determine hourly netting amounts, but are not necessarily required as modeled proxy factors can be used.
NEM evolution to value-based credits for customer generation	Transition to value-based compensation that pays for customer generation on a value-based credit (VBC) basis. This can either be a short-term signal, i.e. resets annually, or a longer-term fixed price based on vintage, e.g. 5-20 year price. If the VBC does not enable adoption targets to be met then a competitively bid REC or societal premium can be bid out (or estimated), fixed by vintage for 5-20 years as well. This can also vary by customer class and/or location depending on the state and maturity of the market and locational value. This can either be set by quantity to reach certain adoption goals or by incentive price/budget reserve pricing. New AMI meters and generation meters are installed.

Table 19: Potential gradual pathway longer-term end state.

Gradual Pathway Steps	Description
End State	Opt-in Smart Home and Smart Business rates modeled after the FVT with a size differentiated connection charge and dynamic pricing along with credit based compensation mechanisms like local DR/peak time rebate programs and locational VBCs for customer sited generation as an evolution of NEM (which can include a longer-term REC or investment signal). Specific solicitations are held for DERs to avoid/defer short-term/long-term distribution CapEx. Distribution utility model is based more on performance based incentives and certain market based earning price streams along with size- based recovery of network costs.

5.4.3 'RAPID' PATHWAY

The following details a rapid pathway toward FVT implementation along the following lines:

+ No separate transition path for NEM as the path begins with phasing in a FVT that is mandatory or default for new NEM eligible customers and is opt-in for other customers, i.e. a 'Smart Home' or 'Smart Business' rate .
+ An investment in AMI-enabled meters is not required for the vast majority of ratepayers at first, but movement begins toward full AMI deployment for all customers is necessary over time. Eventually, all customers default onto the FVT, i.e. a Smart Home or Smart Business rate.
+ The enabling conditions are met to warrant a rapid transition to FVT implementation with policy goals being achieved and the market transformed.

Table 20: Potential rapid pathway choices from the initial transition steps.

Rapid Pathway Steps	Description
Default TOU or RTP pricing with opt-out provision	Change underlying default residential and small commercial rate design to a more TOU based pricing mechanism. Larger customers should be on RTP with locational dynamic pricing modeled on the FVT if not already. Mass deployment of AMI for all default customers. Bill protection mechanisms may be needed at first.
Default size differentiated connection charge and RTP dynamic pricing	Change underlying retail rate designs to resemble the FVT, i.e. the Smart Home or Smart Business opt-in rates with size differentiated connection charge, and RTP dynamic pricing (energy could be nodal or zonal depending on market evolution) after distribution utility evolution and lessons learned from the opt-in pilot program(s). Bill protection mechanisms may be needed at first.

Table 21: Potential rapid pathway longer-term end state

Rapid Pathway Steps	Description
End State	FVT implementation with default size differentiated customer connection charge with localized dynamic pricing to compensate both load shifting technologies and customer generation for full value (although a longer-term REC price may be in place to provide investment signal and any 'missing money' for longer lived DER assets). Specific solicitations are held for DERs to avoid/defer short-term/long-term distribution CapEx or OpEx. The distribution utility model consists of revenues more aligned with costs with various network users paying for value received or compensated for value provided leading to a higher value and more transactive network.

6 Conclusions

As articulated throughout the REV Proceeding, transforming the retail rate structure to reflect an efficient economic signal would achieve a number of objectives in the public interest. The proposed FVT provides an achievable path to this goal. If successful it can:

+ Save ratepayers money by avoiding **future** expenditures in the distribution network and encouraging adoption of appropriate DER in areas of the network with high avoidable costs.
+ Increase economic activity by making low cost electricity available when it is actually low cost.
+ Provide an economic foundation that can guide a whole range of investment and operational decisions without explicitly needing to address these problems in a programmatic framework. For example, 'smart charging' electric vehicles is an emerging topic that a FVT can support without any changes.
+ Create a vibrant market for technology by providing a compensation mechanism based on value and removing programmatic, regulatory based rules and baselines for participation.
+ Provide a specific lever for the State to efficiently address climate change, local criteria emissions, and other externalities.

As with any rate design, the path towards transition is critical for implementation. The FVT proposal is designed to accentuate positive and limit negative consequences for the public and key stakeholders. These stakeholders include New York ratepayers foremost, but also distribution utilities, environmental and local interests, technology innovators, and ESCOs.

Key FAQs:

Q: What has changed with regards to implementing mass market real time pricing (RTP)?

A: Technology has made RTP possible. This includes control technology for appliances and energy management systems, data and information on distribution system operations, and lower cost and more capable AMI systems.

Q: Why transition toward default rates that reflect area- and time-specific costs, rather than optional credits?

A: Optional credits either create a large risk of free riders, or require defining a customer baseline which limits participation and adds complexity. For programs that operate a few times per year a simple baseline is implementable, but for load shifting every day, establishing 'normal' operations in a baseline is problematic. In addition, broad participation in a default rate allows many small load changes to add up to meaningful impacts.

Q: Why is it important to collect embedded costs with network subscription charges?

A: Mispriced components lead to inefficient investment and operation decisions by customers. Without a size-based access charge to recover residual embedded costs, higher volumetric rates are required which charge customers more than the marginal costs for energy consumption. Access charges reduce uneconomic bypass and lessens social welfare loss.

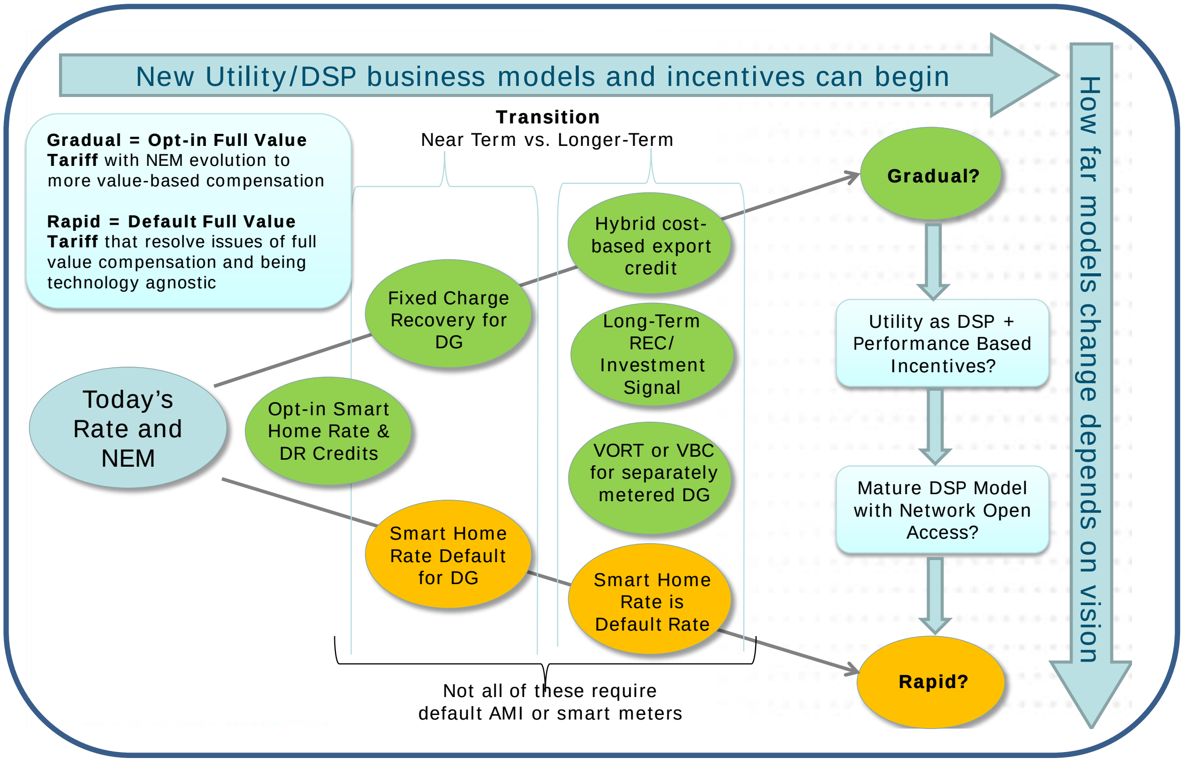
An access charge reduces the risks of recovering residual utility embedded costs, provides greater revenue stability on existing assets for utilities, limits uneconomic bypass, and should allow utilities to achieve lower financing costs of the network on behalf of all ratepayers. This strategy could enable the evolution of different utility business models, such as separating the utility into an independent distribution system operator that plans and operates the grid and an asset company that uses asset-backed financing and a fixed revenue stream based on the network subscription charge to finance and maintain the network at a lower cost.

Q: Does the proposed FVT eliminate the incentive for investment in energy efficiency for non-demand, mass-market customers?

A: No. The varying dynamic price will provide an appropriate economic signal for changes in consumption behavior and energy efficiency. The energy efficiency that occurs during peak times will be valued more than they are with existing rates, and off-peak times less.

Secondarily, the network subscription charge is based on network usage and depending on how network usage is defined energy efficiency may reduce an individual customer's network usage and those associated costs over time.

Figure 37: There are several different transition steps and implementation pathways that can be pursued, but the 'end states' need to be defined in order to optimize the transition and develop strategic implementation pathways. Each 'end state' can also be a transition step as REV is implemented. As the end states are reached and technology evolves new and innovative business models can emerge with the potential to lower costs and increase system efficiency.



7 Appendix

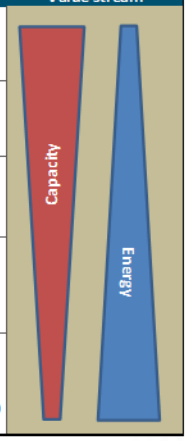
7.1 Key Background Concepts

There are two main types of DERs:

1. DERs that generate electricity (i.e. prosumers) like distributed solar PV.
2. DERs that provide demand side management (DSM) or demand response (DR) by shifting load (i.e. active customers). Examples include 'smart' or controllable appliances/HVACs as well as DERs that increase energy efficiency such as LEDs.
    - Storage and electric vehicles can be either type of DER depending on their use.
    - Customers can also provide DSM by changing their behavior with electric end uses and/or reducing their total use of electricity in order to realize savings.
    - Compensation for DER generation and DSM/DR can be either ***incentive*** based or ***price*** based.

Figure 38: DER technologies offer a diverse range of benefits (both energy and various types of capacity) that can all be potentially valued and compensated.

Category	Primary purpose	Timeframe	Value stream
Emergency demand response	Improve reliability	Seldom, during contingency	
Demand response	Reduce powerplant construction	<100 hours per year	
Permanent load shifting	Improve load factor	Daily, all year, or by season	
Renewable distributed generation	Reduce fuel consumption and emissions, avoid new powerplant construction	Year round with seasonal, diurnal trends	
Energy efficiency	Reduce fuel consumption and emissions, avoid new powerplant construction	During device operation (e.g., seasonal, or daily)	



Competing goals

DER price signals or compensation mechanisms should be 'dynamic' to provide the appropriate signals to reduce load and/or increase generation during key times

Signals should also be 'stable' to provide investment signals for DER technologies

Figure 39: There are two main categories of compensation for customers who adopt DERs that generate electricity onsite. There may be additional rate/tariff charges that can be applied, such as a standby charge ($/kW nameplate) or a grid/network use charge on exports or on all generation ($/kW-month or $kWh).

NEM (Compensation at Retail Rates)

- **Participants and non-participants in the same class**
  - Compensation levels driven by rate design
- **Participants and non-participants in separate classes**
  - Compensation levels driven by cost allocation
  - Large administrative burden

VORT, FiT, VBC, or Adder (Compensation Independent of Rates)

- **Level and design could be based on:**
  - Net utility system value of DER, i.e. "value" based either as a buy all/sell all or bill credit "payment"
  - Net societal value of DER or "missing money"
  - Renewable DG capital or financing costs, i.e. "cost based"

These compensation categories may or may not have different tax implications

Figure 40: There are three types of generation associated with DER generation by 'prosumers', all of which can be potentially compensated at a different rate. Currently all these types of generation are all compensated at the customer's prevailing retail rate under net energy metering (NEM).

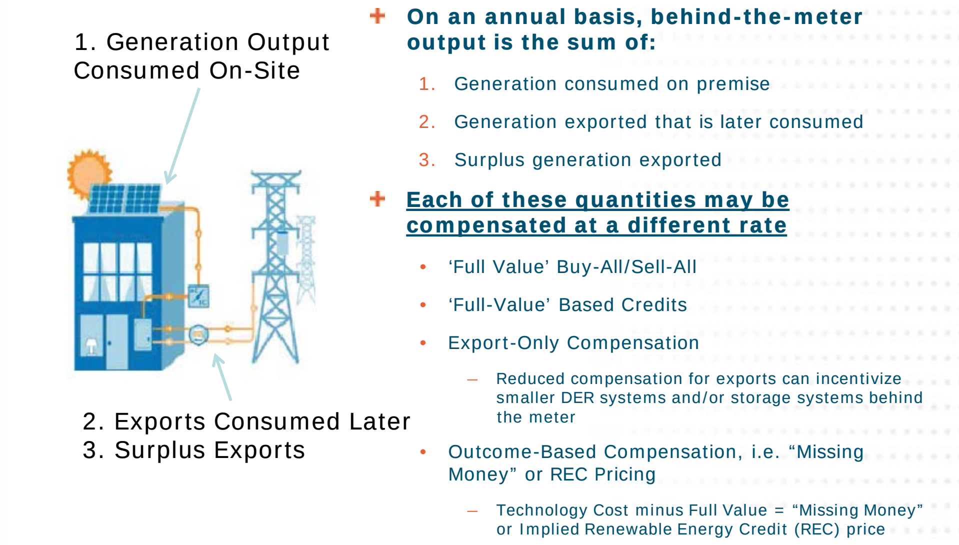
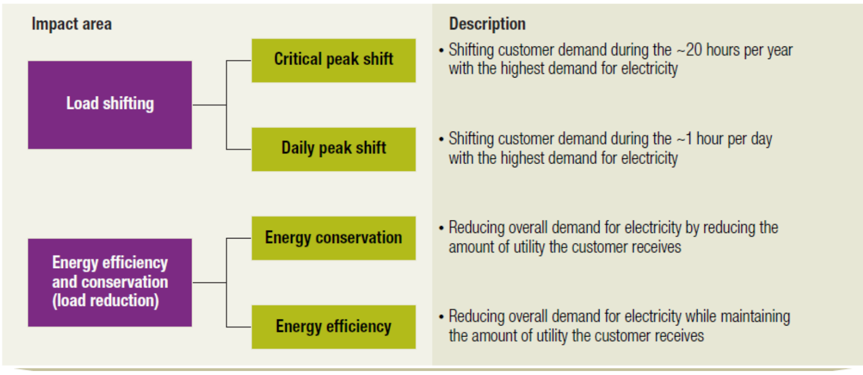


Figure 41: There are a number of different DSM/DR activities and levers involving load shifting and energy efficiency/conservation.[57]



57 https://www.mckinsey.com/~/media/mckinsey/dotcom/client_service/EPNG/PDFs/McK%20on%20smart%20grids/MoSG_DSM_VF.ashx

Figure 42: DSM/DR can be compensated on either a price or an incentive (i.e. rebate with a baseline calculation) basis that can vary by time and duration[58].

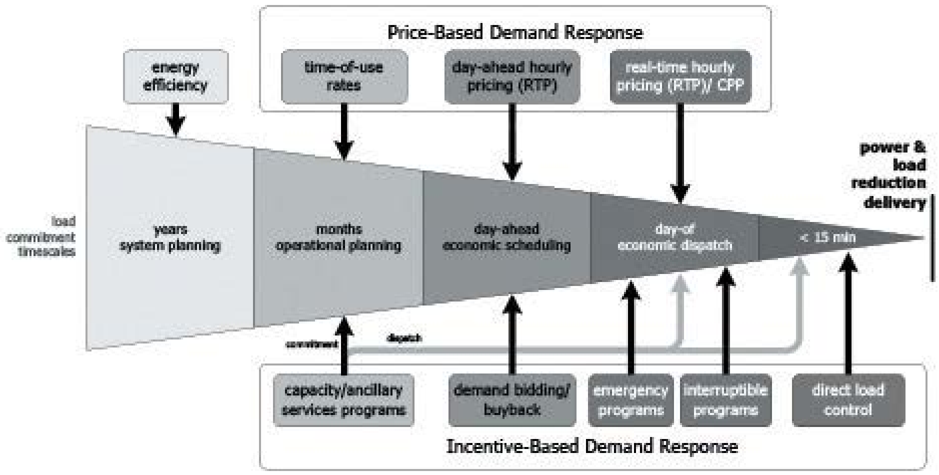
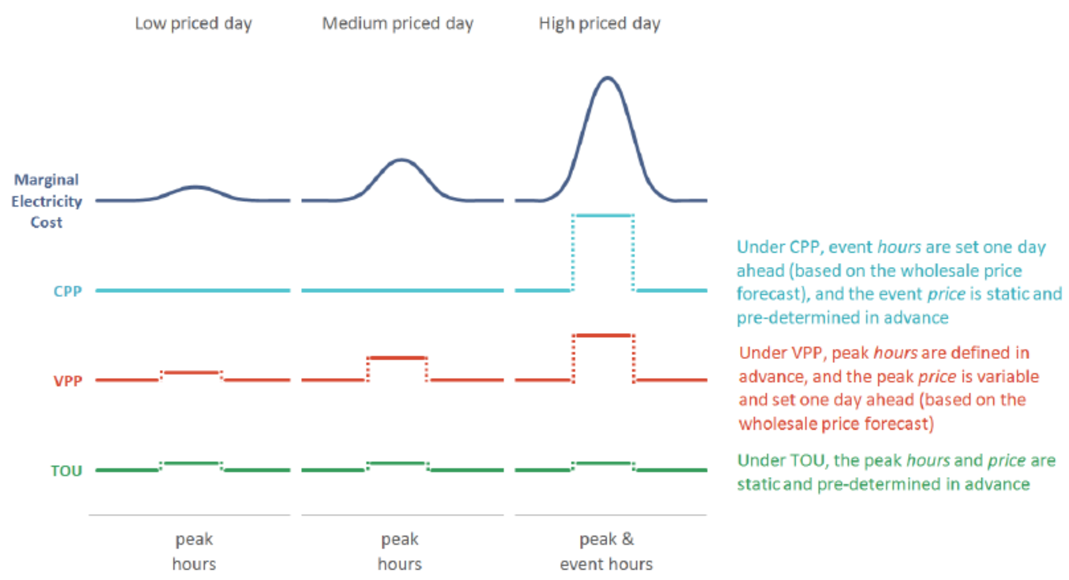


Figure 43: There are a number of tools and options that can be used to manage demand.[59]

DSM lever	Design options	Description
Rates	• Flat rate • Critical peak pricing (CPP) • Time of use (TOU) • Real-time pricing (RTP) • Interverted block pricing	• Same rate at all times • Extremely high rates during critical peaks • Variable pricing for prescheduled blocks of time • Variable pricing at all times, informed close to instantaneously • Increase rate for higher use customers
Incentives	• No incentives • Provide rebates on bill • Provide cash compensation	• Base case • Debit bill based on degree of behavior change • Provide separate check to encourage behavior change
Information	• None • Event notification • Real time usage • Historical usage • Comparative usage • Device-specific usage • Billing usage	• Monthly paper bills and consumption information • Notification of DR events under way • Consumption at a given moment (e.g., kW, light bulb equivalents) • Consumption compared to previous period of time • Consumption compared against last month's or peers' • Individual device usage in real time; can be paired with above • Real-time billing information
Controls	• None • Programmable communicating thermostats (PCTs) • Smart appliances/plugs • Home energy controller • PHEV smart chargers • DG/S control devices	• No automation of devices to reduce energy consumption • Automated AC control • Automated appliance on/off • Centralized control & automation of major home appliances • Optimized charging of PHEVs • Optimized usage, storage, and later discharging of energy
Education	• No education • Educate by segment • Educate by channel • Educate by positioning	• Base case • Vary by income, consumption behavior, attitudes • Use various means: e-mail, bill inserts, newspaper, etc. • Emphasize different HAN benefits (reduced energy costs and carbon emissions, increased competition with neighbors, etc.)
Customer Insight and verification	• None • Verification of benefits capture	• Base case • Verify DSM (EE, EC, and DR) and economic utility captured by customers

[58] http://www.ferc.gov/market-oversight/guide/energy-primer.pdf
[59] https://www.mckinsey.com/~/media/mckinsey/dotcom/client_service/EPNG/PDFs/McK%20on%20smart%20grids/MoSG_DSM_VF.ashx

Figure 44: Illustration of several rate designs that send more economically efficient time-varying dynamic prices. These prices can be used to manage demand by allowing customers the option to be exposed to the savings possible from time variant prices. More efficient prices should lead to lower-cost and higher-valued allocation of economic resources.[60]



[60] https://www.smartgrid.gov/files/CBS_interim_program_impact_report_FINAL.pdf

Figure 45: Peak time rebates (PTR) or credits (PTC) are an incentive based design that provides rebates/credits during certain peak or critical periods for reducing demand from a calculated baseline.[61]

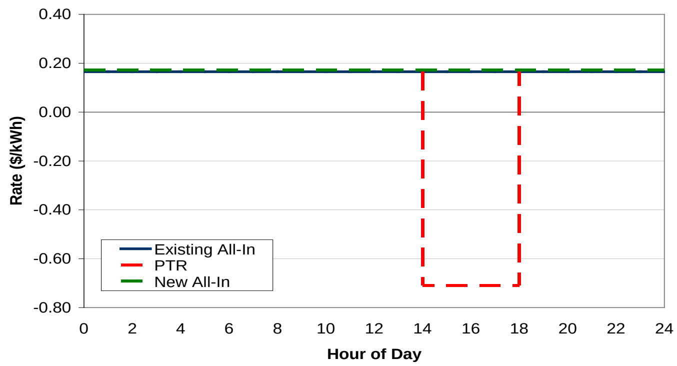
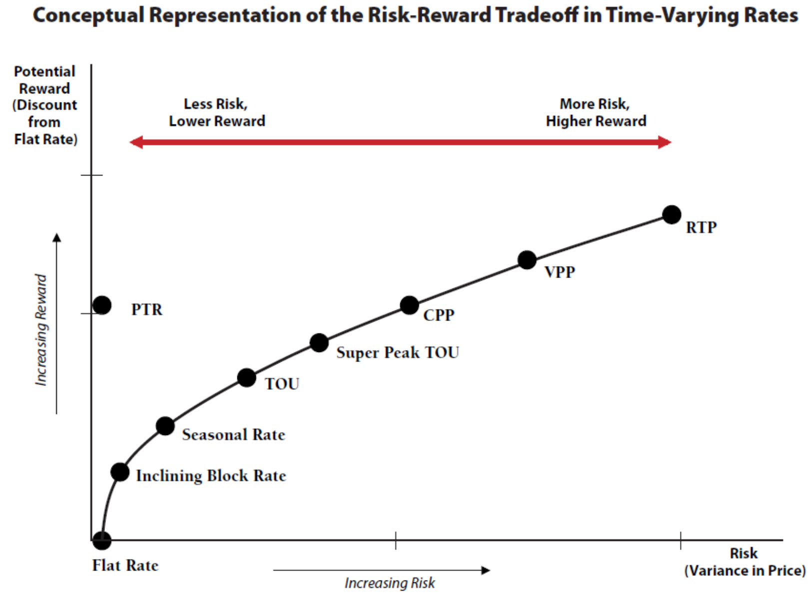


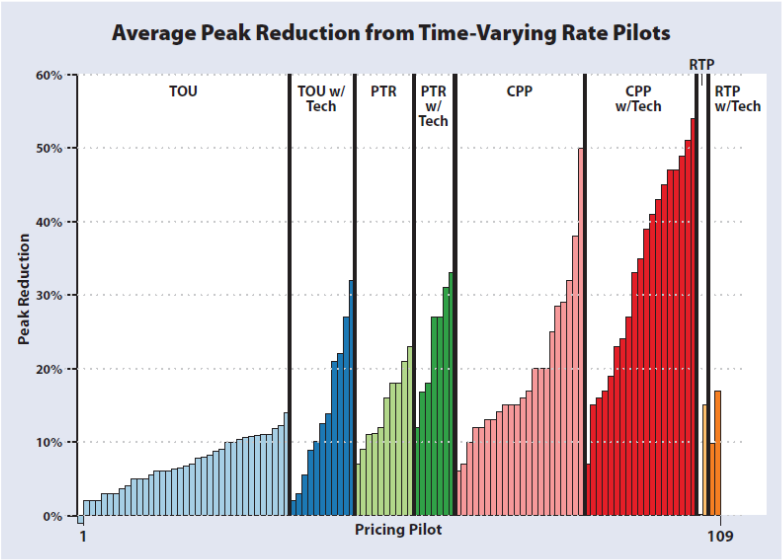
Figure 46: Various rate design choices have different outcomes in terms of risk and reward from the customer perspective.[62]



[61] The behavioral science theory of loss aversion states that when people are presented with choices that involve either avoiding a loss or acquiring a gain, the strong preference is almost always to avoid the loss rather than to acquire the gain. When applied to electricity time-based rates, customers are expected to be more likely to enroll in and remain on critical peak rebates (CPR) than Critical Peak Pricing. The risk from non-performance during critical events under CPP is greater than under CPR, and this could be a motivating factor that decreases enrollment and retention.
See: https://www.smartgrid.gov/files/CBS_interim_program_impact_report_FINAL.pdf

[62] . http://www.raponline.org/document/download/id/5131

Figure 47: Pilot programs have explored numerous types of time variant rates, which have realized varying levels of efficient peak load reduction. These pilots have included both opt-in and default opt-out versions, as well as with and without enabling technology.[63]



7.2 Fundamentals of Retail Rate Design

7.2.1 EMBEDDED COSTS VS. MARGINAL COSTS

There are two equally important types of costs that need to be reflected and collected through rates: 1) embedded costs and, 2) marginal costs. The embedded costs are fixed and are what was prudently incurred to build and maintain the network. The marginal costs are forward-looking avoided costs. The latter should form the basis of any 'full value' dynamic tariff or rate. The former needs to be collected from all customers through their bills in a fair and equitable manner, because all customers rely on the network unless totally disconnected. We present several methods and options that can potentially signal and collect these costs with various degrees of efficiency.

63 . http://www.raponline.org/document/download/id/5131

7.2.2 RETAIL RATE MECHANISMS

There are a number of retail rate mechanisms that can be used to both signal and collect marginal and embedded costs, respectively. These options vary by efficiency and efficacy and there are a number of pros and cons associated with each.

Figure 48: There are a number of different retail rate design options and mechanisms to collect and signal each type of cost (embedded and marginal) to customers. These rate design options allow customers to be exposed to the underlying fundamental cost signals and potential savings possibilities to varying degrees.

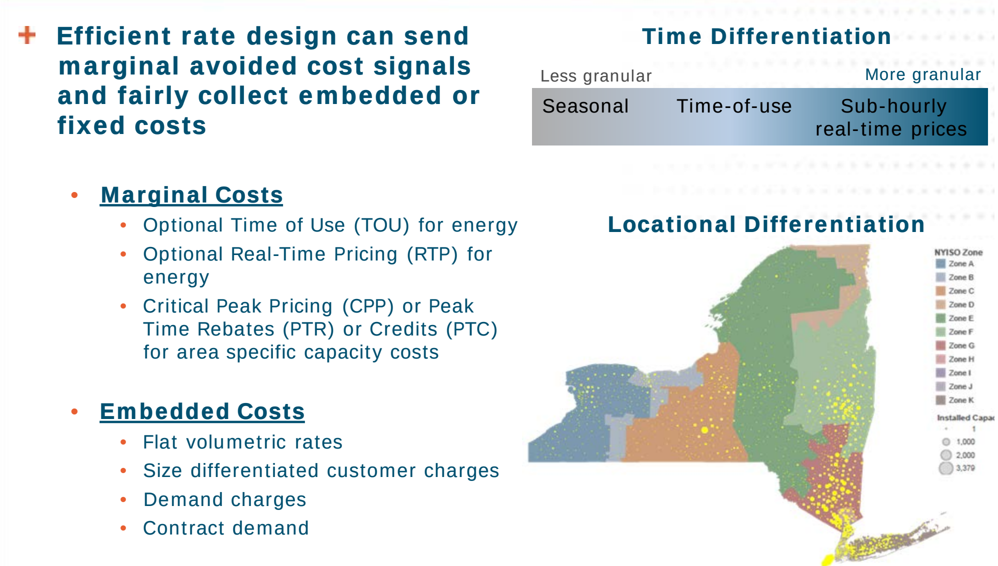
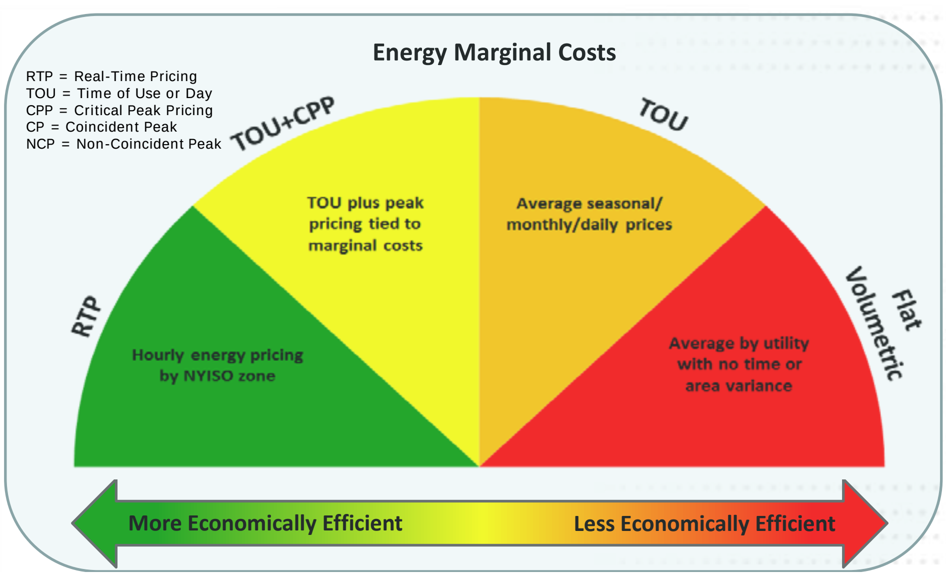
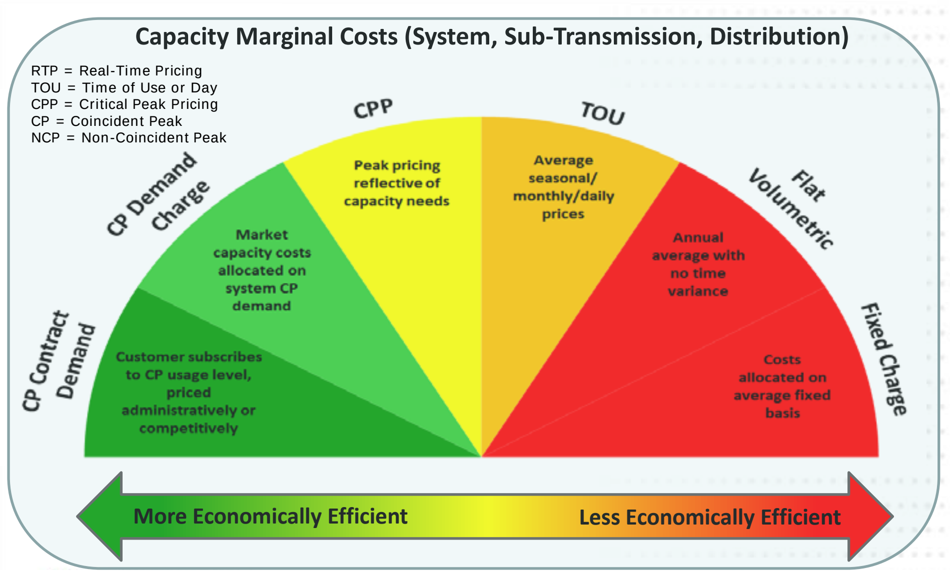
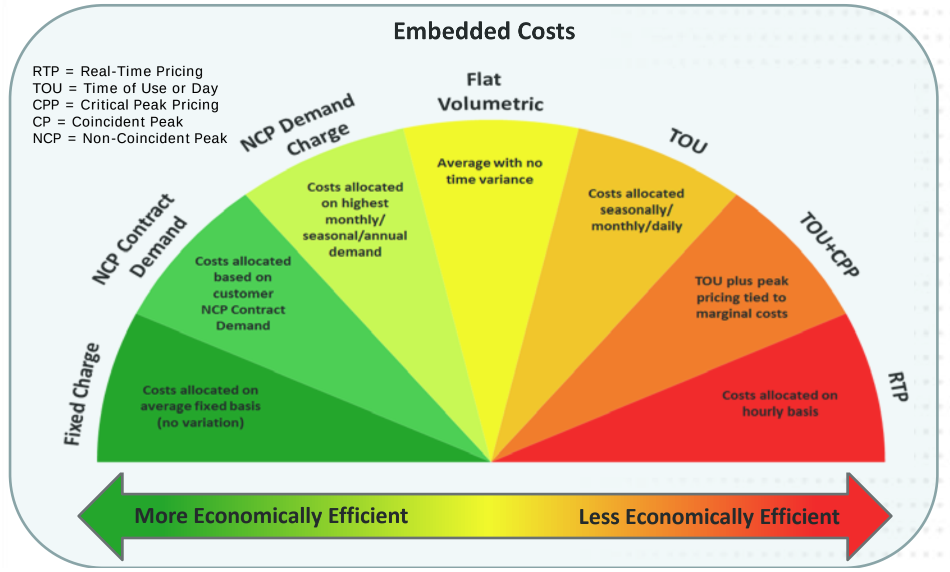


Figure 49: There is a spectrum of retail rate and tariff design features to collect each cost component, and economically efficient rates have other trade-offs such as a loss of the conservation signal. Also, each type of cost component can have a different spectrum. How far rate designs and tariff options should approach 'efficient' forms is a complex issue that affects many stakeholders and customers in different ways.







7.2.3 TRADITIONAL PRINCIPLES OF RATE DESIGN

Bonbright rate design principles[64].

- **Effectiveness**
  - Recover allowed capital and operating costs and a fair return
- **Fairness**

[64] http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf

- Fairly apportion the cost of service among different customers (rates reflect cost causation)
- Avoid undue discrimination

+ **Efficiency**
  - Promote the efficient use of energy (and competing products and services)
  - Support economic efficiency – set prices to reflect marginal costs
+ S**tability**
  - Ensure revenues (and cash flow) are stable from year to year
  - Minimize unexpected rate changes that may be adverse to existing customers
+ **Simplicity, understandability, public acceptability, and feasibility of application**

7.3 Fundamental Economic Cost Causation Rate

In order to develop a practically implementable FVT, we begin by using utility-filed embedded cost of service (ECOS) studies[65] and historic market data to calculate the revenues that would be fairly collected for each utility function for a range of customers. This is the amount that would be collected in a fundamental economic cost causation rate, i.e. functional utility costs assigned to the customer causation classifications. We perform this analysis for an upstate utility (National Grid) and a downstate utility (Consolidated Edison), and for residential customers of different sizes or strata to develop a range of perspectives. While we do not specifically develop a FVT for non-residential customers in this study, the same principles would be applied.

We build up the fundamental economic cost causation rate in three parts, parallel to the 'three part' rate structure described in the Track 2 White paper.

The three parts include:

[65] See http://www.coned.com/documents/2013-rate-filings/Electric/Exhibits/156-EXHIBIT___(DAC-2).pdf and https://www.nationalgridus.com/niagaramohawk/non_html/ratecase/Book20.pdf

(1) **Customer charge** ($/customer) = embedded costs and expenses associated with serving the customer such as the meter, meter servicing and customer billing.

(2) **Demand charge** ($/kW of coincident and non-coincident peak loads)[66] = embedded costs based on a customer's use of the existing distribution, sub-transmission, transmission, any remaining utility-owned generation assets on the grid, and regulatory balancing accounts, adders, and true-ups.

(3) **Marginal costs** ($/kWh)[67] = forward-looking marginal or avoidable costs of serving customer load including avoidable zonal hourly energy costs and losses along with avoidable delivery capacity and generation capacity costs during peak periods, and any avoidable merchant function charges allocated to peak hours.

Table 1 and Table 2 provide the ideal charge ($/customer, $/CP[68] kW, $/NCP[69] kW, $/kWh) and the ideal cost collection (average $/month per typical customer) for the components identified in part 1 and part 2 of the fundamental cost causation rate for Consolidated Edison and National Grid. These calculations are based on two assumptions: (1) the cost-causation-based allocation of embedded costs for the year that are then divided by 12 to show an average month (we use average month to be comparable to monthly bills), and (2) the load research data available by customer size to determine the load impacts[70].

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[66] The remaining residual network related costs would be collected based on a customer's usage of the network using cost causation principles. Network or network subscription is defined by a customer's share of the peak demands on the various network assets. In theory, a fundamental economic rate design would charge customers for their share of peak demands on each piece of network equipment (transmission substation, sub-transmission circuits, distribution transformers, distribution feeders, secondary lines, low voltage transformers, tap lines, etc.)

[67] Energy prices would be the marginal cost of energy (the locational-based marginal prices) plus losses, and could include the <u>avoidable</u> generation, transmission, and distribution marginal capital and operating costs allocated to the peak demand hour(s) on the respective systems that are driving the need for these expenditures. Alternatively, the marginal capacity costs could be priced as demand charges coincident with the timing of the peak hour(s) on the various distribution, sub-transmission, and bulk electrical systems. The marginal cost prices could also include energy price adder(s) for externalities or non-monetized societal costs. The focus of the marginal cost prices in the fundamental economic rate would be to provide customers with clear price signals that allow the customers to make consumption decisions based on actual marginal cost impacts.

[68] CP= coincident peak, which equals the customer's peak load that occur at the same time or is coincident with the system peak.

[69] NCP= non-coincident peak, which equals the customer's peak load which can occur in non-system peak hours.

[70] We examine different strata of residential customers. For ConEd strata 1 = 146 kWh/month, strata 2 = 297 kWh/month, strata 3 = 432 kWh/month, strata 4 = 680 kWh/month, and strata 5 = 3,040 kWh/month. For National Grid strata 1 = 319 kWh/month, strata 2 = 541 kWh/month, strata 3 = 704 kWh/month, strata 4 = 1211 kWh/month, and strata 5 = 1715 kWh/month.

Table 22: Allocation of embedded costs by component – Parts 1 and 2 – Consolidated Edison

Allocation of Embedded Costs based on ECOS Study	Part 1				Part 2			Total
	Customer Related Charges (Embedded Costs)				Demand Related Charges (Embedded Costs)			
	Customer Meters	Customer Revenue Cycle	Distribution	Subtotal	Sub-Transmission	Distribution	Subtotal	
Cost Causation Metric	**# Customers**	**# Customers**	**# Customers**		**1CP kW**	**NCP kW**		
Per unit Charge	**$4.62**	**$3.24**	**$14.37**	**$22.22**	**$2.80**	**$11.49**		
Average Monthly Charge Strata 1	$4.62	$3.24	$14.37	**$22.22**	$2.47	$10.12	**$12.60**	**$34.82**
Average Monthly Charge Strata 2					$5.92	$24.23	**$30.15**	**$52.37**
Average Monthly Charge Strata 3					$7.94	$32.50	**$40.44**	**$62.66**
Average Monthly Charge Strata 4					$8.85	$36.27	**$45.12**	**$67.34**
Average Monthly Charge Strata 5					$37.81	$154.87	**$192.68**	**$214.90**

Table 23: Allocation of embedded cost by component – Parts 1 and 2 – National Grid

Allocation of Embedded Costs based on ECOS Study	Part 1			Part 2			Total
	Customer Related Charges (Embedded Costs)			Demand Related Charges (Embedded Costs)			
	Customer Functions	Distribution	Subtotal	Sub-Transmission	Distribution	Subtotal	
Cost Causation Metric	**# Customers**	**# Customers**		**1CP kW**	**NCP kW**		
Per unit Charge	**$7.97**	**$17.89**	**$25.86**	**$1.98**	**$3.85**		
Average Monthly Charge Strata 1	$7.97	$17.89	**$25.86**	$8.38	$16.32	**$24.70**	**$50.56**
Average Monthly Charge Strata 2				$15.49	$30.17	**$45.66**	**$71.52**
Average Monthly Charge Strata 3				$13.13	$25.58	**$38.71**	**$64.57**
Average Monthly Charge Strata 4				$5.59	$10.89	**$16.48**	**$42.34**
Average Monthly Charge Strata 5				$15.15	$29.51	**$44.66**	**$70.52**

Table 3 and Table 4, below, provide the avoidable costs in the fundamental cost causation rate for the part 3 rate equal to the marginal cost of energy consumption for Consolidated Edison and National Grid. In addition to the monetized costs, we explicitly consider the 'societal marginal costs' that are not currently monetized in today's market. These are approximated using assumptions of a social price of CO_2 and health impact costs from criteria pollutant emissions. We recognize there may be other non-monetized societal factors that may be included to provide a societally optimal consumption decision. In addition, we include the marginal costs in constrained distribution and transmission areas that are equal to the forward-looking marginal capacity costs in that constrained area. In the fundamental cost causation rate these would vary by distribution and sub-zonal transmission and equal the forward-looking costs of providing additional capacity in each area. Lastly, we also show the various public purpose charges and other rate adders that are currently levied in rates on a volumetric basis.

Table 24: Marginal cost and externality build-up with breakdown of retail rate adders – Consolidated Edison

Marginal Cost Components	Marginal Cost	# Annual Allocation Hours	Max ($/kWh)	Average ($/kWh)
Zonal LMBP (Dynamic Pricing)	Varies by Hour	All	$1.25	$0.061
Merchant Function Charge[71]	Varies by Month	All	$0.0066	$0.0057
ICAP (Dynamic Pricing)	$90.00/kW-yr	Top 100 NYCA	$3.06	$0.900
Sub-Transmission (Dynamic Pricing)	$43.26/kW-yr	Top 100 Zone J	$1.43	$0.433
Distribution (Dynamic Pricing)	$77.96/kW-yr	N>2 = 436 Hours in example	$0.69	$0.171

Externalities	Marginal Cost	Marginal Emission Factors	Average ($/kWh)
CO_2 (EPA Social Cost of Carbon)	$40/Ton	0.538 tons/MWh	$0.022
SO_2 (EPA)	$56,500/ton	0.00029 tons/MWh	$0.016
Nox (EPA)	$8,600/ton	0.0003 tons/MWh	$0.002
		TOTAL	**$0.040**

Rate Adders	Average ($/kWh)
SBC[72]	$0.0030
RPS[73]	$0.0022
MAC[74]	$0.0089
TOTAL	**0.0141**

Table 25: Marginal cost and externality build-up with breakdown of retail rate adders – National Grid

Marginal Cost Components	Marginal Cost	# Annual Allocation Hours	Max ($/kWh)	Average ($/kWh)
Zonal LMBP (Dynamic Pricing)	Varies by Hour	All	$1.20	$0.038
Merchant Function Charge[75]	$0.00093 / kWh	All	$0.00093	$0.00093
ICAP (Dynamic Pricing)	$8.10/kW-yr	Top 100 NYCA	$0.276	$0.081
Sub-Transmission (Dynamic Pricing)	$22.62/kW-yr	Top 100 Zone J	$0.745	$0.226
Distribution (Dynamic Pricing)	$67.66/kW-yr	N>2 = 72 Hours in example	$3.337	$0.940

[71] http://www.coned.com/rates/elec_MFC_PSC10.asp
[72] http://www.coned.com/rates/elec-historical_sbc.asp
[73] http://www.coned.com/rates/elec_RPS_PSC10.asp
[74] http://www.coned.com/rates/elec_MACstatement_PSC10.asp
[75] http://www.nationalgridus.com/niagaramohawk/includes/non_html/elec_psc220_II.pdf

Externalities	Marginal Cost	Marginal Emission Factors	Average ($/kWh)
CO_2 (EPA Social Cost of Carbon)	$40/Ton	0.538 tons/MWh	$0.022
SO_2 (EPA)	$56,500/ton	0.00029 tons/MWh	$0.016
Nox (EPA)	$8,600/ton	0.0003 tons/MWh	$0.002
		TOTAL	**$0.040**

Rate Adders[76]	Average ($/kWh)
SBC	$0.00058
EE	$0.00400
RPS	$0.00306
ESRM / LTC	$0.00362
TOTAL	**$0.01126**

Putting the three parts together yields the following fundamental cost causation rates for illustrative Consolidated Edison and National Grid residential strata. The combination is not a simple sum since the marginal cost components include non-cost items such as externalities and future avoidable capacity costs. In developing the combined fundamental rate, we adhere to the principle that the marginal cost signal (Part 3) should stay equal to the estimated marginal costs, and that any additional revenue that is collected be used to offset customer and embedded costs (Parts 1 and 2) in a proportional or pro rata manner. Since the marginal capacity costs vary by area, the level of this 'credit' would similarly vary by area.

Table 5 shows the revenue that would be collected (average $/month) under the combined fundamental rate (marginal costs + residual embedded costs), in unconstrained and constrained areas for Consolidated Edison without the addition of externalities. Table 6 shows the same information if externalities are included. Table 7 and Table 8 show the same information for National Grid.

[76] https://www.nationalgridus.com/niagaramohawk/business/rates/5_elec_sc2.asp

Table 26: Ideal rate build-up (no externality adjustment) – Consolidated Edison

Fundamental Economic Rate (Embedded Cost + Marginal Dynamic Pricing)	Part 1			Part 2				Part 3						
	Customer Charges (Embedded Costs)			Demand Charges (Embedded Costs)				Energy Charges (Marginal Costs)						
	Customer Meters	Customer Revenue Cycle	Distribution	ICAP	Sub-Transmission	Distribution	MAC Collection	Rate Adders	LBMP Avg (Max)	MFC	ICAP Avg (Max)	Sub-Transmission Avg (Max)	Distribution Avg (Max)	Externalities
Cost Causation Metric	# Customers	# Customers	# Customers	NCP kW	1CP kW	NCP kW	NCP kW	kWh	kWh	kWh	kWh	kWh	kWh	kWh
Rate/Charge	$4.62	$3.24	$14.37	$2.05	$2.80	$11.49	$1.43	$0.0052	$0.0614 ($1.2496)	$0.0057 ($0.0066)	$0.900 ($3.063)	$0.171 ($0.685)	$0.433 ($1.426)	$0.00

Table 27: Ideal rate build-up (with externality adjustment) – Consolidated Edison

Fundamental Economic Rate (Embedded Cost + Marginal Dynamic Pricing)	Part 1			Part 2					Part 3						
	Customer Charges (Embedded Costs)			Demand Charges (Embedded Costs)					Energy Charges (Marginal Costs)						
	Customer Meters	Customer Revenue Cycle	Distribution	ICAP	Sub-Transmission	Distribution	MAC Collection	Embedded Cost Refund	Rate Adders	LBMP Avg (Max)	MFC Avg (Max)	ICAP Avg (Max)	Sub-Transmission Avg (Max)	Distribution Avg (Max)	Externalities
Cost Causation Metric	# Customers	# Customers	# Customers	NCP kW	1CP kW	NCP kW	NCP kW	NCP kW	kWh	kWh	kWh	kWh	kWh	kWh	kWh
Rate/Charge	$4.62	$3.24	$14.37	$2.05	$1.45	$9.45	$1.43	($5.59)	$0.0052	$0.0614 ($1.2496)	$0.0057 ($0.0066)	$0.900 ($3.063)	$0.171 ($0.685)	$0.433 ($1.426)	$0.0403

Table 28: Ideal rate build-up (with externality adjustment) – National Grid

Fundamental Economic Rate (Embedded Cost + Marginal Dynamic Pricing)	Part 1		Part 2			Part 3						
	Customer Charges (Embedded Costs)		Demand Charges (Embedded Costs)			Energy Charges (Marginal Costs)						
	Customer Services	Distribution	ICAP	Sub-Transmission	Distribution	Rate Adders	LBMP Avg (Max)	MFC Avg (Max)	ICAP Avg (Max)	Sub-Transmission Avg (Max)	Distribution Avg (Max)	Externalities
Cost Causation Metric	# Customers	# Customers	NCP kW	1CP kW	NCP kW	kWh	kWh	kWh	kWh	kWh	kWh	kWh
Rate/Charge	$7.97	$17.89	$0.17	$1.98	$3.85	$0.0113	$0.036 ($1.1952)	$0.00073	$0.081 ($0.2757)	$0.2262 ($0.745)	$0.9397 ($3.337)	$0.00

Table 29: Ideal rate build-up (with externality adjustment) – National Grid

Fundamental Economic Rate (Embedded Cost + Marginal Dynamic Pricing)	Part 1		Part 2				Part 3						
	Customer Charges (Embedded Costs)		Demand Charges (Embedded Costs)				Energy Charges (Marginal Costs)						
	Customer Services	Distribution	ICAP	Sub-Transmission	Distribution	Embedded Cost Refund	Rate Adders	LBMP Avg (Max)	MFC Avg (Max)	ICAP Avg (Max)	Sub-Transmission Avg (Max)	Distribution Avg (Max)	Externalities
Cost Causation Metric	# Customers	# Customers	Proxy kW	Proxy kW	Proxy kW	Proxy kW	kWh	kWh	kWh	kWh	kWh	kWh	kWh
Rate/Charge Strata 1	$7.97	$17.89	$0.17	$1.24	$2.32	($4.19)	$0.00	$0.036 ($1.1952)	$0.00	$0.081 ($0.2757)	$0.2262 ($0.745)	$0.9397 ($3.337)	$0.0403

7.4 Illustrative Full Value Tariff (Detailed Formulation)

The following tables provide detailed formulations of the illustrative FVT based on Consolidated Edison and National Grid's embedded cost of service studies, historical market supply charges, and underlying historical rate and cost structures.

7.4.1 ILLUSTRATIVE FULL VALUE TARIFF (NO EXTERNALITIES)

Table 30: Illustrative FVT for Consolidated Edison with no externality adjustment.

	Part 1	Part 2			Part 3
	Customer Charges (Embedded)	Network Subscription (Embedded)			Dynamic Prices (Marginal)
		Sub-Transmission	Distribution	Other (MAC, Capacity, etc.)	LBMP + ICAP + T&D + MFC + Adders
Cost Causation Metric (proxy)	# Meters	X Factor Size	X Factor Size	X Factor Size	Energy (kWh)
Rate/Charge Strata 1	$20.67	$1.31 / kW proxy-mo.	$9.08 / kW proxy - mo.	$3.66 / kW proxy - mo.	$0.1153 Max = ($5.1916)
Rate/Charge Strata 2					
Rate/Charge Strata 3					
Rate/Charge Strata 4					
Rate/Charge Strata 5					

Table 31: Illustrative FVT for National Grid with no externality adjustment.

	Part 1	Part 2			Part 3
	Customer Charges (Embedded)	Network Subscription (Embedded)			Dynamic Prices (Marginal)
		Sub-Transmission	Distribution	Other (MAC, Capacity, etc.)	LBMP + ICAP + T&D + MFC + Adders
Cost Causation Metric (proxy)	# Meters	X Factor Size	X Factor Size	X Factor Size	Energy (kWh)
Rate/Charge Strata 1	$23.89	$1.68 / kW proxy-mo.	$2.56 / kW proxy - mo.	$0.22 / kW proxy - mo.	$0.0646 Max = ($4.7545)
Rate/Charge Strata 2					
Rate/Charge Strata 3					
Rate/Charge Strata 4					
Rate/Charge Strata 5					

7.4.2 ILLUSTRATIVE FULL VALUE TARIFF (WITH EXTERNALITIES)

Table 32: Illustrative FVT for Consolidated Edison with an externality adjustment (no change in total revenue requirement collected by utilities but dynamic price increases and 'Other' portion of the Network Subscription charge is refunded or credited for utility over-collection).

	Part 1	Part 2			Part 3
	Customer Charges (Embedded)	Network Subscription (Embedded)			Dynamic Prices (Marginal)
		Sub-Transmission	Distribution	Other (MAC, Capacity, etc.)	LBMP + ICAP + T&D + MFC + Adders
Cost Causation Metric (proxy)	# Meters	X Factor Size	X Factor Size	X Factor Size	Energy (kWh)
Rate/Charge Strata 1	$20.67	$1.31 / kW proxy-mo.	$9.08 / kW proxy - mo.	($2.22) / kW proxy - mo.	$0.1504 Max = ($5.22686)
Rate/Charge Strata 2					
Rate/Charge Strata 3					
Rate/Charge Strata 4					
Rate/Charge Strata 5					

Table 33: Illustrative FVT for National Grid with an externality adjustment (no change in total revenue requirement collected by utilities but dynamic price increases and 'Other' portion of the Network Subscription charge is refunded or credited for utility over-collection).

	Part 1	Part 2			Part 3
	Customer Charges (Embedded)	Network Subscription (Embedded)			Dynamic Prices (Marginal)
		Sub-Transmission	Distribution	Other (MAC, Capacity, etc.)	LBMP + ICAP + T&D + MFC + Adders
Cost Causation Metric (proxy)	# Meters	X Factor Size	X Factor Size	X Factor Size	Energy (kWh)
Rate/Charge Strata 1	$23.89	$1.68 / kW proxy-mo.	$2.56 / kW proxy - mo.	($5.09) / kW proxy - mo.	$0.0880 Max = ($4.7836)
Rate/Charge Strata 2					
Rate/Charge Strata 3					
Rate/Charge Strata 4					
Rate/Charge Strata 5					

7.5 Rate and Tariff Analysis

This provides an overview of the model developed by E3 to estimate the potential effects of various rate designs on customer bills in New York. The model is *not* intended to be a full rate-design model, in which system costs are apportioned out to different customer classes in an attempt to ensure that costs for different components are recovered (insofar as possible) from those customers that cause them. Rather, the model uses billing determinants and usage patterns from 2012 to estimate the electricity bills that a customer would have paid under a variety of rate designs given their usage patterns, location within New York, and Distributed Energy Resources available to customers.

Where possible, inputs were informed by existing rates, energy prices, and utility obligations (e.g. cost recovery for rate base expenditures). However, there were many instances in which the components of existing rates had to be adjusted/changed to ensure a fair comparison across different rate designs. These changes are described in detail below.

It is important to note that the model does not reflect the long-term impacts (whether financial or behavioral) of the re-designed rates. Generating a numerical estimate of the long-term conservation, efficiency, adoption, etc. impacts of the different rate designs would require a much more detailed model and more granular information about individual customers' usage patterns and responses to changes in electricity price.

Instead, the model provides a high-level look at how a given customer's bill will vary under different rate designs and with the addition of different Distributed Energy Resources (e.g. rooftop solar PV, more efficient appliances). It also allows the user to specify how a customer will adjust their consumption in response to changes in the price of their electricity.

7.5.1 DATA INPUTS

7.5.1.1 Energy Costs and Existing Rates

7.5.1.1.1 Embedded Cost Data

To determine the revenue needed to cover the costs of each utility's existing (rate base) facilities, E3 relied on the Embedded Cost of Service (ECOS) studies that each utility files with the New York Department of Public Service. These filings build up the total annual revenues necessary to cover each utility's rate base expenditures and costs of operation, including physical investments, the administrative costs of providing electrical service, and taxes on the utility's income.

In the embedded cost filings, utilities break the embedded costs down by rate schedule for the purposes of ensuring proper cost recovery from each customer segment. For the purposes of presentation and comparability between utilities, E3 aggregated this data into five customer classes: Residential, Small General, Large General, Lighting, and Other (where necessary)[77]. Costs are further broken down by function (Generation-, Transmission-, Distribution-, and Customer-related expenses) and classification (Demand, Energy, and Customer) to describe the manner in which costs should be collected from customers. The embedded costs described in each utility's filing are summarized according to these categories (Customer Class, Function, and Classification) for inclusion in the model.

7.5.1.1.2 Marginal Cost Data

E3 also gathered information about the costs of expansions to the various utility systems for inclusion in the modeled rate designs. This information comes from the Marginal Cost of Service (MCOS) study which, like the ECOS study, the Department of Public Service requires each utility to file periodically as part of their rate cases. These filings describe the costs that each utility would incur to upgrade their transmission, sub-transmission, and distribution facilities, as well as the cost of connecting an additional customer to their system.

Each of the filings presents the marginal cost data in a slightly different format: ConEd projects the marginal costs for each of the different system components (Transmission, Switching Stations, Feeders, etc.) on a $/kW basis over the next decade. The filing by Rochester Gas and Electric (RG&E) calculates the marginal costs of system upgrades on a per customer, per kW, or per kWh basis to reflect the variety of ways that the costs of system upgrades could be collected from customers.

To incorporate this data into the rate modeling, E3 took the marginal equipment costs in $/kW (wherever possible) to provide comparability across utilities.

7.5.1.1.3 Existing Rates

To provide a baseline against which other rate designs could be compared, E3 examined utility tariffs to determine existing rates during the examined period. E3 paid particular attention to

[77] For example, Consolidated Edison Company of New York (ConEd) has rate schedules for "Electric Traction Systems," in which the electricity is used "in connection with the operation of a railroad or rapid transit system." This Service Class was included in the "Other" category.

customer and delivery charges (whether time-invariant or time-of-use based) and the non-bypassable charges (NBCs) included on every bill. These charges included the System Benefits Charge (used to fund "public policy initiatives not expected to be adequately addressed by New York's competitive electricity markets") and a surcharge for New York's Renewable Portfolio standard, among other adjustments.

These rates also include the Merchant Function Charge, levied in order to recuperate the administrative costs of providing energy service to those customers who do not opt to purchase their energy from a competitive energy supplier.

7.5.1.1.4 Market Supply Costs

E3 collected data on the utilities' costs of purchasing energy for delivery to customer, a service they provide to those customers who have contracted with an Energy Supplier for their energy service. These costs are passed through to consumers in the form of the Market Supply Charge. The Market Supply Charge is calculated to reflect the load-weighted average cost of procuring energy from the day-ahead market for a given customer class, as well as that class's share of the capacity costs incurred by the utility when purchasing their capacity in the Installed Capacity (ICAP) market. Along with the MSCs, utilities also calculate and post regular MSC Adjustments, which are used to reconcile the MSCs posted in advance of the time during which they apply (calculated based on projections of energy prices) with the *actual* day-ahead energy prices during that same time. These adjustments also reflect the costs or benefits of any hedges in place for the utility.

7.5.1.2 NYISO Location-Based Marginal Prices and Installed Capacity Auction Results

E3 also incorporated the real-time hourly energy prices from the NYISO and the results of the ICAP auctions, in which the utilities contract with capacity resources to ensure that they have sufficient contracted generation to meet their reserve requirements. These prices represent the geography- and time-dependent value of energy and capacity in New York State during 2012.

7.5.2 CUSTOMER BILLING DETERMINANTS

7.5.2.1.1 Customer Demand Data

E3 was provided with customer data for two utilities, ConEd and National Grid. This data consisted of a number of load shapes, grouped into strata based on annual consumption. For each of the different strata, the utilities provided hourly consumption profiles for Low, Medium, and High usage consumers. These profiles were used as the representative consumption patterns for customers in each utility.

7.5.2.1.2 Distributed Generation Output Profiles

As part of its work on the Net Energy Metering analysis for the state of New York, E3 compiled sample hourly solar and wind generator output shapes for locations across New York. A selection of these profiles, located in the National Grid and ConEd service territories, was included in the model so that they could be paired with the customer consumption data described above.

7.5.2.1.3 Energy Efficient Resource Profiles

E3 also included load reduction profiles for efficiency improvements to the customer's in-home appliances to examine the impact that installing energy efficient appliances would have on a customer's electricity bill under the various rate designs examined. Specifically, load reduction shapes for efficiency upgrades to the freezer, air conditioning, and lighting were included in the model, taken from the Department of Energy's Better Buildings Residential Program Cost-Effectiveness tool.[78]

7.5.3 SYSTEM CHARACTERISTICS

7.5.3.1 Substation / NYISO Load Profiles

Both ConEd and National Grid provided E3 with hourly substation load profiles for a variety of substations on their distribution network. These load profiles were used to identify specific substations that were operating at or near capacity, and as such would need to be upgraded in

[78] Available at **http://energy.gov/eere/better-buildings-residential-network/resources#cost**

the absence of downstream load reductions, whether from distributed generation resources, demand response programs, energy efficiency measures, or load shifting.

E3 also incorporated zonal and statewide loads in the model, downloaded from the NYISO website, to identify those periods in which the sub-transmission or transmission systems would be experiencing the highest loads. The usage during these hours is likely to trigger system upgrades unless reduced through load reductions or offset by strategically placed generation.

7.5.4 MODELING LOGIC

E3's model is designed to be a high-level imitation of the ratemaking process, in which the costs of providing electric service to customers are totaled and the component parts of a customer's electricity rate (customer, demand, and energy charges) are designed to recover those costs. As part of the NY REV process, E3 was asked to examine a variety of mechanisms for cost-recovery and examine each design's ability to equitably recover costs from customers, compensate distributed energy resources (including both generation and load-reduction resources), and encourage behavior to reduce the need for additional transmission and distribution resources.

To ensure comparability across designs, there were instances in which the existing rates needed to be modified or adjusted. For example, ConEd calculated a "Monthly Customer Cost" of $22.14 for the Residential service class in their ECOS filing, more than six dollars higher than the $15.76 monthly charge in their tariff, meaning that existing rates are not sufficient to collect the embedded costs assigned to the Residential class. Were E3 to compare modeled rates (designed to collect all of the assigned costs) to the existing rates without any adjustments, the modeled rates would be higher (i.e. more expensive to the consumer) than the existing rates by default, obscuring differences caused by the design of the rates.

To account for this, many of the components of the existing rates were "trued-up" to ensure that the compared rate designs would be revenue-neutral. This included calculating an adder at a level that would result in full collection of the embedded costs in the ECOS filing when applied to the billing determinants contained in that same filing. Similarly, though New York utilities posted the MSCs for the period covered in the model, the energy portion of the MSCs used in the calculation of the sample bills were built up from scratch based on the LBMPs posted on the NYISO website. This, again, was done to ensure that differences in the calculated customer bills were due to differences in rate designs rather than the data underlying the components.

7.5.4.1 Modeled Rates

The following section describes the process of generating the rates used to construct the customer bills for comparison. All modeled rate designs included the non-bypassable charges (RPS adder, System Benefits Charge, etc.) as well as the Merchant Function Charge as calculated by the relevant utility. The remaining components vary by rate design, but are all designed to collect the same amount of revenue from the customer class as a whole.

7.5.4.2 Existing Rates

The structure of the existing rates was taken from the filed tariffs, with adjustments made to the MSC and Delivery charges to ensure the proper cost collection. Customer charges were set at the level in the filed tariff, while (as described above) an adder was calculated to ensure full collection of assigned embedded costs across the rate class. Energy prices were calculated based on NYISO LBMPs, either on a monthly basis (for the normal time-invariant rate) or monthly by time-of-use (TOU) period.[79]

7.5.4.3 Opt-In Real Time Pricing

The first option modeled by E3 would allow customers could opt-in to real-time pricing, installing a meter that would be able to determine, on an hourly basis, whether a customer was a net consumer or exporter (as a result of installing behind-the-meter generation) of energy.

Energy price in this design is determined by the LBMP, taking into account distribution system losses. The hourly energy price, like the MSC, includes a capacity component to collect the cost of contracting capacity through the ICAP market. The Customer Charge and the Delivery Charges remain the same as those in the existing rates.

[79] The Time-of-Use periods used in the modeling are those defined by the utilities for their own Time-of-Use rates.

7.5.4.4 Dynamic Pricing

The second alternative rate design modeled by E3 switches all customers to an hourly rate with a meter that can measure consumption and generation (if necessary) independently. Energy prices are calculated in the same manner as in the opt-in rate described above.

Under the "Dynamic Pricing" rate, the utility employs high prices during constrained hours (whether on the distribution, sub-transmission, or transmission system) to discourage consumption in hopes that a mixture of efficiency, conservation, and down-system generation will allow them to defer upgrades to these systems. On the distribution level, the per-kW-year Marginal Cost of Distribution upgrades (taken from the utility's MCOS) is allocated across the hours in which the local substation is near or above capacity. This is to encourage customers to shift their consumption to a less constrained time period, reduce their consumption through efficiency upgrades, and install new behind-the-meter generation that can export energy to the grid during these constrained periods.

E3 also modeled an interim TOU-based "Dynamic Pricing" option, in which the energy and "dynamic value" prices are evenly allocated over the TOU hours within a month.

7.5.4.5 Network Subscription

The "Network Subscription" option employs the same hourly, real-time price scheme for the energy portion of the customer bill, along with the time- and location-specific "dynamic value" adders during constrained hours.

The embedded cost portion of the bill is collected via a size-based customer charge, differentiated by the customer strata provided by utilities. Using the billing determinants in the ECOS filings, E3 estimated the number of customers in each strata. Embedded costs functionalized as "Customer" costs were allocated based on the number of customers in each strata, while embedded costs that were functionalized as "Demand" or "Energy" costs were allocated according to the total energy usage within that strata (average usage in the strata multiplied by the estimated number of customers in the strata).

Similarly to the "Dynamic Pricing" option, E3 also generated a TOU-based version of the "Network Subscription" rate design, in which rates for each TOU period are determined by averaging over the monthly TOU periods.

7.5.5 DISTRIBUTED ENERGY RESOURCES

E3 also modeled a number of distributed energy resources (DERs) that a customer could install to reduce their billed consumption, including generation options (solar or wind), energy efficiency upgrades, and conservation in response to high dynamic prices. The following section describes the implementation of these different options in the model.

7.5.6 GENERATION OPTIONS

E3 modeled the impact of installing behind-the-meter generation on the customer bills under the different rate designs, with a focus on the extent to which the different designs enable the utility to properly collect embedded cost contributions from customers while fairly compensating them for the energy that they produce. As part of this examination, E3 modeled both a "Net Energy" option (in which customers can offset their consumption at the full retail rate) and a "Buy-All, Sell-All" option (in which the customer is billed for all of their consumption and compensated separately for the generation produced by the DER).

The user of the model can select the size of the generation by selecting the total percentage of the customer's annual consumption that they would like to offset with generation. The kW size of the generation installed is chosen to produce that amount of energy, given the output profile of the generator (as described in the section on Distributed Generation Output Profiles above).
Under the "Net Metering" option, the consumption offset provided by generation is dependent on the time period over which consumption is billed. Currently, most New York customers do not have interval meters which would allow the utility to monitor their consumption / generation in real-time, so behind-the-meter generation simply reduces the customer's billed usage at the full retail rate on a month-by-month basis. E3 also modeled the situation in which utilities upgrade customer meters to allow them to monitor usage on an hourly basis, which

would allow a utility to differentiate, on an hourly basis, between generation that offsets a customer's usage and generation that is actually exported to the grid.

Under the alternative rate designs modeled by E3, these different types of generation (offsetting the customer's usage as opposed to exported to the grid) are compensated at different rates: generation that reduces the customer's consumption of grid-supplied electricity (on an hourly basis) is credited at the full, per-kWh rate (including any volumetric embedded cost recovery like Delivery charge or the per-kWh embedded cost recovery in the Dynamic Pricing rate option), while generation that is exported to the grid is compensated at the current energy rate (whether hourly or TOU based) plus any hour- or location-specific "Dynamic value" adders, but is *not* paid the value of rate components that are designed to collect embedded costs.

As a method to compare generator compensation under the various rate design options, E3 calculates the ratio between the value of the generation to the customer (i.e. the total reduction in customer bill) and the value of the generation to the system, taking into account the real-time energy value of the actual kWh production of the generator. When generation output is able to reduce the customer's embedded cost responsibility, the value of the generation resource to the customer will be greater than the value of the generation resource to the system.

7.5.7 ENERGY EFFICIENCY MEASURES

As described above, E3 also modeled the impact of a number of different energy efficiency appliance upgrades. In contrast to the generation options, all energy efficiency measures represent reductions in demand behind the meter, and as such reduce customer costs by the full prevailing retail rate at the time of the efficiency improvement.

7.5.7.1 Price-Based Conservation Response

The final method of load reduction modeled by E3 was to examine the potential for customers to reduce their usage in response to high dynamic prices. The user can set the level of the price response (the price elasticity of demand), and the model will calculate a new hourly consumption profile based on the difference between the existing rates and the hourly cost of energy in the alternative rate design. In recognition of certain inflexible loads, consumption reductions in response to price spikes are capped at a user-specified level. Similar to load reductions resulting from efficiency improvements, reductions due to price-based conservation offset the customer’s billed usage at the full retail rate.

7.6 Smart Home Model

7.6.1 OPPORTUNITY AND BACKGROUND

Economists have long claimed the benefits of real-time pricing (RTP) based on marginal cost, but the vast majority of customers are not in a position to respond easily to changing prices, particularly in the residential market. The ability of customers to respond can change dramatically with connected autonomous home energy controls and, with the right compensation, loads could become a valuable resource and not an uncontrolled liability.

The technology for home energy optimization and control has arrived through the advent of cheap integrated circuits, controls, and ubiquitous internet access. Yet innovation in home energy control has remained slow for many reasons, the lack of adequate compensation mechanisms for small customer participation among them. The marginal cost of electricity service is highly variable, both temporally and spatially, but residential and small commercial utility rates do not reflect this variability in an effort to prioritize designs that are easily understood and implemented.

Under RTP, it is possible to analyze the potential intersection of customer load behavior with electricity system marginal cost to understand where load shifting behaviors can provide large electricity system benefits with minimal customer impacts. We take a first step towards achieving this with our integration of a physical customer model and a customer preference model with an electric rate model. This home energy optimization allows us to explore potential flexible load operations for space conditioning, water heating, electric vehicle charging, and home battery operations. We show meaningful reductions in utility cost of service with minimal (an often positive) impacts on customer service quality.

7.6.2 SMART HOME DESCRIPTION

7.6.2.1 Customer Comfort Preferences

Assessing total customer utility of dispatchable load requires both an understanding of the monetary implications of load dispatch in terms of total customer bills and also a framework for assessing non-monetary customer utility. To achieve this, we use comfort penalty prices to inform our dispatchable load optimization. In this framework, any deviations from the ideal operating behavior of customer load is assessed a monetary penalty. This monetary penalty determines the "flexibility" of the customer load in time.

7.6.2.2 Modeling Methodology

The model used in this analysis has three main components that are used in a home energy optimization:

+ Customer Load Modeling: Physical representation of customer electric load devices i.e. thermal characteristics of water heater used to convert electric demand into physical equipment performance and demand.
+ Customer Comfort Preferences: Calculation of the penalty for deviation of customer electric loads from base case, inflexible operating behavior.
+ Rates: Customer pricing signals developed from utility avoided costs.

7.6.2.3 Input Parameters

7.6.2.3.1 Home descriptions

The home is described by three main components: the physical house itself, the house's annual weather and the house's occupant or customer.

Particularly important for modeling the HVAC system, described below, several key traits of the house itself must be known: the size of the house (volume; surface area of the floor/roof; location and size of windows, thermal mass, etc.). These factors play a key role in the heat loss or gain that the house experiences with fluctuations in outdoor temperature and solar exposure, as well as fully-describing the efficiency of the home.

Additionally, each house is mapped to an hourly weather file, containing: solar zenith; solar azimuth; direct normal irradiance (DNI); diffuse horizontal irradiance (DHI); global horizontal irradiance (GHI); outdoor temperature; outdoor and indoor total pressures; outdoor relative humidity. From this set of raw data, and given the physical description of the home, natural hourly heat loss or gain can be calculated.

Finally, each home needs a customer. While the required inputs for each customer vary depending on the technology discussed (and, thus, are discussed in more detail below), the union of these input sets comprise the behavior and preferences of the home's energy consumer.

7.6.2.3.2 Technologies

Our model optimizes electricity consumption with regard to four different end-use technologies: heating ventilation and air conditioning (HVAC), electric vehicle (EV), home battery, and electric water heater. While the general structure of each optimization is the same, the particular input parameters vary somewhat.

The key input parameters of the HVAC pertain to the HVAC itself: interior set points for cooling and heating modes and SEER rating are passed to the model as raw inputs. The actual HVAC system is sized according to a methodology which takes into account the square footage, occupancy and ceiling height of the home.[80] The details of the home, its weather, its interior set points and the size of its HVAC provide a complete set of parameters needed for our optimization.

The EV's input parameters are a bit more involved. First, the model requires the expected parameters concerning the battery: size, max charge/discharge rate, static loss rate, minimum

[80] http://homeguides.sfgate.com/figure-btus-hvac-sizing-68206.html

state of charge of the battery and transmission losses between the charger and the battery. These specific parameters, along with the analogous parameters for the home battery, are found below.

In addition to the physical constraints of the EV, some assumptions about the behavior of the customer are required, as well. First, we create a weekend and weekday trip-taking schedule for the EV. A day's trip-taking schedule consists of two 24-hour vectors, one indicating how many kWh are used in a given hour, the other indicating if the EV is available to charge or discharge in that hour (as a car cannot be simultaneously driving on the road and charging its battery). For this iteration of the model, our weekday trip consisted of a 9 kWh trip lasting from 8am to 5pm, whereas our weekend trip consisted of a 9 kWh trip lasting from 9am to 2pm. Because people's driving behavior is more probabilistic than this rigid schedule, we use a weekend/weekday 24-hour probability vector of a customer's using her vehicle,[81] given below, which penalizes the car for sitting in a discharged state when there is a high probability of a trip:

Figure 50: Probability of initiating a vehicle trip by hour of day

[81] Derived from the National Household Travel Survey **http://nhts.ornl.gov/**

This vector is combined with a piecewise linear function that gives the probability that a battery has insufficient energy, given a distribution of trip lengths (as a function of the % charge of the battery). The result is a penalty function that gives the likelihood that a customer won't have enough energy in her vehicle when she would like to use it. Namely:

$$Energy\ Violation_h = \boldsymbol{P}(Insufficient\ Energy_h | Use\ EV_h) * \boldsymbol{P}(Use\ EV_h)$$

The input parameters for the home battery are identical to those of the EV except that there are no trips for the home battery and, thus, it is always available for charge and discharge. The EV and home battery's respective input parameters are summarized in the following table.

Table 34: EV & Home Battery Input Parameters

Input Parameter (Units)	EV Value	Home Battery Value
Size (kWh)	12	9
Max Charge Rate (kW)	6.6	4.5
Max Discharge Rate (kW)	6.6	4.5
Static Loss Rate (kW)	0	0
Minimum State of Charge (kWh)	0	0
Transmission Losses (%)	10%	10%

The fourth technology modeled for our smart home is an electric water heater. Similar to both the EV and home battery, the raw input parameters for the water heater pertain to its physical specifications, given below.

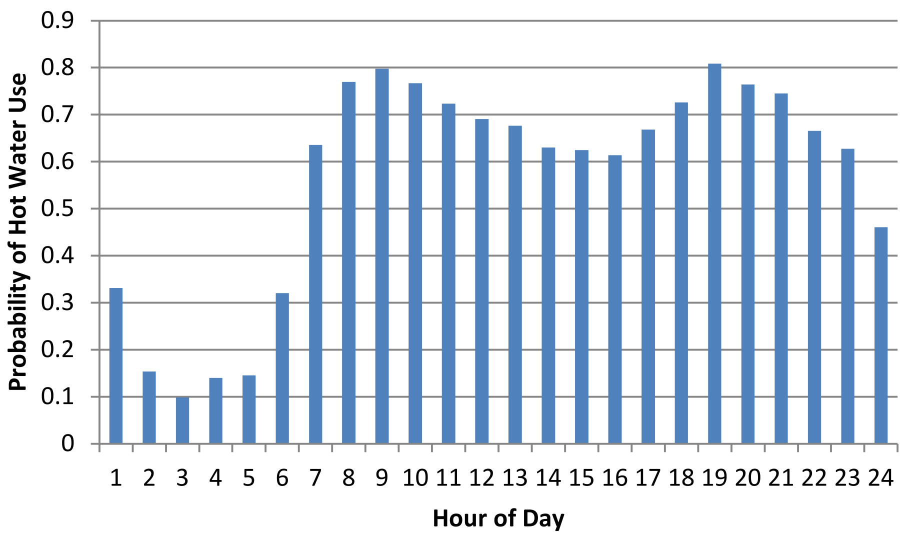
Table 35: Water Heater Input Parameters

Input Parameter (Units)	Value
Heat Pump Max Power (W)	680
Heat Pump COP	2.3
Heat Pump Max Temperature (°F)	120
Water Tank Capacity (Gallons)	60
Water Tank Standby Losses (Btu/hour)	1000
Water Tank Ambient (°F)	70
Heating Element Max Power (W)	4500

Heating Element COP	0.98
Water Heater Max Power (W)	4500
Water Heater Max Temperature (°F)	140
Water Heater Set Point (°F)	130
Water Heater Cold Water Temperature (°F)	58

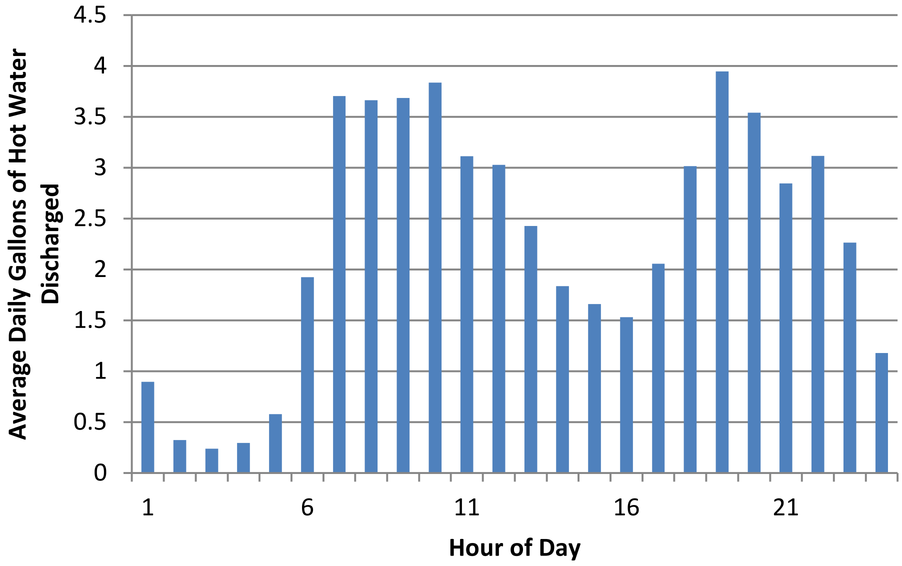
Analogous to the EV and home battery usage probabilities, we combine a 24-hour vector of the probability that a customer uses their hot water with a piecewise linear function to model the probability that a customer's hot water needs are not sufficiently met.

Figure 51: Probability of customer hot water use by hour of day



Furthermore, the water heater technology takes an input parameter analogous to the EV's trip-taking, in the form of an 8760 vector reporting the number of gallons used by the customer. Similar to the trip schedule tracking energy discharged from a customer's EV, this vector is used to track the energy lost from the "discharging" of the hot water from the water heater. The following figure displays the average daily gallons discharged over the course of the year by hour of the day.

Figure 52: Average hot water use by hour of day



7.6.3 SMART HOME VALUE

Smart home value can be broken into three main categories: load shifting, energy efficiency or conservation, and customer experience. Load shifting is a change to the timing of consumption patterns but no fundamental change to the amount of service consumed. Energy efficiency and conservation are reductions to the amount of energy consumed—the difference being that conservation directly impacts the customer whereas energy efficiency does not. Finally, customer experience is a combination of customer value of service, service quality, and other intangibles. Here we focus primarily on load shifting but discuss the other two categories at the end of this section.

For illustration of the smart home value this section uses a case study of a single family home in the NYC area within the Con Ed. service territory. The table below gives an overview of the home simulated.

Table 36: Building simulation parameters

Customer Equipment	Annual Consumption (kWh)
Square footage	2,500 ft^2
Number of floors	1
Number of bedrooms	3
Year built	2009
Heating set point	71 F
Cooling set point	76 F
HVAC size	18626 W
BEV size	12 kWh
Home battery size	9 kWh

Parameters describing the tightness, insulation, and building operations were taken from the 2014 Building America House Simulated Protocols[82] with minor adjustments after benchmarking HVAC energy consumption to the EIA Residential Energy Consumption Survey.[83] Weather data from Weather Source[84] and solar insolation data from Solar Anywhere[85] is used in the building simulation.

In addition to the Con Ed. residential flat tariff, two alternate rate designs are illustrated to show the impact of dynamic prices on the response of smart home equipment. The first alternative rate design, termed "Dynamic Pricing," is equal to the estimated marginal cost of service. Embedded costs are collected through a flat or invariant volumetric charge. The second rate structure illustrated is a time of use rate, which is also based on average utility marginal costs and has a fixed charge to collect some portion of embedded costs. The purpose is to illustrate the difference in customer behavior and the value to the system under different rate structures. In general, we expect that the value of smart home equipment increases with the volatility in the rates, as opportunities to arbitrage the difference between high and low cost periods increase.

[82] http://energy.gov/sites/prod/files/2014/03/f13/house_simulation_protocols_2014.pdf
[83] http://www.eia.gov/consumption/residential/
[84] http://weathersource.com/
[85] https://www.solaranywhere.com

The value of the smart home under different rate structures is calculated relative to a reference case with native consumption patterns. The native consumption pattern case is created using a model run with very high penalties on deviation away from native customer service demand.[86] Table 37 shows results from the reference case for the smart home equipment types modeled. The home battery system is not compared to a reference case and is not shown in Table 37.

Table 37: Reference case electricity consumption and annual bill

Customer Equipment	Annual Consumption (kWh)
Heat pump	5,722
Air conditioner	1,129
Heat pump hot water	3,884
Battery electric vehicle	3,660

It should be noted that heat pump and electric vehicle penetration in Con Ed. service territory is currently very low, though expected to increase, and that this case study shows baseline electricity consumption far above the current norm.

Table 38 shows bill and system cost savings from the smart home equipment under the three rate structures. Perhaps unsurprisingly, the smart home has no load shifting value under the flat rate structure. The time of use rate provides arbitrage opportunity, as does the Dynamic Pricing. The Dynamic Pricing rate results in higher bill savings to the smart home than time of use due to higher rate volatility, except in the case of the electric vehicle.

Dynamic Pricing, which is closer to true utility avoided costs, also results in less of a gap between customer compensation through bill savings and resulting changes to the cost of service. Time of use rates do not necessarily result in a mismatch between bill savings and societal benefits, as shown here. But it is more difficult to keep compensation and societal savings balanced.

The heat pump system shows little value from load shifting because the hours of heavy use are during times of the year that have relatively low load and stable prices—hence load shifting has

[86] Penalties are set arbitrarily high within the optimization and features such as scheduled precooling are removed.

little impact. If heat pump penetration were to increase dramatically, we would expect the value from smart scheduling to increase.

Table 38: Customer bill and cost of service savings from smart home under three rate structures

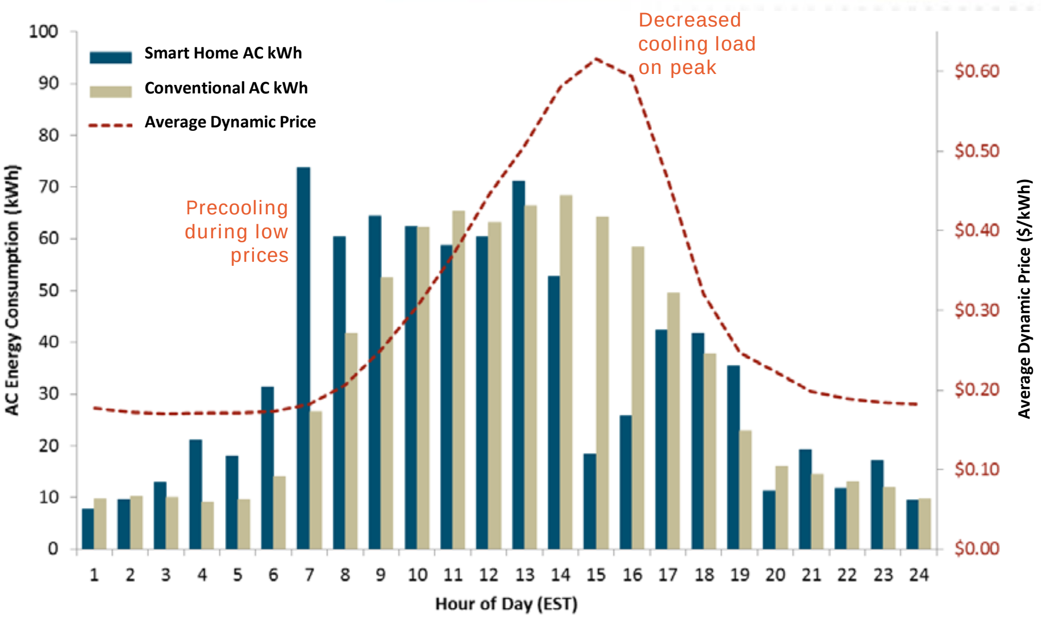
Customer Bill / Cost of Service	Flat Rate	Time-of-use	Dynamic Pricing
Heat pump	$0 / $0	$2 / $0	$33 / $38
Air conditioner	$0 / $0	$80 / $22	$195 / $199
Heat pump hot water[87]	$0 / $0	$113 / $15	$200 / $35
Battery electric vehicle	$0 / $0	$143 / $50	$66 / $66
Home battery system	$0 / $0	$331 / $158	$401 / $431

To better understand the behavior that induces bill savings in Table 38 it is instructive to look at hourly equipment energy use, shown for air conditioning in Figure 53. The gold bars show native air conditioner use in kWh for the simulated home with a peak in early afternoon. The dotted red line shows the time varying dynamic value dynamic price for this day with a peak coincident with air conditioning load. In this case the Dynamic Pricing signal is quite high and approaches $1/kWh producing a strong load shifting and conservation incentive. The smart home air conditioning use is shown in dark blue and shows a shift in load away from peak price periods.

Looking at the internal temperature for this day we observe precooling, which allows for AC load to be shifted while minimizing deviations above the indoor set point. Because a precooled home results in increased internal heat gain, the smart home consumes 4% more electricity than the baseline case. Nevertheless, the air conditioning bill for this day drops 11% due to the differences in cost when electricity is used.

[87] Case assumes no penalty for insufficiency. Cases are currently being run with different hot water penalties.

Figure 53: Smart vs. conventional air conditioner energy usage in response to an hourly dynamic price.



Smart AC assumptions: 2 degrees of precooling; Otherwise, $1/°f customer comfort penalty in each hour with a set point deviation; accurate day ahead prices and weather forecasts.

It is reasonable to assume that the smart home behavior shown in Figure 53 does impose some type of customer cost in terms of perceived comfort change. Because the smart home optimization framework puts customer comfort in economic terms we are able to quantification of this effect, shown in Table 39. Referencing Table 38 again we see that bill savings are larger than customer comfort costs showing that net customer welfare has increased in every case. This is intuitive because smart home equipment control would stop in the case that bill savings were less than customer impact.

We recognize that, while this modeling shows smart home equipment to decrease service quality by design, smart home equipment can and will improve customer comfort as well, which is the main driver of smart home technology adoption today. Smart thermostats that better anticipate thermal comfort are just one example. The value of this comfort gain is more difficult to quantify but is reported by customers[88].

[88] https://nest.com/downloads/press/documents/enhanced-auto-schedule-white-paper.pdf

Table 39: Recorded customer comfort costs from smart home measures

Customer comfort costs[89]	Flat Rate	Time-of-use	Dynamic Pricing
Heat pump	$0	($1)	$19
Air conditioner	$0	$1	$40
Battery electric vehicle	$0	$77	$26

Finally, while the benefits shown by load shifting are non-trivial and are likely to increase in importance with higher penetrations of wind and solar, the smart home benefits from energy efficiency are also significant, though not quantified here, and are likely to have several causes. The potential for direct energy savings from smarter consumption of energy services, such as reducing HVAC usage in unoccupied spaces, has been estimated at nearly 40%.[90] Second, indirect energy efficiency savings could come from multiple factors leading to more energy efficient equipment. Some of these factors include the ability to better identify equipment service needs and better qualification of bill savings from equipment upgrades.

7.6.4 SMART HOME OPTIMIZATION

In short, our model aims to capture the impact that more sophisticated pricing can have on a customer's consumption and bill savings. For each of the different technologies, our objective function contains both pricing and customer penalty elements and is minimized in 24-hour chunks for an entire year. With this framework established, different rate scenarios and customer penalties can be fed into the model and the desired impacts effectively quantified.

7.6.4.1 HVAC

7.6.4.1.1 Optimization Framework

[89] Deviations away from HVAC set point valued at $1 per degree per hour. Insufficient charge during a vehicle trip due to smart home equipment valued at $50/occurrence.
[90] http://www.cmu.edu/gdi/docs/scoping-the.pdf

Minimize:

$$\sum_{h=1}^{24}(HeatPump_h * EnergyPrice_h + \$PerDegreePenalty * PenDev_h)$$

Subject to:

$$0 \leq HeatPump_h \leq HeatPumpMax$$

$$HeatPumpBTU_h = HeatPump_h * HeatPumpSEER$$

$$TempIn_h = TempIn_{h-1} + TempGain_h - \frac{TempMode * HeatPumpBTU_h}{C_{Home}}$$

$$Dev_h = DevUp_h + DevDown_h$$

$$DevUp_h \geq TempIn_h - SetPoint$$

$$DevDown_h \geq SetPoint - TempIn\_h$$

$$PenDevBelow_h \geq DevDown_h - DevDownMax$$

$$PenDevAbove_h \geq DevUp_h - DevUpMax$$

$$PenDev_h \geq PenDevAbove_h + PenDevBelow_h$$

Where:

Variable	Value
h	Hour of day
HeatPump	Heat pump power
HeatPumpMax	Maximum heat pump power
HeatPumpBTU	BTUs delivered from heat pump
HeatPumpSEER	Power to BTU converter
EnergyPrice	$/kWh
$PerDegreePenalty	Customer penalty for deviation from acceptable set point
PenDev	Deviation from acceptable setpoint*
TempIn	Temperature inside house
TempGain	Temperature change due to solar, heat loss, etc.

TempMode	-1 (or 1), indicating if HVAC is in heating (or cooling) mode**
C_{Home}	Heat capacity of house
Dev	Deviation from interior set point
DevUp	Deviation above interior set point
DevUpMax	Allowable deviation above set point before penalty is incurred
DevDown	Deviation below interior set point
DevDownMax	Allowable deviation below set point before penalty is incurred
SetPoint	Interior set point
PenDevBelow	Deviation below acceptable set point*
PenDevAbove	Deviation above acceptable set point*

*Acceptable set point: One of the main points of interest in simulating HVAC technology was capturing the potential for pre-cooling or -heating a home when energy prices are cheap. To capture this functionality, we created an asymmetric deviation allowance. That is, when the HVAC is in cooling mode, the interior temperature may deviate below the interior set point by a specified amount without incurring a penalty (pre-cooling), but a penalty is incurred for any deviation *above* said set point. An analogous, but opposite, procedure takes place on heating days. In summary, the model behaves as follows:

Heat Mode	DevUpMax	DevDownMax
Cooling Day	0	DeviationTolerance
Heating Day	DeviationTolerance	0

**Heat Mode: Though common in simulation to assign an HVAC to heating or cooling mode based on average monthly temperature, among other things, we found that this monthly level of granularity (as well as even a daily level) was too broad for our purposes. That is, months with low enough monthly temperatures to be considered heating months would feature days warm enough to heat the house beyond a reasonable level, i.e. a level at which point a customer would simply turn his air conditioner on. To circumvent this issue, the model runs each day of the year in both heating and cooling more, and then selects the mode associated with greater customer comfort. To prevent gaming within the optimization we do not allow the system to switch between heating and cooling modes within the day.

7.6.4.1.2 Customer Comfort

The customer preference parameters for the HVAC optimization amount to a deviation tolerance (DeviationTolerance above) and a deviation penalty ($PerDegreePenalty above). Our model is capable of iterating through any combination of values for these two parameters, to model both flexible and more demanding customers.

7.6.4.2 Heat Pump Hot Water

7.6.4.2.1 Optimization Framework

Minimize:

$$\sum_{h=1}^{24} (ElementPower_h * EnergyPrice_h + HPPower_h * EnergyPrice_h + ProbCustShortage_h * ProbUsingWater_h * CustomerPenalty)$$

Subject to:

$$StateOfCharge_h = StateOfCharge_{h-1} + HEGain_h + HPGain_h - WaterLoss_h - HeatLoss_h$$

$$HeatLoss_h = TempDiff_h * LossPerDegree$$

$$ProbCustShortage_h = Insufficiency_{Slope} * \left(\frac{StateOfCharge_h}{MaxCharge}\right) + Insufficiency_{Intercept}$$

$$0 \leq HPPower_h \leq MaxHPPower$$

$$0 \leq HEPower_h \leq MaxHEPower$$

$$StateOfCharge_h \leq MaxCharge$$

$$StateOfCharge_h - HPMaxCharge \leq (1 - HPAvailability_h) * M$$

$$HPPower_h \leq MaxHPPower * HPAvailability_h$$

Where:

Variable	Value
h	Hour of day
ElementPower	Power used by heating element
EnergyPrice	$/kWh
HPPower	Power used by heat pump
ProbCustShortage	Probability that customer has insufficient hot water
ProbUsingWater	Probability that customer uses hot water
CustomerPenalty	$ penalty for insufficient hot water
StateOfCharge	Btu in water tank
HEGain	Btu gained via heating element
HPGain	Btu gained via heat pump
WaterLoss	Btu lost via usage of hot water
HeatLoss	Btu lost due to lower ambient temperature
TempDiff	Difference between hot water and ambient temperature
LossPerDegree	Parameter of water heater
Insufficiency	Pre-processed arguments
MaxHPPower	Maximum allowable heat pump power
MaxHEPower	Maximum allowable heating element power
MaxCharge	Maximum allowable state of charge of water tank
HPMaxCharge	Maximum allowable charge of heat pump
HPAvailability	0 when tank temperature exceeds heat pump max temperature
M	Arbitrarily large number for purposes of constraint

7.6.4.2.2 Customer Comfort

The customer preference parameter for the water heater optimization is a dollar-value penalty (CustomerPenalty above) that scales with the probability of insufficient hot water.

7.6.4.3 Battery Electric Vehicle

7.6.4.3.1 Optimization Framework

Minimize:

$$\sum_{h=1}^{24} (ChargeRate_h * EnergyPrice_h + ProbCustShortage_h * ProbUsingEV_h * CustomerPenalty)$$

Subject to:

$$ProbCustShortage_h = Insufficiency_{Slope} * \left(\frac{StateOfCharge_h}{MaxCharge}\right) + Insufficiency_{Intercept}$$

$$MinCharge \leq StateOfCharge_h \leq MaxCharge$$

$$ChargeRate_h - MaxChargeRate * EVAvailable_h * ChargeOn_h \leq 0$$

$$0 \leq MaxDischargeRate * EVAvailable_h * DischargeOn_h - DischargeRate_h$$

$$StateOfCharge_h = StateOfCharge_{h-1} + TransLoss * ChargeRate_h - \frac{DischargeRate_h}{TransLoss} - EVUse_h$$

$$0 \leq ChargeOn_h + DischargeOn_h \leq 1$$

$$StateOfCharge_0 = StartingCharge$$

Where:

Variable	Value
h	Hour of day
ProbCustShortage	Probability that customer has insufficient charge
Insufficiency	Pre-processed arguments
StateOfCharge	kWh in battery
MaxCharge	Max kWh in battery
MinCharge	Minimum state of charge of battery
ChargeRate	kW into battery

MaxChargeRate	Max kW into battery
EVAvailable	True/False where EVAvailable = 1 means EV is available to charge
ChargeOn	True/False where ChargeOn = 1 means ChargeRate > 0
MaxDischargeRate	Max kW out of battery
DischargeOn	True/False where DischargeOn = 1 means DischargeRate > 0
TransLoss	Transmission losses factor
EVUse	kWh lost due to an EV trip
StartingCharge	Required initial state of charge for the day

7.6.4.3.2 Customer Comfort

The customer preference parameter for the EV optimization is a dollar-value penalty (CustomerPenalty above) that scales with the probability of insufficient energy in the EV battery.

7.6.4.4 Energy Storage

7.6.4.4.1 Optimization Framework

As mentioned above, the energy storage optimization framework is identical to that of the electric vehicle, with a couple of exceptions. First, EVUse = 0 for all hours. Secondly, “vehicle-to-grid” action is enabled for the home batteries. That is, the objective function is the following, with the same definitions as above.

$$\sum_{h=1}^{24}((ChargeRate_h - DischargeRate_h) * EnergyPrice_h)$$

DischargeRate is subtracted from ChargeRate and the difference is then applied to EnergyPrice. In other words, a home battery user can *earn* money by selling power back to the grid.